Report on

THE NJECL WORKSHOP ON STEAM-INJECTED GAS TURBINES FOR CENTRAL STATION POWER GENERATION

held April 3, 1986

New Jersey Energy Conservation Laboratory*
Center for Energy and Environmental Studies
Princeton University
Princeton, NJ 08544

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September 25, 1986

* Established within the Center for Energy and Environmental Studies in January 1985, the New Jersey Energy Conservation Laboratory (NJECL) conducts research in important areas of energy conservation relevant to the State of New Jersey. Funding for NJECL is provided largely by the 7 electric and gas utilities in New Jersey and the New Jersey Department of Energy, with complementary support from the Prudential Insurance Company, Hoffman-LaRoche, and the New Jersey Energy Expo.

ABSTRACT

The NJECL Workshop on Steam-Injected Gas Turbines was held to help clarify issues related to the development of the Intercooled Steam-Injected Gas Turbine (ISTIG) for central station powerplant applications. In addition to technical issues relating to ISTIG, the Workshop dealt with the natural gas supply outlook, the Powerplant and Industrial Fuels Use Act (FUA), electric utility interest in non-peaking gas turbines, and vendor interests in developing these markets.

ISTIG is one of several advanced gas turbine technologies which would be competitive with both new coal and nuclear plants and existing gas-steam plants and which offer complementary attractions of relatively small scale, short lead times, low capital costs, low pollutions levels, and fuel flexibility.

The Workshop found no obvious technical obstacles to the development of the ISTIG. In addition, since ISTIGs could be shifted to gasified coal, the uncertain long-term natural gas supply picture would not be a constraint to initial firing of ISTIG units with natural gas.

The ISTIG is unlikely to be developed quickly in the US, however. The FUA is constraining utility interest, and utilities are reluctant to build any new plants, given today's uncertain electricity demand outlook and regulatory environment. In addition, because of this uncertain utility market and a strong military aircraft turbine market, vendors capable of developing the aircraft-derivative ISTIG are not anxious to do so.

New public policies that encourage the efficient use of natural gas by utilities and gas turbine R&D aimed at utility applications could lead to the near term commercialization of several advanced gas turbine technologies. Such policies would help foster lower electric utility rates and help reap major civilian sector benefits from the enormous advances in military aircraft technology that have been made possible by Defense Department R&D support.

The Workshop was attended by all gas and electric utilities in New Jersey, major vendors of aircraft-derivative gas turbines, gas and electric utility trade organizations, and other vendors and utilities interested in STIGs:

W. Alley (Arkansas P & L)
C. Ashworth (Pacific Gas & Electric)
S. Baldwin (Princeton University)
D. Brown (Public Service Elec. & Gas)
J. Burkett (ASEA-STAL)
G. Cain (Mechanical Technology)
S. Consonni (Princeton University)
J. Corman (General Electric)
M. Curley (NERC)
K. Deffeyes (Princeton University)
G. Edinger (NJ Natural Gas)
N. Esposito (Jersey Central P & L)
W. Flye (Stewart & Stevenson)
R. Foster-Pegg (formerly Westinghouse)
S. Gabel (NJ Board of Public Utilities)
M. German (American Gas Association)
I. Glassman (Princeton University)
C. Graham (DOW, retired)
B. Grossman (South Jersey Gas)
R. Kidder (Allison Gas Turbines)
E. Larson (Princeton University)
E. Linky (NJ Department of Energy)
A. Miller (World Resources Inst.)
J. Ogden (Princeton University)
B. Patel (NJ Department of Energy)
F. Robson (United Technologies)
R. Socolow (Princeton University)
H. Solganick (Atlantic City Elec.)
S. Stephanidis (Allison Gas Turb.)
M. Tully (NJ Natural Gas)
J. Tuzson (Gas Research Institute)
R. Williams (Princeton University)
J. Wilson (Elizabethtown Gas)
D. Wood (International Power Tech.)
D. Yosh (Jersey Central P & L)

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Workshop Program

Date: Thursday, April 3, 1986

Place: M. Herbert Eisenhart Conference Room
Energy Research Laboratory
Engineering Quadrangle, Room G-201
Princeton University
Princeton, New Jersey

Agenda:

8:15 WELCOMING
- Robert Socolow, Director
Center for Energy and Environmental Studies

INTRODUCTIONS

OVERVIEW OF THE TECHNOLOGY AND INSTITUTIONAL ISSUES
- Robert Williams, Senior Research Physicist
Center for Energy and Environmental Studies

AGENDA AND GOALS OF THE WORKSHOP
- Eric Larson, Research Staff
Center for Energy and Environmental Studies

9:00 STATUS OF DEVELOPMENT WORK ON CENTRAL STATION STIGs
Presentation: Clint Ashworth, Supervising Mechanical Engineer
Pacific Gas and Electric Company
Panel: Clint Ashworth, Jerry Burkett, William Flye, Richard Foster-Pegg (M)*

10:00 STIGs VS COMBINED CYCLES
Presentation: Wieble Alley, Senior Energy Applications Engineer
Arkansas Power and Light Company
Panel: Wieble Alley, Jerry Burkett, Fred Robson, John Tuzson (M)

11:00 WATER QUALITY REQUIREMENTS
Presentation: George Cain, Mechanical Technology, Inc.
Panel: Clint Ashworth, George Cain, William Flye (M), Ralph Kidder

11:30 O&M COSTS
Presentation: Charles Graham, Dow Chemical Company (retired)
Panel: Wieble Alley (M), Don Brown, Charles Graham, David Yosh

* (M) indicates panel moderator.

1:30 OPERATING AVAILABILITY

Presentation: G. Michael Curley, Senior Engineer
North American Electric Reliability Council

Panel: G. Michael Curley, Charles Graham (M), Steve Stephanidis, Don Wood

2:00 LONG-TERM RELIABILITY

Presentation: Ralph Kidder, Senior Project Engineer
Allison Gas Turbine Division, General Motors

Panel: G. Michael Curley (M), Ralph Kidder, Charles Graham,

2:30 COAL GASIFIERS AND STIGs

Presentation: James Corman, Corporate Research & Development
General Electric Company

Panel: Wieble Alley, Clint Ashworth (M), James Corman

3:30 INSTITUTIONAL ISSUES

Presentation: Mike German

Panel: Ken Deffeyes, Gary Edinger, Nicholas Esposito, Steven Gabel, Mike German, Bruce Grossman, Edward Linky, Bharat Patel, Howard Solganick, Bob Williams (M), Joe Wilson

4:30 CLOSING COMMENTS

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Section 3

Perspective of the Organizers

3.1. Motivation for the Workshop

Gas turbines used today by utilities are relegated to peaking duty because of their low efficiency and need for high-cost fuel, but advanced gas turbine powerplants that could be used by utilities for baseload and load-following purposes are commercially ready or nearly so. Relative to coal and nuclear power systems these technologies offer a number of advantages:

- higher thermal efficiency
- lower capital costs
- smaller sizes
- shorter construction times
- lower consumptive water requirements
- less air pollution.

A variety of advanced gas turbine technologies* offering such advantages (Table 3.1) would be able to provide electricity at less total cost than new coal or nuclear plants, even when fired with costly natural gas. It would also be cost-effective to replace existing gas-fired steam-turbine plants with new plants based on some of these advanced gas turbines. The modest size and short lead-times of these gas turbine power plants make them well suited for utility planning in the new era of uncertain future demand. And these technologies would have the flexibility to be shifted from natural gas to gas derived from coal, if natural gas becomes too costly.

Such a favorable outlook for gas turbine based central station power generation is largely due to the continuing advances in gas turbine technology driven by strong military and commercial aircraft markets and

* See Appendices A-C for descriptions of the alternative gas turbine technologies considered in this section of the report.

Table 3.1. Comparison of Central Station Power Generating Technologies.[a]

	Full-Load Efficiency (% HHV)	Installed Capital Cost (1985$/kW)	Capacity (MW)	Time to Install (years)[b]
Nuclear	32	2000	1200	11
Coal	34	1236	2 x 500	9
Gas Turbine w/E-R[c]	40	275	150	3
Combined Cycle[d]	41	534	2 x 250	4
Advanced Combined Cycle[e]	45	565	2 x 300	4
Intercooled STIG[f]	47	450	110	3
Turbocharged STIG[g]	48	374	153	3

(a) See notes to Fig. 3.1 for sources unless otherwise indicated.
(b) Installation times are from [1] unless otherwise noted.
(c) Performance of the evaporative-regenerative (E-R) gas turbine is from Appendix C, for a turbine inlet temperature of 2190°F. The construction time is estimated to be the same as that for a peaking gas turbine.
(d) For a turbine inlet temperature of 1950°F [1].
(e) For a turbine inlet temperature of 2200°F [1].
(f) For a turbine inlet temperature of 2470°F [2]. The installation time is estimated from [2]
(g) Performance figures from Appendix B are for a turbine inlet temperature of 2200°F and are still under review. The ratio of the capital cost of the Turbocharged STIG to that of the combined cycle from Appendix B has been multiplied by the capital cost given in this table for the combined cycle to give a cost for the Turbocharged STIG that is consistent with the other figures given here.

substantial Department of Defense support for gas turbine R&D.

Until recently the fruits of these developments have been little exploited for stationary power applications. However, the doubling of the real industrial electricity price over the last decade and the passage of the Public Utility Regulatory Policies Act of 1978 have fueled rapid growth of cogeneration capacity in the US. Nearly half of this capacity is natural gas-fired (Table 3.2), and over half of all new gas-fired capacity is accounted for by gas turbines. This strong cogeneration market for gas turbines has created interest in a wide range of modifications of simple gas turbine cycles which dramatically increase the attractions of gas turbines -- not just for cogeneration markets but for central station power applications as well.

Table 3.2. Estimated Cogeneration Capacity in the US (in MW).[a]

REGION	All FUELS			GAS-FUELED		
	Existing[b]	Planned	Total	Existing[b]	Planned	Total
New England	872	1,578	2,450	13	104	117
Middle Atlantic	1,576	2,222	3,798	64	774	838
South Atlantic	3,048	1,980	5,028	267	68	335
East North Central	4,256	391	4,647	145	102	247
East South Central	1,110	210	1,320	77	38	115
West North Central	834	167	1,001	282	15	297
West South Central	9,693	5,374	15,067	8,466	4,007	12,473
Moutain	1,004	491	1,495	218	274	492
Pacific	2,321	5,163	7,484	1,234	3,604	4,838
TOTAL	24,714	17,576	42,290	10,766	8,986	19,752

(a) From [3].

(b) Includes plants built, under construction, and ordered.

What is striking about these opportunities is that most can be realized with only relatively minor modifications of existing gas turbines. That large performance improvements can be realized with so little development effort is to a large degree due to the fact that many of these cycle modifications are largely irrelevant for aircraft applications, where most gas turbine innovations have been taking place.

Advanced versions of the steam-injected gas turbine (STIG) were singled out from other advanced gas turbine concepts for focussed attention at this Workshop because preliminary analysis suggests that advanced STIG technologies [in particular, the intercooled steam-injected gas turbine, (ISTIG)] may be more attractive than other advanced gas turbine systems (see Section 3.2).

Steam injection aimed at producing more power at higher electrical efficiency is already a well-established concept for use with aircraft-derivative gas turbines in cogeneration applications. Several patents are held by International Power Technology, Inc. of Palo Alto, California for their Cheng-cycle cogeneration system based on the Detroit Diesel Allison 501-K gas turbine, the first STIG system to be commercialized. Six Cheng-cycle plants are now operating or being installed in California [4]. One STIG system based on the General Electric LM-5000 has been operated in California, and at least another four units have been ordered [5].

In contrast to the cogeneration situation, there appears to have been a cooling of interest in the STIG technology for central station powerplants, after a flurry of activity in the early 1980s. The major purpose of the Princeton Workshop on Steam-Injected Gas Turbines for Central Station Power Generation was to try to clarify why STIG development aimed at central station applications is not proceeding at a faster pace. In particular the Workshop was oriented toward understanding better the extent to which technical problems, competition from other advanced gas turbine concepts (or lack thereof), and also institutional issues were inhibiting the pace of development of ISTIG, which appears to be technically and economically the most attractive central station gas turbine powerplant identified to date:

o The thermal efficiency of ISTIG is expected to be very high -- 47%

(corresponding to a heat rate of 7260 BTU/kWh on a HHV basis) -- in a 110 MW plant, compared to only 34% for a typical new and much larger subcritical steam plant burning bituminous coal and having wet limestone flue gas desulfurization [1].

- The ISTIG has a low capital cost, estimated to be in the range $400 [6] to $500 [2] per kW, installed. This compares to some $1200 or more for new coal plants [1] and $2000 [7] or more for new nuclear plants.

- With high efficiency and low capital cost, the ISTIG would produce electricity at a total cost significantly less than that for new coal or nuclear plants and less also than that for other advanced gas turbine power plants (Fig. 3.1).

3.2. A Preliminary Cost/Benefit Analysis of ISTIG

A detailed comparision of ISTIG with coal plants is particularly instructive. Table 3.3, which compares the lifecycle costs of ISTIG plants and coal-fired steam-electric plants for alternative fuel price growth rates, shows that lifecycle savings of $100 to $500 million per GW of coal capacity replaced with natural gas fired ISTIG plants would result with natural gas price growth rates up to 3 percent per year. (For comparison, the American Gas Association projects that between 1990 and 2000 the gas price for electric utilities will increase at an average rate of 1.5% per year [9].)

For natural gas price escalation rates of more than 4% per year the lifecycle savings advantage of natural gas fired ISTIGs would disappear. However, with such high escalation rates a switch to synthetic gas would probably be desirable at some time during the life of the plant. Table 3.3 also shows the lifecycle savings for ISTIG for the case where a switch to synthetic gas from coal is made at the time the synthetic gas becomes cheaper than natural gas. In this case the lifecycle savings for ISTIG are $200 to $300 million per GW of coal-based steam-electric capacity

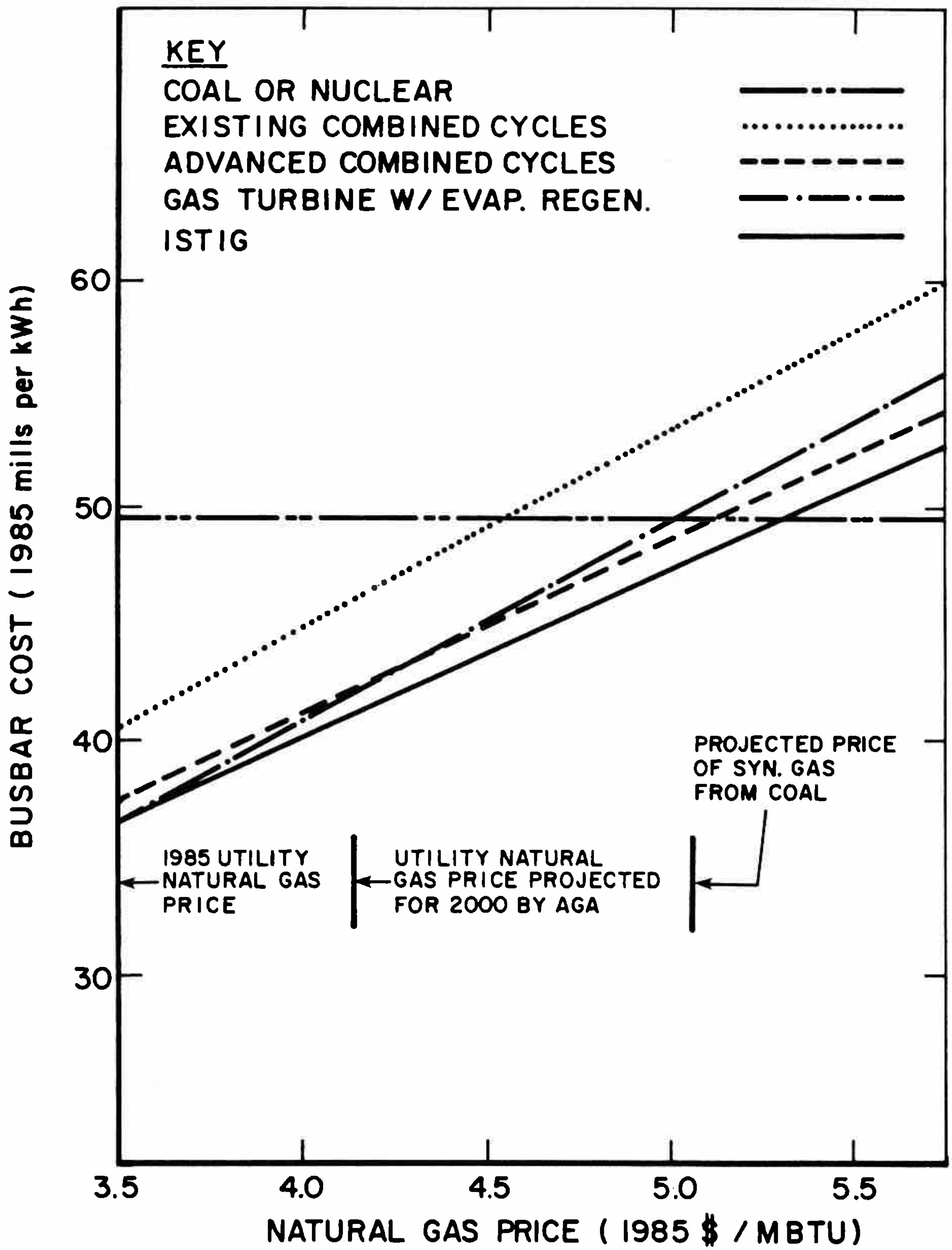

KEY
COAL OR NUCLEAR
EXISTING COMBINED CYCLES
ADVANCED COMBINED CYCLES
GAS TURBINE W/ EVAP. REGEN.
ISTIG
60
50
40
30
BUSBAR COST (1985 mills per kWh)
PROJECTED PRICE OF SYN. GAS FROM COAL
1985 UTILITY NATURAL GAS PRICE
UTILITY NATURAL GAS PRICE PROJECTED FOR 2000 BY AGA
3.5
4.0
4.5
5.0
5.5
NATURAL GAS PRICE (1985 $ / MBTU)

Fig. 3.1

Assumptions Relating to the Construction of Fig. 3.1

A 10% real discount rate and a 30 year plant life are assumed for all cases. Average capacity factors are assumed to be 70% for coal and nuclear systems and 80% for gas turbine systems. All taxes and tax credits are neglected. Costs from different sources are converted to 1985 $ using the GNP deflator.

The average price of natural gas to utilities in the first 9 months of 1985 was $3.50/MBTU [8]. The AGA has projected an average price of natural gas to electric utility customers in 2000 of $4.13/MBTU [9]. The EPRI has estimated the cost of Texaco-based medium BTU gas from coal to be ($2.12 + P_c/0.65) per MBTU, where P_c is the cost of coal in $/MBTU [10]. The price indicated on the figure is for coal @ $1.91/MBTU, the same price as that assumed for steam coal plants.

For a 1200 MW (e) nuclear plant the installed capital cost and the O&M costs are assumed to be $2000/kW and 6.7 mills/kWh respectively [7]. The fuel cycle cost is assumed to be 8.2 mills/kWh [11]. The total busbar cost is thus 49.5 mills/kWh.

For a 2-unit [2 x 500 MW (e)] bituminous coal-fired, subcritical steam plant with wet limestone flue gas desulfurization the installed capital cost and the O&M costs are assumed to be $1236/kW and 8.7 mills/kWh, respectively, and the average heat rate is assumed to be 10,150 BTU/kWh [1]. The total busbar cost is thus 30.1 + 10.15 x P_f mills/kWh, where P_f is the fuel price, in dollars/MBTU. For the figure, the coal price is chosen to be $1.91/MBTU, so as to make the coal and nuclear busbar costs equal.

For a 2-unit [2 x 250 MW (e)] conventional combined cycle power plant the installed capital cost and the O&M cost are assumed to be $534/kW and 2.56 mills/kWh, respectively, and the heat rate is assumed to be 8600 BTU/kWh [1]. The total busbar cost is thus 10.6 + 8.6 x P_f mills/kWh.

For a 2-unit [2 x 300 MW (e)] advanced combined cycle power plant the installed capital cost and the O&M cost are assumed to be $565/kW and 2.56 mills/kWh, respectively, and the average heat rate is assumed to be 7520 BTU/kWh [1]. The total busbar cost is thus 11.1 + 7.52 x P_f mills/kWh.

For a 150 MW (e) gas turbine with evaporative regeneration, the installed capital cost and the heat rate are estimated to be $250-$300/kW and 8578 BTU/kWh, respectively [12]. For the figure it is assumed that the capital cost is $275/kW and that the O&M cost is 2.56 mills/kWh (the same as for the combined cycle). The total busbar cost is thus 6.7 + 8.578 x P_f mills/kWh.

For the 110 MW (e) intercooled steam-injected gas turbine the installed capital cost is estimated to be in the range $400/kW [6] to $500 per kW [2]. For the figure it is assumed that the capital cost is $450/kW. The heat rate is estimated to be 7260 BTU/kWh [13]. The O&M cost is estimated to be 4.33 mills/kWh or 1.7 times that for the combined cycle [2]. The total busbar cost is thus 11.1 + 7.26 x P_f mills/kWh.

Table 3.3. Levelized Lifecycle Busbar Cost Comparison of Coal/Steam vs. ISTIGA and ISTIGB, for Plants Entering Service in 1990[a,b]

Price Escalation Rate (% per year)		Busbar Cost (1985 mills/kWh)			Lifecycle Savings from Installing ISTIGs Instead of a 1 GW_e Coal Plant[c] (million 1985 dollars)		Year of Switch to Syn. Gas from Coal
Coal	Natural Gas	Coal	ISTIGA	ISTIGB	ISTIGA	ISTIGB	(ISTIGB)
0	1	48.4	39.8	-	497	-	-
0	2	48.4	42.8	41.9	324	376	2005
1	2	50.2	42.8	42.6	428	439	2012
0	3	48.4	46.2	43.0	127	312	2000
1	3	50.2	46.2	44.4	231	336	2003
2	3	52.2	46.2	45.4	347	393	2008
0	4	48.4	50.2	43.8	-104	266	1998
1	4	50.2	50.2	45.4	0	278	1999
2	4	52.2	50.2	47.0	116	301	2001
0	5	48.4	54.9	44.4	-376	231	1996
1	5	50.2	54.9	46.0	-278	243	1997
2	5	52.2	54.9	47.9	-156	249	1998

(a) For initial year coal and natural gas prices of \$1.8/MBTU and \$3.6/MBTU, respectively. The cost parameters for coal and ISTIG plants are those presented in the notes to Fig. 3.1.

(b) In the ISTIGA scenario, natural gas is the fuel used throughout the life of the plant. In the ISTIGB scenario the ISTIG plant is switched from natural gas to synthetic gas derived from coal when the natural gas price reaches the cost of producing gas from coal with the Texaco process, estimated by EPRI [10] to be $(\$2.12 + P_c/0.65)$/MBTU, where P_c is the cost of coal in \$/MBTU. After the switch the fuel cost is assumed to increase only to the extent that the cost of the coal feedstock continues to escalate.

(c) Future savings (discounted to present value using a 10% real discount rate) for the 30 year life of a 1000 MW coal power station.

displaced, for all natural gas price escalation rates.* The flexibility to switch to synthetic gas makes the lifecycle busbar cost of ISTIG quite insensitive to the natural gas price escalation rate.

The gasification route to coal utilization makes it possible to produce electric power cost-effectively because the high cost of synthetic gas can be more than offset by the high efficiency and low capital cost of the gas turbine power generating system. In addition, gasification is an attractive long term route to coal utilization because of the prospect of low air pollution emissions from the combined gasification/power generation unit, as indicated by the comparision in Table 3.4 of the measured emissions for the Coolwater Integrated Gasification Combined Cycle Power Plant Demonstration Project in southern California with EPA New Source Performance Standards.

For the many utilities which have no plans for expanding generating capacity in the rest of this century this calculation may not be of immediate interest. However, ISTIG may still be of interest to utilities with adequate capacity which now use natural gas inefficiently. Nationwide some 300 billion kWh per year of electricity are produced in natural gas-fired steam plants having an average heat rate of 10,770 BTU/kWh [8]. In most instances it would be worthwhile to replace these existing plants with ISTIG units because the total cost of the ISTIG plants would be less than the operating costs of the existing plants. Replacing all gas-fired steam-

* If the combined gasification/power generating unit were optimized as a system, the system performance would probably be considerably better than that indicated here for the ISTIGB scenario. The coal-pile-to-busbar conversion efficiency for the Texaco gasifier/ISTIG plant assumed for the Table 3.3 calculations is about 31%. At the Workshop Jim Corman from GE showed that the coal-pile-to-busbar cost of an optimized ISTIG/air-blown gasifier system would be 42%.

Table 3.4. Air Pollution Emissions Vs. EPA New Source Performance Standards For The Coolwater IGCC Demonstration Power Plant[a]

	Measured Emissions[b]	EPA New Source Performance Standards
SO_2	95% removal, 0.033 lb/MBTU	90% removal (max = 1.2 lb/MBTU)
NO_x	0.061 lb/MBTU	0.60 lb/MBTU
Particulates	0.001 lb/MBTU	0.03 lb/MBTU

(a) The Coolwater plant produces 94 MW (net power) at an average heat rate (coal pile to busbar) of 11,300 BTU/kWh, using the Texaco gasifier. If the Texaco gasifier were used with an advanced combined cycle plant (@ 500 MW) a heat rate of 9000 BTU/kWh is expected.

(b) For Utah (SUFCO) design coal [14].

electric power generation in the US with new ISTIG units would require nearly 400 ISTIG units, for a total new investment of some $19 billion. But this investment would result in a lifecycle savings (net of this investment) amounting to some $10 to $20 billion, depending on the natural gas price escalation rate (Table 3.5). This investment would free up natural gas supplies for other purposes equivalent to 1/2 million barrels of oil per day. The freed-up gas supplies would be enough to provide space heating for 13 million homes or support an additional 26 GW(e) of ISTIG generating capacity, if new generating capacity were needed.

Of course one could do almost as well by replacing existing gas-fired steam-electric plants with new advanced gas turbine/steam turbine combined cycle (ACC) power plants. In particular the combined cycle based on the new General Electric Frame 7F industrial gas turbine is expected to have an efficiency of 45% and a capital cost only slightly higher than that of ISTIG (Table 3.1).

Table 3.5. Lifecyle Savings From Replacing Existing Natural Gas Fired Steam-Electric Power Generation With ISTIG or ACC Units

Natural Gas Price Escalation Rate (% per year)	Incremental Generation Cost (1985 mills/kWh)[a]			Lifecycle Savings From Displacing Existing Gas/Steam Generation With Advanced Gas Turbine Technologies (billion 1985 dollars)[b]	
	Existing	ISTIG	ACC	w/ISTIG	w/ACC
0	41.3	37.2	38.2	10.3	7.9
1	44.3	39.3	40.3	12.8	10.3
2	47.7	41.6	42.7	15.7	12.9
3	51.5	44.1	45.3	18.8	15.8
4	55.7	47.0	48.3	22.3	19.1

(a) The costs for ISTIG and advanced combined cycle (ACC) plants are long run incremental costs (levelized capital cost plus O&M cost plus fuel cost), based on the cost data presented in the notes to Fig. 3.1. For existing steam plants the costs are short run marginal costs [O&M cost (assumed to be 2.5 mills per kWh) plus fuel cost (for the US average heat rate in gas-fired plants, some 10,770 BTU/kWh)].

(b) Arising from the displacement of the current level of natural gas-based power generation with steam plants in the US (300 billion kWh per year), over a 20 year period, with future savings discounted using a 10% discount rate.

A significant difference between the ACC and the ISTIG is that the former is commercially available, while the later requires perhaps a $100 million of R&D to bring to market. Would it be worthwhile to carry out this development effort for a gain of only 2 percentage points in thermal efficiency?

While the full answer to this question involves consideration of may issues -- including reliability, flexibility, environmental controls, etc., one important parameter bearing on the answer is the net economic benefit resulting from the improved efficiency. A quantification of this benefit can be gleaned from a comparision of the lifecycle savings for the alternative cases where existing steam plants are replaced by ACC and ISTIG plants.

As shown in Table 3.5, the lifecycle savings are \$2.5 to \$3 billion more with the ISTIG than with the ACC. This calculation indicates that the R&D would be socially worthwhile, yielding a benefit/cost ratio of 25 or 30 to 1.

Such calculations indicate the great value of continuing the quest for improved efficiency and lower capital costs in gas turbine technology for stationary power applications.

3.3. Workshop Objectives

One objective of the Workshop was to clarify technical issues related to the ISTIG -- thermal efficiency, water quality requirements, environmental concerns, O&M costs, operating availability, long-term reliability, performance on gasified coal, etc. -- and how ISTIG would compare with other advanced gas turbine concepts in these regards.

A second objective was to better understand important non-technical issues bearing on the commercialization of ISTIG: the natural gas supply outlook, the Powerplant and Industrial Fuels Use Act (FUA), electric utility interest in gas turbines for purposes other than peaking, and gas turbine vendor interests in and capabilities for developing these utility markets.

3.4. Findings of the Workshop

From the Workshop discussions, presented in detail in Section 4, a number of technical findings emerged, along with a picture of the present and future gas supply situation, and a better understanding of relevant institutional issues relating to the development of ISTIG and other advanced gas turbine technologies.

3.4.1 Technical

The overall sense of the Workshop participants was that there were no significant technical problems that would inhibit development of an ISTIG machine for central station power generation.

In addition, a number of particularly attractive features of ISTIGs were identified:

- The ISTIG would be very efficient: 47% (higher heating value). This is considerably higher than the efficiencies of both steam-electric plants (32-34%) and gas turbine/steam turbine combined cycle power plants now in use (40-41%).

- Peak efficiency would be reached in a relatively small plant, 110 MW, compared to the next most efficient system, the advanced combined cycle, which would reach peak performance in a plant about twice this size.

- The ISTIG would be a simpler system compared to steam-electric plants and combined cycles (e.g., no steam turbine or cooling tower would be required).

- The ISTIG would consume significantly less water per unit of power produced relative to steam-electric plants.

- Maintenance would be facilitated because the ISTIG would be based on an aircraft-derivative engine, the modular design of which permits more rapid replacements and repairs to be made in comparison to heavy duty industrial turbines. Operating availabilities could be expected to be 90% or higher, based on industry's experience with STIG cogeneration systems and on the data collected by the North American Electric Reliability Council on availabilities of aircraft-derivative gas turbines currently used for central station power generation.

- Industrial experience with aircraft-derivative gas turbines in baseload applications suggests that ISTIG would have relatively low O&M costs. Long-term maintenance costs for several baseloaded aircraft-derivative gas turbines operated by DOW Chemical have averaged 2-3 mills per kWh.

- Water used in ISTIG systems would have to be treated at least to the standards required for low pressure boilers, but no further than the standards required for water injected for NO_x control in today's peaking gas turbines. The NO_x-control standard may be an overly conservative constraint. Since only small amounts of water are used for NO_x control, water treatment does not represent a major operating cost in conventional gas turbine systems. Thus, there has been little incentive to minimize water treatment. Testing and data collection are required to determine the minimum acceptable water treatment for ISTIG systems.

- An ISTIG is expected to have very low NO_x emissions without using special NO_x control technology (such as Selective Catalytic Reduction), due to the injection of steam. Currently operating STIG cogeneration plants have met or exceeded NO_x emission standards in various parts of California, the state with the strictest NO_x standards.

- Among several advanced gas turbine systems that have been evaluated for operation on gasified coal, ISTIGs appear to be better suited than alternatives. In evaluations by General Electric, it was found that a gasifier-LM-5000/ISTIG would produce about 105 MW of electricity at 42.1% efficiency (higher heating value). The Frame 7F combined cycle operating on gasified coal would yield optimum performance in a much larger unit size, 500 MW, and at a lower efficiency, 38.5%.

Despite these many attractive features of ISTIG, alternative gas turbine technologies would be competitive or nearly competitive, with regard to particular attributes:

- The Frame 7F combined cyle, an advanced combined cycle which is commercially ready, is expected to have an efficiency almost as high (45%). And while total make-up water requirements for ISTIG and the Frame 7F would be comparable, make-up for the ISTIG requires treatment to the standards required for low pressure boilers, while that for the combined cycle is lower quality condenser cooling water.

- Preliminary calculations performed by Richard Foster-Pegg (Appendix B) indicate that the turbocharged STIG (a concept which would permit extending the use of steam-injection to industrial gas turbines) may be about as efficient as the ISTIG (Table 3.1).

- A utility scale gas turbine with evaporative regeneration (ER) under development at Westinghouse (Appendix C), though not as efficient as ISTIG, would be simpler and even less capital-intensive (Table 3.1). Because it does not require a boiler, a gas turbine with ER would also requires much less water treatment than the ISTIG.

This list of alternative gas turbine concepts should not be considered definitive. The list can be expected to grow, as opportunities for regeneration, reheat, intercooling and other modifications are explored further.

3.4.2. Natural Gas Supply Outlook

A utility strategy which involves initial firing of advanced gas turbine generating plants with natural gas makes the most sense if there are reasonable expectations that natural gas will be available and affordable for a number of years. If the natural gas supply outlook were as bleak as in the mid-1970s, when for several years natural gas reserve additions fell far short of production (Fig. 3.2), natural-gas firing of utility turbines would make no sense.

The near term outlook for natural gas has changed dramatically, however. The decontrol of prices for "new" natural gas supplies has led to a situation where reserve additions have been comparable to production for the last several years (Fig. 3.3). In fact, the US is in the 7th year of a "gas bubble" which was originally envisaged to last 18 months and which is expected to last a few more years.

Looking beyond the next few years, the gas supply outlook becomes less clear. On the one hand, the American Gas Association's latest forecast [9] is that domestic natural gas supplies from the lower 48 states will increase slightly, from 1985 to 2000, and that the price paid for natural gas by electric utilities will decline slightly until 1990, after which it will rise slowly, reaching the 1985 level near the turn of the century. In sharp contrast, the US Department of Energy, less sanguine about the gas supply outlook, projects sharp increases in the natural gas price in the period near the turn of the century [16].

For the long term, the Potential Gas Committee of the Potential Gas Agency estimates that remaining ultimately recoverable natural gas (reserves plus estimated additional probable, possible, and speculative resources) in the US (lower 48 states plus Alaska) are equivalent to about a 50 year supply at the present consumption rate [17].

At the Workshop Michael German of the American Gas Association argued that this estimate should not be regarded as hard and fast. He felt that as long as there are no price controls constraining gas-finding efforts, there will probably be continuing upward revisions of estimates of

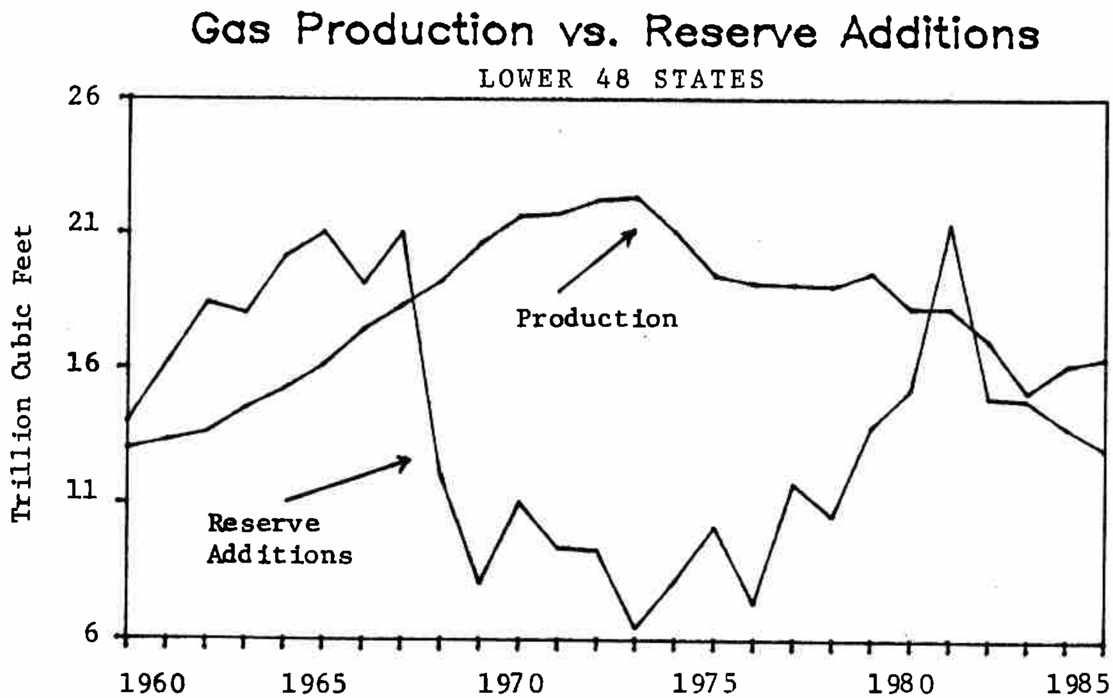


Fig. 3.2 (From [15])

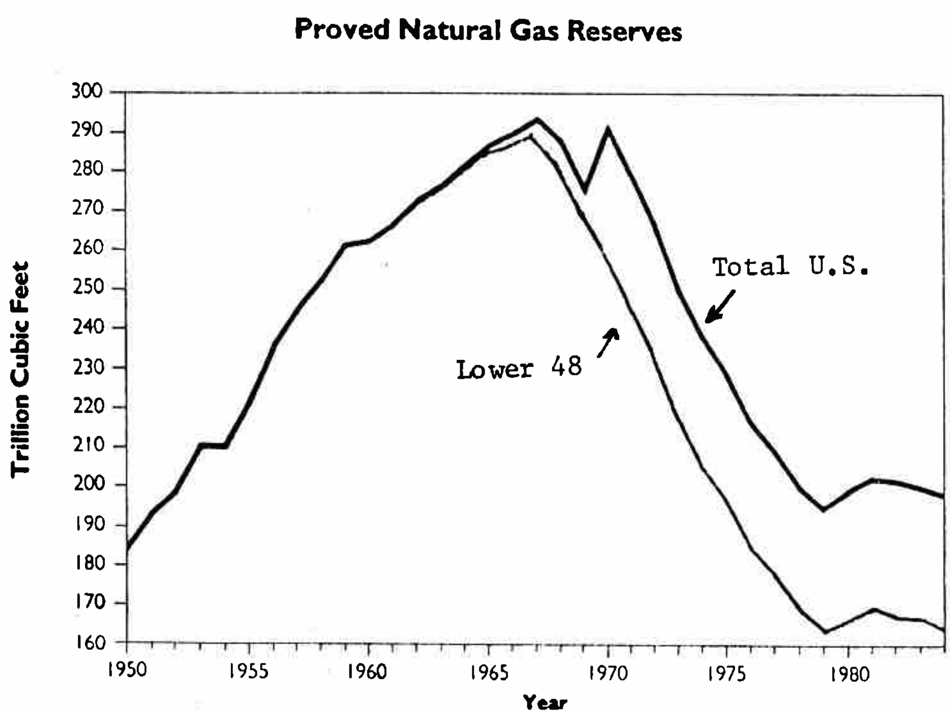


Fig. 3.3 (From [15])

remaining ultimately recoverable gas resources. In support of this thesis he pointed out that the Potential Gas Committee's estimate of potential additions to reserves for the lower 48 states was about the same in 1984 as it was in 1966, despite the fact that in the intervening 18 year period natural gas consumption in the US amounted to more than half of the 1966 estimate of remaining ultimately recoverable resources! He said that there was certainly no impending <u>physical</u> constraint on gas supplies in this time frame; indeed, the physical amount of gas in place amounts to more than a thousand year supply, if geopressurized gas resources are included.

Of course, all prognostications about gas supply in the long term must be regarded as highly speculative. Much less speculative is the prospect that gas supplies can and will be substantially expanded on "the demand side." The amount of remaining gas estimated by the Potential Gas Committee could actually last considerably longer than 50 years -- for two reasons.

First, there is an ongoing shift within the industrial sector of the US economy away from the processing of basic materials toward inherently less energy-intensive fabrication and finishing activities. Coupled to relatively modest price-induced conservation efforts, this structural shift implies that industrial energy use (and thus probably natural gas use as well) will decline in the period to the year 2000 [18].

Second, there are also many opportunities for using natural gas more efficiently in other sectors. For example, emphasis on energy efficiency improvements in single family dwellings <u>with technology that is currently available commercially and cost-effective</u> would lead to a reduction in natural gas use in this sector equivalent to some 3/4 million barrels of oil per day in the period 1980-2000, despite a projected increase in this period of some 7.5 million new households that would use gas for space heating purposes [19]. We have already shown how the replacement of electricity production based on existing gas-fired steam-electric plants with ISTIG units would reduce gas use for electricity generation by an amount equivalent to some 1/2 million barrels per day.

To a considerable extent these opportunities for conservation imply that the problem of gas supply uncertainty is self-correcting. If the lower estimates of supply prove to be closer to the truth, the resulting higher prices will force a faster pace of adopting more energy-efficient technologies, leading to a stretching out of the available supply. On the other hand, if the higher supply estimates prove to be closer to the mark, the country would be making a mistake by prematurely committing huge resources to more costly energy supply technologies.

3.4.3. Institutional

Several institutional constraints inhibiting the development of ISTIG and related technologies were highlighted by Workshop discussions:

- The Powerplant and Industrial Fuels Use Act of 1978 (FUA) makes it difficult for utilities to adopt new natural gas based generating technologies.

- The present utility market for advanced gas turbine generating technologies would be uncertain even if FUA were repealed, because of a general utility reluctance to build any new generating capacity.

- While the utility gas turbine market is uncertain, the military market for aircraft turbines is strong, so that military applications are the focus of development efforts of gas turbine manufacturers who make aircraft and aircraft-derivative turbines.

- Domestic competition is weak in the area relating to advanced aircraft-derivative turbines suitable for central station power generation.

The Powerplant and Industrial Fuels Use Act. As a response to the gloomy outlook for natural gas supplies in the mid-1970s, Congress in 1978 passed the Powerplant and Industrial Fuels Use Act. One of the FUA provisions barred utilities from using natural gas in new power plants. Another required them to shift existing power plants off gas by 1990. Subsequently the second provision was repealed.

While it is possible to get exemptions from the FUA constraint on new plants (there have already been 100 exemptions to the Act to date), the Act nevertheless is a major deterrent to utility interest in advanced gas turbine power generating technologies.

Should the law be repealed? As indicated earlier, the outlook for natural gas supplies over the next several years is certainly much different than it was at the time the Act was passed, although the long term outlook has changed very little.

The case for repeal is suggested by general economic arguments that the market is an inherently more efficient allocator of scarce resources than administration. The current FUA rules relating to utilities certainly underscore this judgment, as it is now legal for utilities to use gas inefficiently in existing plants but illegal to use it efficiently in new plants!

Whatever the shortcomings of FUA, the important public policy issue that remains is how to cope with the uncertain long term gas supply outlook -- how to capture the economic and environmental benefits of natural gas fueling, in the face of the possibility that gas may become costly and scarce at some indeterminate time in the future.

A gas turbine based power generating strategy is well-suited for coping with this uncertainty. For the near term the substantial gas savings that would result from replacing gas-based steam electric plants with efficient gas turbines would help prolong the gas bubble, while simultaneously reducing electricity rates. The strategy would also be economically efficient in the long term, even if gas supplies should become very tight, because of the inherent flexibilty to shift to synthetic gases and still produce electricity at costs that would be competitive with electricity from conventional coal and nuclear plants.

The availability of advanced gas turbine concepts like ISTIG thus provides support for a judgment that FUA should be repealed. In any case, at the Workshop Michael German expressed his belief that FUA would be repealed, probably in 1986.

The Uncertain Utility Market for Advanced Gas Turbines. Even if the FUA were repealed, a strong utility market for advanced gas turbine power generating technologies may be slow to develop.

In part the problem is that slow electrical load growth, excess generating capacity, and the now large financial risks of new construction have made most utilities reluctant to commit to any new generating capacity additions.

But, as we have shown, even if there is no need to expand generating capacity it would often be economical for a utility with gas-fired steam-electric generating capacity to replace that capacity with new energy-efficient gas turbine power plants. Yet utilities are generally not sufficiently motivated to do this. Even though this would lead to lower consumer _electric rates_ because of reduced fuel costs, the utility nevertheless would have to seek a _rate increase_ in order to add the new capacity to its rate base. Many utilities are reluctant to do this because of all the difficulties they have encountered in the rate-making process in recent years.

To the extent that utilities are inhibited from pursuing cost-effective retrofits because of concerns about the rate-making process, the country is missing:

- the opportunity to prolong the "gas bubble" by reducing the demand for natural gas (by some 1/2 million barrels of oil-equivalent per day, if all existing gas generation were replaced);
- the opportunity to reduce electric rates by shifting to a more economically efficient basis for generating electricity with natural gas (Table 3.5);
- the opportunity to build a new industry of power systems vendors to serve both domestic and foreign markets (the initial replacement market may be worth up to $20 billion in sales of advanced gas turbine power systems);
- the opportunity, with this new industry in place, for a utility to have installed quickly a new advanced gas turbine power system, in the event that unexpected demand growth should require new generating capacity earlier than was planned.

<u>Utility vs. Military Markets for Gas Turbines</u>. Not only is the utility market for advanced gas turbines weak, but also the vendors of aircraft-derivative gas turbines in particular are not actively trying to develop such markets -- in large part because the Department of Defense provides a steady stream of revenues by purchasing military aircraft with gas turbine engines and by supporting development of gas turbine innovations that would serve military needs. The extent of the military interest in gas turbines is indicated by the fact that DOD support for gas turbine R&D averaged some $425 million per year in the period 1976-1983 (Table 3.6). DOD budget requests are even higher for the coming years.

Ironically, the high energy performance that would be achievable with

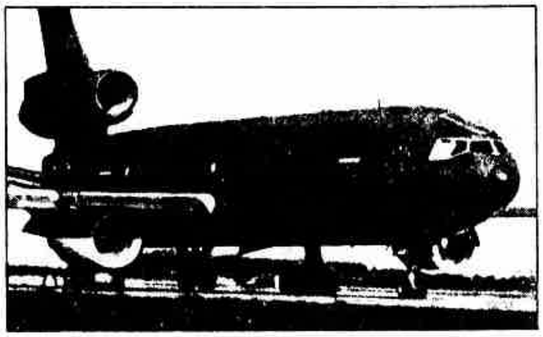
Table 3.5. Total Research, Development, Test, and Evaluation Expenditures of the US Department of Defense.

Procurement Program	FY76	FY77	FY78	FY79	FY80	F781	FY82	FY83
	(in 10^6 current dollars)[a]							
Airframes and Related Assemblies and Spares	1085.0	1166.2	1204.5	905.2	796.1	145.0	2219.5	1349.8
AIRCRAFT ENGINES AND RELATED SPARES AND SPARE PARTS	182.4	339.4	290.4	283.3	245.9	367.0	377.5	462.1
Other Aircraft Equipment and Supplies	110.9	143.2	145.7	126.5	128.8	227.2	309.3	260.3
Missile and Space Systems	2305.3	2302.4	2721.4	3063.9	3363.3	4603.2	5648.4	6443.8
Ships	242.7	303.0	248.7	296.4	305.0	253.5	327.9	408.9
Tank-Automotive	89.1	225.0	509.6	117.7	111.0	149.9	160.2	162.1
Weapons	125.8	188.4	203.0	272.6	218.9	208.4	268.5	277.9
Ammunition	108.0	97.7	101.4	149.9	201.8	292.7	278.3	297.4
Electronics and Communication Equipment	1490.9	1788.7	1764.7	1892.6	2417.4	2581.9	3534.1	4681.4
Services	1045.2	1231.9	1408.7	1357.1	1563.3	1474.4	1514.1	1635.9
All other	86.1	109.6	85.3	79.4	110.9	179.6	244.5	321.4
TOTAL	6871.4	7895.4	8683.1	8544.9	9470.4	10462.7	14882.2	16300.9
	(in 10^6 1985 dollars)[b]							
Airframes and Related Assemblies and Spares	1898.8	1935.9	1863.4	1286.3	1037.3	172.3	2479.2	1452.4
AIRCRAFT ENGINES AND RELATED SPARES AND SPARE PARTS	319.2	563.4	449.2	402.6	320.4	436.0	421.7	497.2
Other Aircraft Equipment and Supplies	194.1	237.7	225.4	179.8	167.8	269.9	345.5	280.1
Missile and Space Systems	4034.3	3822.0	4210.0	4353.8	4382.4	5468.6	6309.3	6933.5
Ships	424.7	503.0	387.4	421.2	397.4	301.2	366.3	440.0
Tank-Automotive	155.9	373.5	788.4	167.3	144.6	178.1	178.9	174.4
Weapons	220.2	312.7	314.0	387.4	285.2	247.6	299.9	299.0
Ammunition	189.0	162.2	156.9	213.0	262.9	347.7	310.9	320.0
Electronics and Communication Equipment	2609.1	2969.2	2730.0	2689.4	3149.9	3067.3	3947.6	5037.2
Services	1829.1	2045.0	2179.3	1928.4	2037.0	1751.6	1691.2	1760.2
All other	150.7	181.9	132.0	112.8	144.5	213.4	273.1	345.8
TOTAL	12025.0	13106.4	13432.8	12142.3	12339.9	12429.7	16623.4	17539.8

(a) From [20].

(b) Expressed in 1985 dollars using the GNP deflator.

ISTIG technology is, to a large degree, a direct result of this military R&D effort. The General Electric LM-5000 gas turbine, upon which the ISTIG design is based, is in turn based on the jet engine used in the Air Force's KC-10A Extender tanker/cargo plane (Fig. 3.4).



McDonnell Douglas KC-10A Extender

Fig. 3.4. (From [21])

Unfortunately, the modifications of the LM-5000 needed to convert it into an ISTIG are not directly relevant to military applications and so cannot be expected to emerge as a direct "spin-off" of the military effort -- even though the required incremental development effort is modest (some $33 million per year for 3 years) in relation to the overall military gas turbine R&D support level.

Should government actively promote R&D on utility applications for aircraft-derivative turbines? To the extent that government leaders are interested in promoting civilian spin-offs of defense R&D, the aircraft derivative turbine would seem to be an ideal candidate which could reap large rewards from a relatively modest incremental R&D support. The public rewards would be not only reduced utility rates for US electricity customers but also a more favorable foreign trade balance, if US vendors can compete successfully in potentially large foreign markets.

Competition in Aircraft-Derivative Turbine Markets. Closely related to the fact that aircraft turbine vendors are not hungry for utility turbine markets is the fact that there is little competitive pressure among vendors to develop a new high efficiency turbine system.

General Electric, the manufacturer which has done the work to date on ISTIG, lacks the stimulus needed to bring it to commercialization. GE has already made major investments to develop the Frame 7F advanced combined cycle, which would produce electricity at a cost approaching that of ISTIG (Fig. 3.1). The only other potential US manufacturer of an ISTIG machine is Pratt and Whitney, which currently does not have an active marketing program for stationary powerplants. Without assurances of substantial initial markets, neither General Electric nor Pratt and Whitney is likely to invest in the development of ISTIG.

It might be argued that with the Frame 7F available, there is no pressing need to bring still another new turbine to market at this time. Yet as Clint Ashworth from Pacific Gas and Electric pointed out at the Workshop, the Frame 7F is an industrial gas turbine, a technology for which US manufacturers are not especially advanced over a number of foreign competitors. However, the US should do well in marketing aircraft-derivative turbines in utility markets world-wide, as the US industry is the undisputed world leader in jet engine technology, thanks largely to the strong R&D support from the DOD. It would seem that an ISTIG development effort would be a promising way to secure an important niche in the increasingly competitive world markets for high technology.

Regardless of what US manufacturers do in this area, however, it is inevitable that, because it is such an attractive technology and because its development costs are so low, ISTIG or some variant of it, will be developed in the near future -- somewhere. At the Workshop Don Wood from International Power Technology (IPT) said that, after trying without success for 11 years to get General Electric to develop a utility-scale STIG machine, IPT is now working with a multi-billion dollar Japanese firm to organize financing for such an effort.

3.5. Conclusions

The Workshop has shown that there are no obvious technical obstacles to the development of ISTIG, but that it is unlikely that ISTIG will be quickly developed by US manufacturers without some kind of external support or incentive. Utility interest in ISTIG is constrained by the Fuel Use Act and by a general reluctance to build new generating capacity for either capacity expansion or capacity replacement. The low manufacturer interest in ISTIG reflects both the uncertainties about the utility market and the much more lucrative nature of military and commercial aircraft markets for gas turbines.

The Workshop and follow-up discussions also made clear that while ISTIG may be the most attractive advanced gas turbine technology identified to date, it is just one of several very promising advanced gas turbine concepts relevant to baseload and load-following utility applications that could be brought to market quickly. Because this new class of efficient, relatively small-scale, low capital cost, low polluting, fuel-flexible technologies is well-suited to the new era of uncertainty faced by utility planners, a variety of technologies should be encouraged by public policies that deal with the institutional issues that now inhibit the development of utility markets.

Development of ISTIG in particular would be important in part because it is based on an aircraft engine, for which continuing high technology innovations can be expected in the years ahead, as a result of continuing military R&D expenditures in this area. Utility spin-offs of this military R&D could be realized with modest incremental R&D support aimed at meeting unique utility requirements. In addition, since US manufacturers are undisputed world leaders in jet engine technology, it is very likely that in the area of advanced aircraft-derviative utility turbines, US vendors would be highly competitive in the world markets which are certain to become large in the years ahead.

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Section 4

Workshop Panel Discussions

4.1. Status of Development Work on Central Station STIGs

The panel consisted of Clint Ashworth (Pacific Gas and Electric), Jerry Burkett (ASEA-STAL), William Flye (Stewart and Stevenson), and Richard Foster-Pegg (independent consultant). Presentations were made by Ashworth, Burkett, and Foster-Pegg.

Clint Ashworth, Pacific Gas and Electric:* A utility sees performance and technical issues of a new central station generating technology in the context of utility need and market. Utilities are potential customers for mass steam-injected gas turbines (STIGs). What I propose to do is give a utility perspective on STIGs, touching upon expected performance and unresolved technical issues as these apply to a customer perspective.

My company first became interested in mass steam-injected gas turbines in 1975 when Prof. Dah Yu Cheng told me of his optimized version, which he calls the Cheng cycle. He obtained several patents on it which are now held by International Power Technology, Inc. I thought the concept was interesting but had no idea we would want to build new gas-fired power plants.

Since then the generation needs of utilities have changed far more than any of us expected. Load growth is down. We have thousands of megawatts contracted for from outside developers -- most of it natural gas fired. And large central station power plants of any kind seem to have become expensive, unpopular, and unneeded.

We have passed through a period where natural gas was so expensive that coal gasification has become established in utility thinking as a viable backup gas supply for central station natural gas fired power plants.

This is a key point. Coal gasification has given gas-fired generation fuel supply insurance and, in effect, restored utility confidence in new gas-fired generation as a viable central station option.

Utilities contemplating new gas-fired central station power plants usually do so with plans and provision for coal gasification add-on later, if necessary. The idea of building a natural gas fired plant and adding coal gasification later is called phased development. Utilities like the idea of phased development. It provides low cost new generation. It can be built in small plant increments. It defers the big plant investment required to use coal, but does provide the option for adding coal later. These days, with gas prices low, phased development promises large present worth savings.

The federal Fuel Use Act prohibits utilities from building new natural gas fired central stations. Presumably, this is to conserve gas. But

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* What follows is the paper Ashworth submitted in support of his oral presentation, entitled "Expected Performance and Unresolved Technical issues of Steam-Injected Gas Turbines."

regulations that restrict utilities but not others from building new gas-fired power plants coupled with low gas prices are having the effect of increasing gas use with little regard for efficient or optimal use.

Regulations -- the Fuel Use Act, PURPA, and to some extent the utility rate making process itself, threaten major erosion of both the efficient use of precious energy and capital resources and the means for providing efficiency: reasonably healthy integrated-energy-supplying utilities. Regulations have created an uneven playing field that favors spending capital and fuel resources on an ad hoc basis, generally on small scale gas-fired generating projects, without regard to what is best for society as a whole.

Looking solely at gas resource use, utilities like PGandE could save gas by burning the gas they use in more efficient new generating or cogenerating plants than by continuing to burn it in old steam plants that now have to be kept idling or partly loaded much of the time at atrocious heat rates. An argument might be made that if old gas fired steam plants had to run very much, more gas might be saved per dollar of new plant investment, up to a point, by building new efficient gas fired generation than by building plants that don't use gas, for example coal, wind, or solar power plants.

Now that coal gasification backup has given utilities a warm feeling about gas supply, they want to use gas -- but not waste it. There is considerable interest in improving gas-to-electricity conversion efficiency.

Clean gas is an easy fuel to use. Being able to think of it as an option for new generating plants opens up all kinds of opportunities for conversion efficiency improvement that were not available when harder-to-use fuel choices limited power plants to steam cycles. A gas-fired steam cycle plant is hard pressed to get efficiencies as high as 40%. Not so with other kinds of conversion cycles.

The subject of this workshop, STIG, is a very desirable advanced gas-fired generation concept, but not the only one. Combined gas turbine, steam turbine cycles are great for fuels clean enough to burn in gas turbines. They are the best commercially available technology for large clean fuel central stations -- low plant cost, efficiencies reaching into the upper 40s. Who could want anything more?

Three or four years ago, our interest was reawakened in the idea brought to us by Dr. Cheng. One thing that spurred our interest was his success in getting a startup company in business delivering small 5 MWe cogenerating plants using the concept, a model of which is shown in Fig. 4.1. Also, our analysis with input from EPRI's Art Cohn showed the General Electric LM-5000 aero-derivative gas turbine to be an excellent match for the steam-injected concept.

Before STIG came into the picture for us, we were already impressed by the exceptional efficiency of the basic aero-derivative LM-5000 gas

Fig. 4.1

turbine, whose cycle and performance are illustrated in Fig. 4.2. As a stand alone combustion turbine, its efficiency is much higher than industrial gas turbines which are designed for low pressure ratio and combined cycles. We were planning an LM-5000 without steam injection for a plant addition in downtown San Francisco.

When we first scoped a STIG for this plant, it looked like the same simple, small plant, but with higher efficiency and a larger rating, as indicated in Fig. 4.3. Now that a 49 MW first commercial version of the LM-5000 STIG is available, a STIG is the clear choice for the proposed plant expansion.

It looked to us like a fully optimized steam-injected LM-5000 might reach 55% LHV (lower heating value) efficiency (which translates to 50% on a HHV basis), while the best combined cycles appeared to us to be 47% LHV (or 43% HHV) efficient. We saw this margin of 7 or 8 percentage points of efficiency as worth the trouble to try to get it developed.

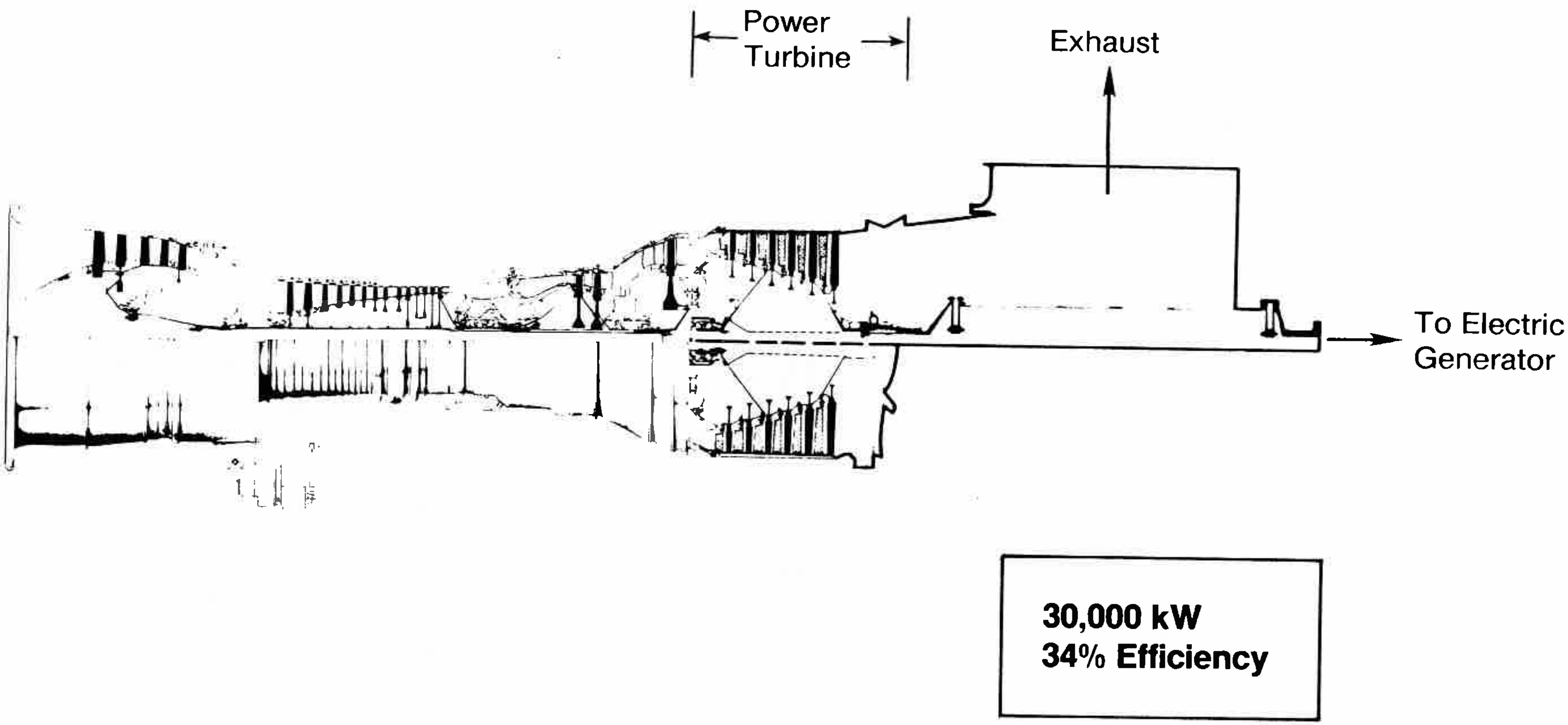
(As an aside, I wish the universities would give more thought to whether true thermodynamic efficiency really is HHV rather than LHV. Gas-fired power plant efficiency should not be penalized for inherent unavailability in the fuel. The difference between fuel HHV and LHV does not appear to be convertible to useful work but appears unavailable before the fuel even enters a power plant, except for adding heat to surroundings. When we looked at an optimized LM-5000 STIG for a solar power plant, the conversion efficiency was 55%, the equivalent of lower heating value for a fuel. Are gas fired power plants really only 9/10ths as efficient as they would be with a different source or heat?)

It occurred to us that if utilities could shift from industrial gas turbine based combined cycles to aircraft derived steam-injected gas turbines we could count on much broader-based stronger-funded development to give us further improvement in the future.

Following a lead from EPRI's Art Cohn, in May of 1983 we asked General Electric's aircraft engine people in Ohio if there was interest in scoping a mass steam-injected LM-5000.

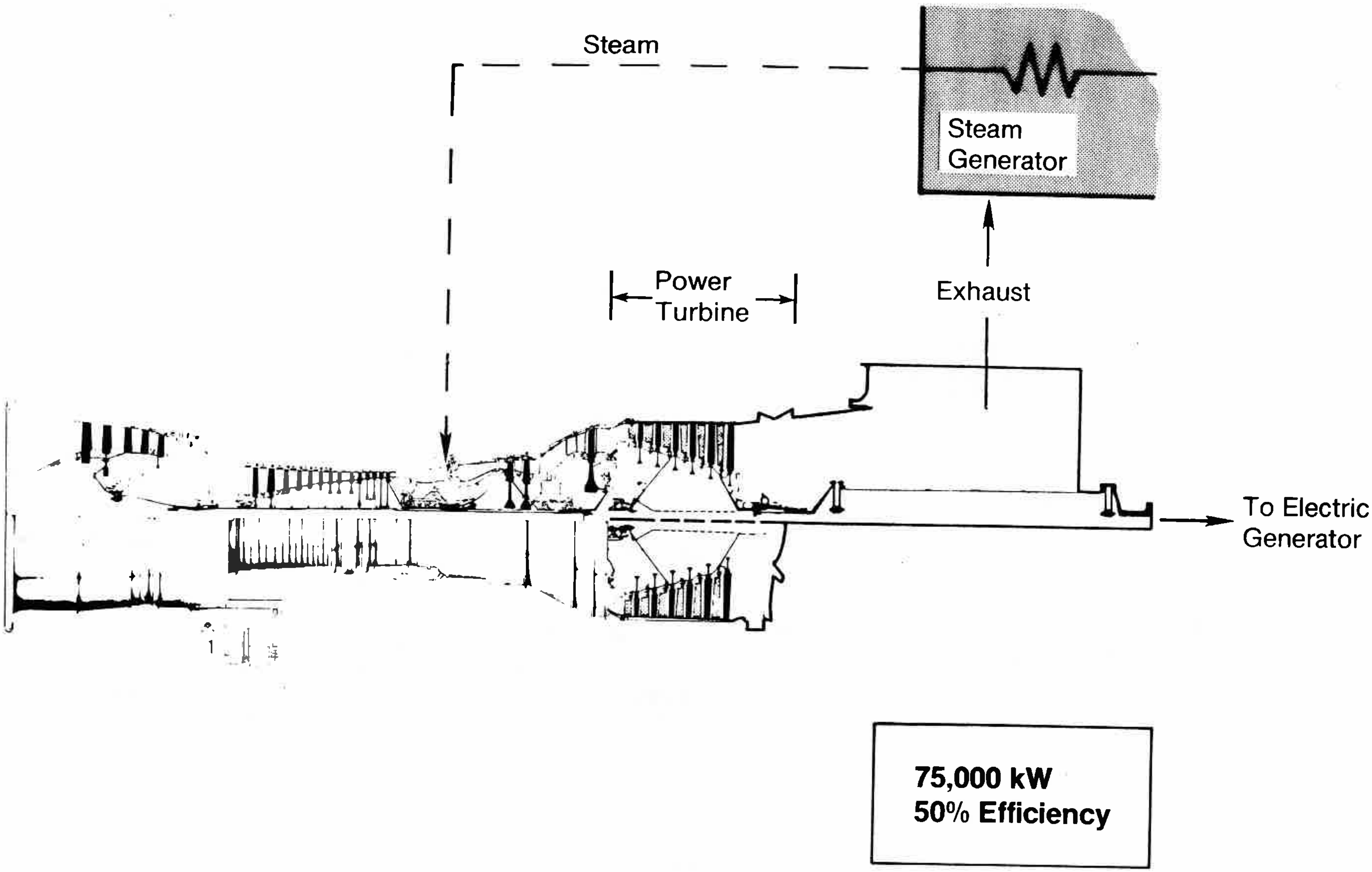
GE said they had always liked the idea of mass steam injection but they thought utilities were concerned about using up the water that would be required. We pointed out that water consumption was no greater for a STIG than for an evaporatively cooled combined cycle. Water use compared to various kinds of power plants is shown in Table 4.1.

A joint GE/PGandE scoping study was completed in the spring of 1984 and a follow-on design and further optimizing joint effort was completed in early 1985. By late 1985, just two and a half years after our initial contact with GE's aircraft engine department, GE had a minor modified STIG on the market, a unit modified for STIG operation in the field, and a first new order.



High-Technology Combustion Turbine

Fig. 4.2



High-Technology Steam-Injected Gas Turbine

Fig. 4.3

Table 4.1 Water consumption for steam power cycles with evaporative cooling.

Steam Conditions	Typical Application	Consumption (lb/MWh)
520°F/800 psi	Nuclear plant, 500-1300 MW	9,000
960/1450	Steam cycle in combined cycle	6,500
1000/1000/1800	Steam cycle in large, adv. cc.	4,940
1000/1000/2400	Small fossil plant, under 300 MW	4,580
1050/1000/3600	Medium fossil plant, 300-500 MW	4,115
1050/1025/1000/4500	Large fossil plant, > 500 MW	3,900
	Current large combined cycle (400 MW)	2,050
	Steam-injected gas turbine plant	2,100

What GE has not yet been able to get developed is the optimal design, the intercooled LM-5000 STIG, or ISTIG. To get the full promise of the ISTIG requires major modification of the LM-5000 engine. In effect, the minor modified LM-5000 STIG now on the market only went half way. Going the rest of the way will be expensive.

Utility interest was great during our scoping and design studies with General Electric. But hope for substantial utility support for getting ISTIG developed waned considerably when ISTIG fell a bit short of what we had expected and combined cycle competition proved to be a moving target.

Table 4.2 shows the shrinking competitive advantage of ISTIGs over large combined cycles. Note that when ISTIGs were first scoped, they promised to be much smaller than the most efficient combined cycles and many efficiency points better. Currently, ISTIGs are not a lot smaller, are about the same efficiency, and they are nowhere near being ready for commercial orders. I suspect that utility interest in ISTIG stimulated some of the change in combined cycles. So maybe we accomplished what we set out to do -- it just didn't happen to turn out to be STIGs.

That brings us to where things stand today. Combined cycles can give us pretty much what we hoped to get from ISTIGs.

However, combined cycles may not give us the right developmental and size scaleup trends for the future. For reasons that I won't go into here, combined cycle improvements like adding reheats to the gas cycle and the steam cycle have the effect of making the ratio of gas cycle output to steam cycle output large and the optimal plant size very large, perhaps 1000 MWe.

Table 4.2 The shrinking competitive gap.

	ISTIG	Large Combined Cycle	ISTIG Difference
Expectation, 1983-84:			
Size	75 MWe	300+ MWe	quarter the size
Efficiency	55% LHV	47% LHV	8% points better
When available (for order)	??	??	no disadvantage
Current expectation:			
Size	110 MWe	200 MWe	not a lot smaller
Efficiency	52% LHV	50% LHV	about the same
When available	??	1987	big disadvantage

And, as I have already pointed out, combined cycles use low pressure ratio industrial gas turbines that do not have the developmental resources behind them for further improvement that aircraft engine development has. I think once STIGs penetrate the utility market, they will quickly be ahead and U.S.energy supply will be better off.

There is another national interest point to make. The aircraft engine business is a rare solidly competitive U.S. heavy industry, whereas the U.S. does not have a secure position relative to foreign competition in industrial gas turbines. There is no assurance that utilities will be buying their combined cycle turbomachinery from U.S. suppliers. Unless the U.S. aircraft engine business falters in foreign competition, utilities will buy their turbomachinery for STIGs from U.S. heavy industry.

Let me complete this future development train of thought before getting back to the near term. Raising firing temperatures and reducing parasitic cooling losses promise big efficiency gains -- perhaps another 5 or 10 percentage points on efficiency. This might be done either by improvements within the engine or by adding ceramic topping devices, much as superchargers are added to boost engine power at the low temperature end. I don't think we've seen the end of major aircraft engine improvement and we haven't even begun to work on ceramic toppers. Efficiency of STIGs with tomorrow's aero-derived gas turbines and toppers could be 60, maybe even 70, percent.

You may recall that, before nuclear power came along and captured utilities' attention in the mid-1950s, generating costs were improved by improving steam conditions with superheat, reheat, higher pressures, and higher temperatures. Obviously, this improved fuel efficiency. What you may not recall is that improving steam conditions increased net power per pound of stuff: fluid, equipment, piping, and structure. Optimum plant size increased partially as a result. Plant size also increased to get simple scale-up economies. Generating costs went down for fuel and for plant cost.

Steam cycles cannot return to that pattern because efficiency levels off after top temperatures are past 700^{o}F where the liquid phase is no longer available for regenerative feedwater heating. Gas cycles, like STIGs, promise a return to the kind of compounding of improvements that we saw in steam cycles during their improvement heyday. But it seems likely that with STIGs, scaling up need not be carried to an excess to get the improvements.

If STIG is promising and simple, what's the problem getting it fully developed on advanced engines? What makes the development difficult?

A precision machine like an LM-5000 cannot be turned into a STIG just by connecting a steam pipe to the gas turbine combustor and opening the valve. It has to be done witout upsetting flow balances, temperatures, pressures, and a lot of other factors. In effect a new design condition must be found and mechanical changes made to accommodate the new conditions. Modifying an engine to make it a STIG is a major design change. A little redesign may be enough to get by with some steam injection. But getting peak output and efficiency from steam injecting an advanced gas turbine requires major developmental change to the engine -- and a lot of proof testing. That takes time and money.

In the case of the optimized LM-5000, General Electric concluded that to get the kind of performance we were looking for would require intercooling the engine and completely changing the power rating. To intercool the compressor will require replacing some stages of the compressor and addition of scrolls to get air out and back in for the intercooler. The changed rating requires a new power turbine. Unless these features can be made from adaptations of existing designs, GE projects that about $100 million is required to develop the ISTIG from the basic LM-5000 engine.

The current market is not strong enough to assure that such a large development cost will be recovered. To get it developed will require some of the following: a large development contribution or subsidy, finding existing hardware designs that can be substituted for parts which would have to be developed, thereby reducing development cost, or a big enough early market commitment to cover the development cost.

I do not foresee utilities putting up a very large share of the commitment that appears to be required. Utility evaluators are unlikely to make a case that comes out strongly in favor of 110 MWe ISTIGs over 200 MWe combined cycles. Unless a way can be found to reduce development cost, I don't see where the development money will come from.

We have had to do a lot of rethinking lately, not just about STIGs but about new generation in general. As I alluded to earlier, the power generation technology sweepstakes is taking place on the uneven playing field created by regulations that are adverse toward central station generation.

We have thousands of megawatts of power purchase contracts with outside developers for sales to our grid. Additional purchases will mean curtailing fairly low incremental cost generation and, consequently, we don't have much need for new central station generation.

Cogeneration is springing up all over our system. Table 4.3 gives some idea of how good an option cogeneration is. Combined fuel use for electricity and heat can beat an electric-only power plant efficiency.

Table 4.3 Comparison of electrical efficiencies of gas turbine options.

	Gas turbine alone (MWe)	Efficiencies (higher heating values) simple cycle	combined cycle	cogeneration*
GE Frame 5	25	25%	35%	44 to 57%
GE Frame 6	37	28%	38%	53 to 63%
GE Frame 7	77	29%	40%	53 to 63%
GE Frame 7F	135	31%	45%	55 to 65%
GE LM-5000	33	33%	38% (STIG)	49 to 60%
			47% (ISTIG)	49 to 60%
Allison 501	3.5	27%	36% (Cheng)	44 to 57%

* Fuel-chargeable-to-power efficiency.

Notes:

- o A large (750 MW) supercritical steam cycle unit with $90^{o}F$ exhaust has 36% HHV efficiency on natural gas.
- o Above gas turbine efficiencies are typical guarantees. Efficiencies can be substantially higher than shown at peak firing temperatures, low ambient temperature, etc.
- o Higher end of efficiencies for cogeneration corresponds to multi-pressure and low steam conditions heat use.

Notice that the fuel chargeable to electricity in some cases is equivalent to 60% HHV efficiency. An electric-only 110 MWe ISTIG at 47% efficiency cannot match the fuel saving of a 3.5 MWe Cheng cycle cogeneration plant with a good heat use.

Any electric customer with a good steady electric load and heat use has the cogeneration option. Utilities are very restricted in what they can do about participating in or owning cogeneration projects. This is too bad, because the cogenerating customer gets the best of all worlds and his cogeneration plant will not be optimized to serve anyone but himself.

For example, the utility provides backup for the cogenerator but the cogenerator avoids paying a lot of the utility's overheads because he does not draw on the system very often. The utility is left with less load to serve but with a system generally adequate to provide the backup, with the system costs being paid for by fewer customers. It is hard for a utility to make a good case for high backup rates. We've got the kind of situation the telephone company found itself in when choice customers could be plucked off its system leaving it with the high cost service.

Assuming utility avoided cost is low, the cogenerator sizes his plant to serve his electric needs alone, in most cases leaving much of the heat that could provide cogeneration benefits unused.

It would serve the public interest if utilities were permitted to work out business arrangements with heat using electric customers without regulatory prohibitions but with usual regulatory overview. This would enable benefits of cogeneration to be optimized and integrated to provide the greatest benefit to the greatest number of customers. Reasonable business arrangements should be permissible, including giving the customer with the heat use special rate treatment.

This is where much of the new generation activity is in our area. We don't have to build much new central station generation for a very long time. And we have adopted a corporate goal of offering price and service options that meet growing competition in particular markets, such as onsite cogeneration system bypass. But we may not be permitted to do what we can to maximize benefits of cogeneration to the greatest number of customers.

That is the situation on STIGs. Central stations are not where the action is now. But a STIG can be an excellent cogenerator, particularly where heat use is intermittent or variable. And in the small sizes, it looks like STIGs are doing okay.

Jerry Burkett, ASEA-STAL:* Burkett described the total number and installed capacity of ASEA-STAL's gas turbines worldwide, as shown in Table 4.4.

Burkett's presentation focussed on the GT-35C gas turbine (Fig. 4.4), and its operation with massive steam injection. The conventional GT-35C has a 12.5:1 compression ratio, 850°C turbine inlet temperature (TIT), an output of 17 MW, and a relatively high overall efficiency, 32%, for such a low TIT. The high efficiency leads to a relatively low turbine exhaust temperature.

ASEA STAL experience with steam injection includes a patent application submitted in 1951, combustor tests done in 1951 and NO_x reduction studies since 1975. With maximum steam injection (about 8:1 steam-to-fuel), the output of the GT-35C increases from 17 to 24 MW (26 if hardware changes are made), and the efficiency from 32 to 38% (~40% if hardware changes are made). NO_x emissions drop to under 10 ppm. For

* All discussions reported in this section from this point on are based primarily on hand-written notes taken during the workshop.

Table 4.4. ASEA-STAL gas turbines in use world wide.

Model	GT-200	GT-120	GT-35	PP	TOTAL
Exported	--	13	82	53	148
Sweden	1	8	4	16	29
TOTAL	1	21	86 (a)	69 (b)	177
MW	83	1160	1110	1199	3462

(a) 79 for power generation [6 with heat recovery, 68 onshore, and 5 offshore] and 7 for mechanical drive.

(b) Gas generators from Rolls Royce, General Electric, Pratt & Whitney

comparison, the combined cycle based on the GT-35C has an output of 21.6 MW and an efficiency of 40.5%.

Various modifications of the non-STIG GT-35C can be used to convert it into a STIG machine, leading to the improved performance, as summarized in Table 4.5 for operation at ISO conditions with an unfired boiler. The performance as a function of the mass of steam injected is shown in Fig. 4.5.

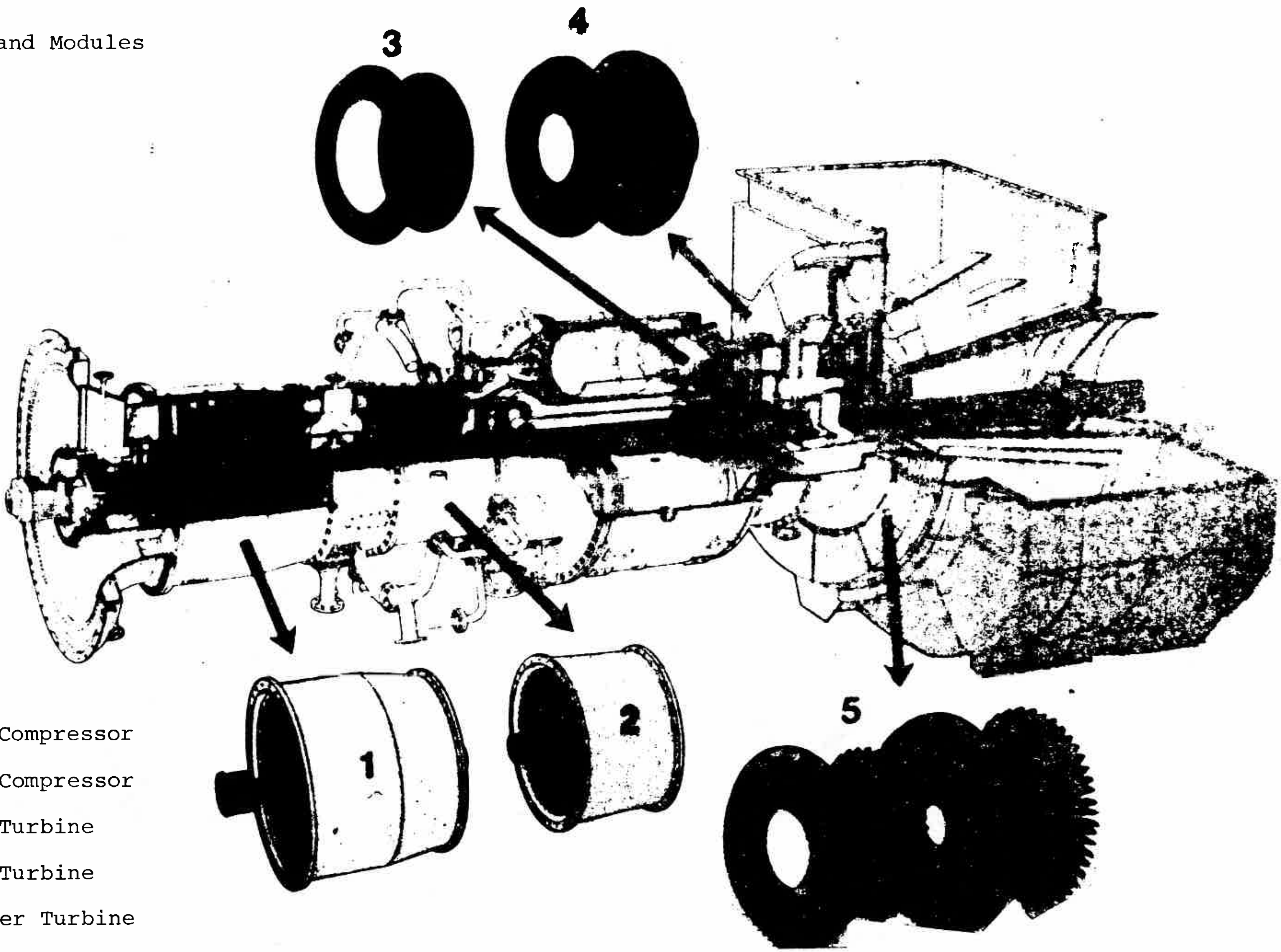
Concerns related to steam injection that are being addressed at ASEA-STAL include: the reduced stall margin from the increased compression ratio, water quality and expense, expense to redesign high temperature units with sophisticated blade cooling concepts, temperature profile in the turbine which may require combustor redesign, increase in CO and unburned hydrocarbons and instability, visible exhaust plume, and cost of the control system. A development program for the GT-35C STIG is expected to cost around $150,000.

Table 4.5. Modifications to improve performance of the GT-35C.

	Output (MW)	Efficiency (%)
GT-35C:	17.1	32.0
+ waste heat boiler (simple cycle)	16.7	31.7
GT-35C with Steam Injection:		
(a) adjust stator high pressure turbine	23.8	38.5
(b) (a) + adjust power turbine	24.0	39.0
(c) redesign flow areas	25.8	40.3

Richard Foster-Pegg, PE, Independent Consultant: Foster-Pegg presented his ideas for using turbo-charged steam-injected gas turbines, which would permit non-aircraft derivative machines (e.g., Brown-Boveri, General Electric Frame, and Solar turbines) to exploit the benefits of steam injection.

GT 35 and Modules



1 LP Compressor

2 HP Compressor

3 HP Turbine

4 LP Turbine

5 Power Turbine

Fig. 4.4

ASEA STAL

FOR GT-35C WITH STEAM INJECTION
AT CONSTANT TURBINE INLET TEMP. 850°C

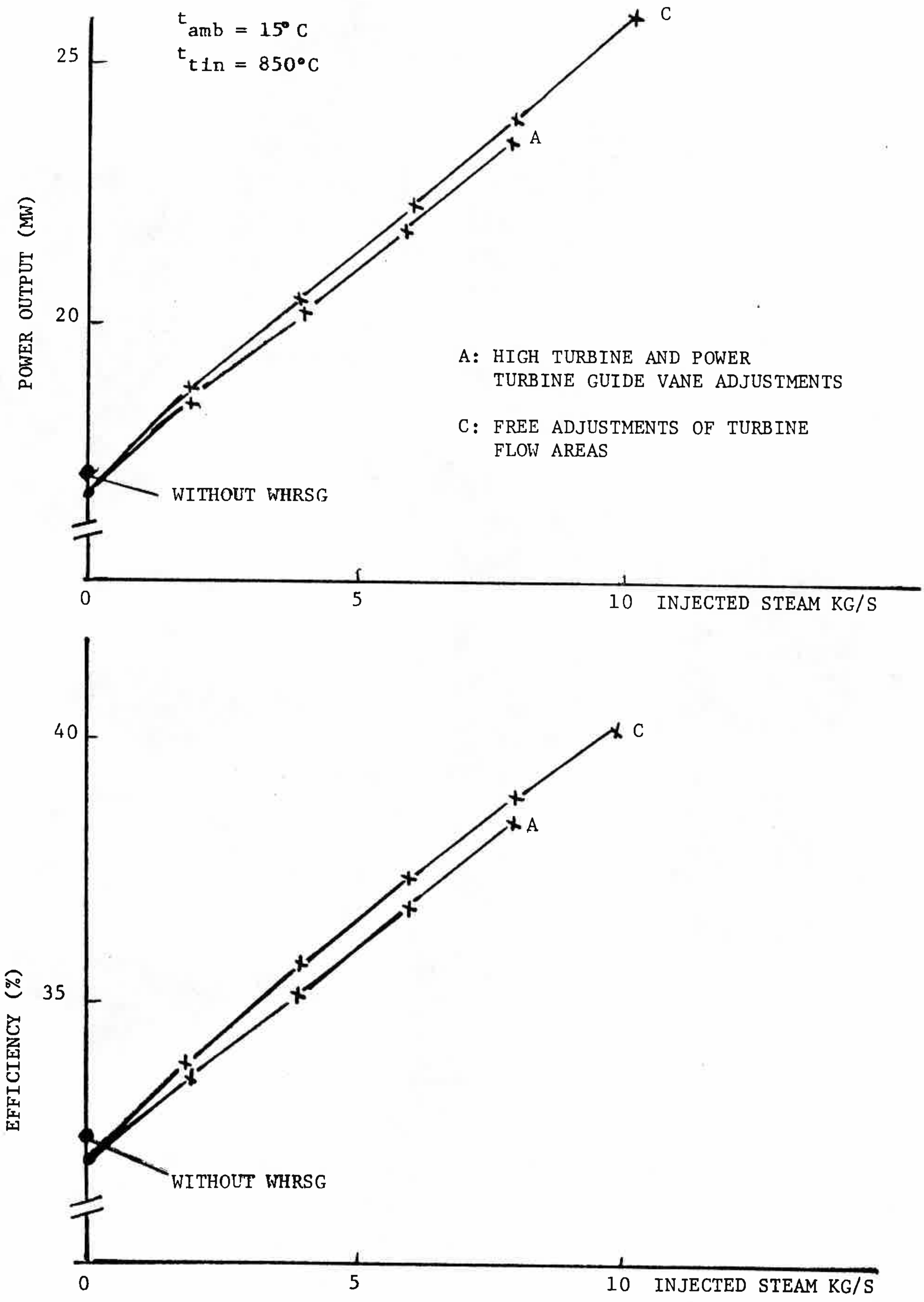


Fig. 4.5

The turbo-charged STIG would benefit from a 2-pressure heat recovery boiler. Lower pressure steam would be injected directly into the gas turbine combustor. Before being injected into the combustor, higher pressure steam would first expand through a small back-pressure steam turbine driving an auxilliary compressor which raises the pressure of the already-compressed air before it enters the combustor (Fig. 4.6). Thus, the booster accommodates the additional pressure rise resulting from the steam addition. The pressure ratio of the main compressor is not increased (it may be decreased), and the surge margin is not reduced. The efficiency of the turbo-charged STIG would be maintained at its full-load value down to about 80% power level.

An alternative to the turbo-charged STIG is the combined-cycle STIG, in which high pressure steam flows through a back-pressure turbine to produce electricity before exhausting into the combustor of the gas turbine. As indicated in the table below, the turbo-charged STIG would have about the same heat rate as the combined-cycle STIG, but would produce about 40% more power.

Foster-Pegg also described a turbo-charged, indirectly-fired STIG utilizing solid waste as a fuel (Fig. 4.7). Steam injection makes it possible to fire gas turbines indirectly with low quality fuels and low turbine inlet temperatures at an efficiency approaching that for direct-fired simple-cycle machines operating at a much higher TIT.

Table 4.6 summarizes the performance of several alternative turbo-charged STIGs.

Table 4.6. Performance comparisons of turbo-charged STIG systems.

Engine	Solar Centaur		W'house CW-251			W'house CW-191
Cycle	SC	STIG	SC	CC	STIG	STIG
Compression Ratio	10.2	9.29	13.7	13.7	12.17	7.6
Booster Ratio		1.19			1.32	1.23
Expander Inlet (F)	1750		2150			1500
Expansion Ratio	9.43	10.3	12.3	12.3	14.51	8.5
Steam Percent		14		14.5	20	16
Net Power (kW)	3,760	6,440	37,406	59,000	83,300	30,907
Heat Rate (BTU/kWh)	13,750	10,080	13,090	8,300	8,350	13,308
Fuel	natural gas		natural gas			solid waste

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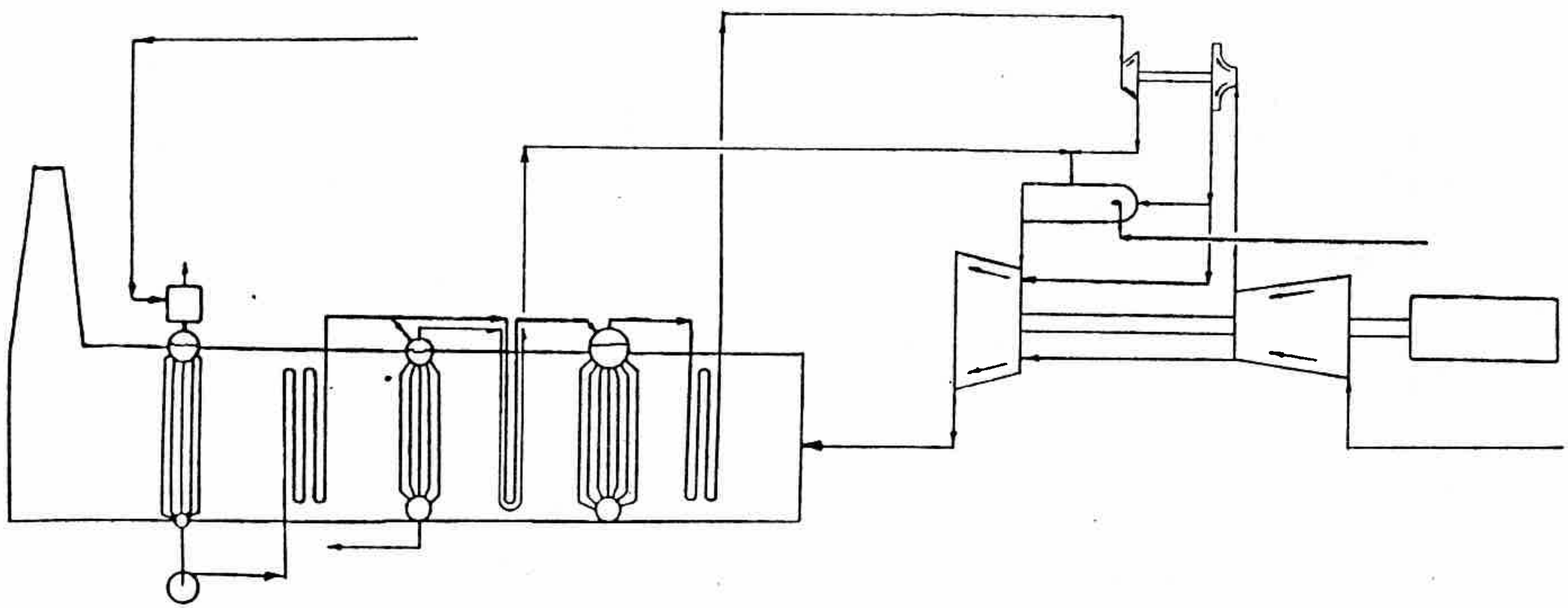

TURBOCHARGED S T I G CLEAN FUEL FIRED

Fig. 4.6

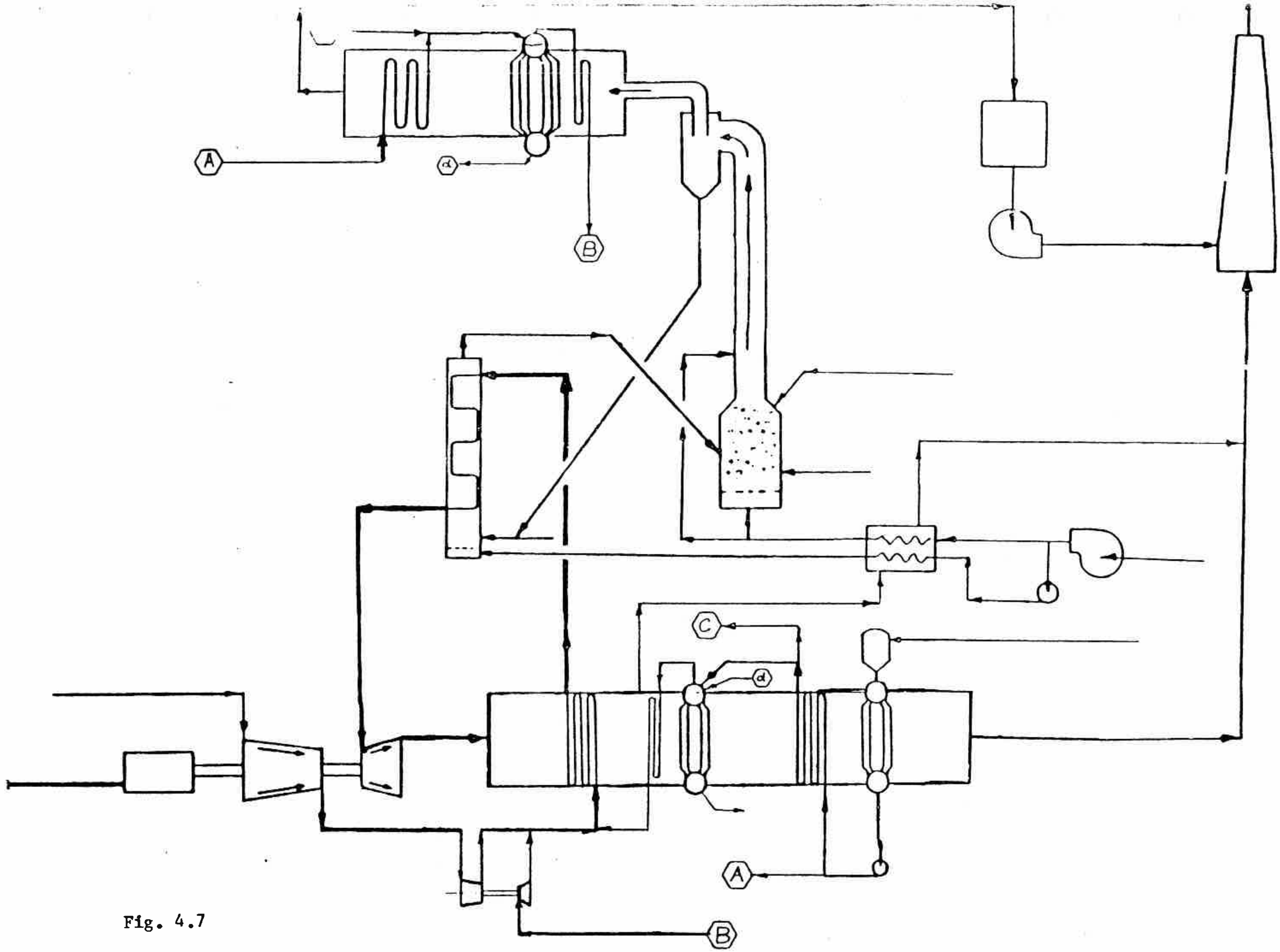

Fig. 4.7

TURBOCHARGED S T I G WASTE FUEL INDIRECT FIRED

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Foster-Pegg observed that GE may be considering intercooling its LM-5000 STIG in order to help match compressor and turbine flows of this 2-spool machine, and thereby avoid running up against the compressor surge limit. With the turbo-charged STIG, the compressor pressure ratio could be unaffected, even with injection of 15-20% steam.

He agreed with Ashworth that STIG should start small and build up to larger systems, since high costs are involved in putting new machines into production. The turbo-charged STIG would be attractive because it could be developed with relatively minor modifications to existing machines.

Discussion Highlights: Nicholas Esposito (Jersey Central Power and Light) indicated that New Jersey utilities are interested in combined cycles because they would reduce water consumption. If STIGs would consume even less water than combined cycles, as suggested by Ashworth, then their water consuming characteriestics would make them of interest for applications in New Jersey.

Flye indicated that Stewart and Stevenson is working on two gas-turbine based power generating systems, each a combined cycle plant: a 235 MW one is to be installed in Rhode Island, utilizing 10 GE LM-2500s, and a 200 MW plant consisting of 4 LM-5000 STIG-120s, to be installed in New Jersey. Exemptions from the Fuel Use Act (FUA) have been obtained for both plants.

Burkett explained that economic exemptions were relatively easy to obtain for plants in the 200 MW size range, since all that is necessary is to show that the cost of electricity from the proposed plant will be cheaper than from a comparably sized coal-fired plant.

Flye indicated that construction times for gas turbine systems can be very short: One project built in Hawaii by Stewart and Stevenson required 10 months from the contract signing to the production of electricity (28 days between arrival of equipment on Hawaii and the first production of electricity). In another project with Shell Oil, an LM-2500 packaged system, including water injection for NO_x control, was completed in 6.5 months. Stewart and Stevenson has rotating arrangements with GE, Brush Electric, and other vendors to shorten the time between ordering and shipment. Stewart and Stevenson also builds gas turbine plants for simple or combined cycles.

4.2. STIG versus Combined Cycles

The panel consisted of Wieble Alley (Arkansas Power and Light), Jerry Burkett (ASEA-STAL), Fred Robson (United Technologies), and John Tuzson (Gas Research Institute). Presentations were made by Alley, Robson, and Tuzson.

Wieble Alley, Arkansas Power and Light: Alley gave his perspectives as a utility engineer on the future of combustion turbines in central station power generation. He stated that his comments do not necessarily reflect the policies of AP&L or any other utility.

For utility capacity expansion planning, new nuclear plants are not a viable option for the foreseeable future. The principal conventional alternative is coal in 2400 psi (non-supercritical) steam plants of 600-800 MW. Any unconventional alternatives to nuclear and coal steam plants should have heat rates and costs comparable to or better than those for such coal plants, and preferably also short lead times (from permitting to pushing the button), small capacity increments to allow utilities to expand in a manner that tracks load growth, minimal water consumption, and the ability to use oil and gas in the near term as bridges to coal in the longer term, with a minimum adverse impact on the environment. If industry is to develop the new technologies the utilities need, the utilities need to give a clear signal of what they are looking for.

The combustion turbine in various configurations is well-suited for meeting these utility planning needs. While the prospects for improving steam turbine performance are not promising, there is significant room for advances in combustion turbines. Topping cycles will be important. For example, a solid-oxide fuel cell could top a combustion turbine, leading to heat rates of about 5000 BTU/kWh. Conventional and unconventional regenerative-type systems (e.g., the evaporative-regenerative cycle) will also be important.

Potential new sources of electricity supply for AP&L will include:

(1) Utility-owned cogeneration systems. In Arkansas, the cogeneration potential is about 1400 MW, about 1000 of which would be located in high load-factor industries that are bound to a localized resource, e.g., forest products mills. By adding cogeneration capacity, the generating base can be increased in small increments.

If a move is made to coal, larger sites -- centralized cogeneration facilities -- will be required, since coal is sensitive to economies of scale: one million tons/year is about the minimum that a plant can consume economically, corresponding to a 365 MW plant.

Alternatively, since it may be economical to pipe coal gas 150-200 miles, coal might instead be consumed in centralized gasification facilities, which could feed small decentralized generating or cogenerating plants based on the use of various possible combustion turbine technologies and served by dedicated medium BTU gas pipelines.

Technologies such as the LM-5000 modified for STIG operation might be used simultaneously for cogeneration purposes and as spinning reserve by the utility. The latter possibility arises because with steam injection and supplementary firing electrical output can be increased up to 50% over the output for the case where all the steam produced in the unfired heat recovery steam generator is used for process use.

Utility ownership is an issue: the PURPA limit is 50%, unless the plant becomes part of the rate base (selling steam and electricity), in which case there is no limit.

(2) Existing utility plants using gas or oil. AP&L has 5 plants, 13 units with 2250 MW, 8-13 years old, which are rarely used at present.

(3) Greenfield plants, in which the plant location and design are integrated with sales and marketing activities, e.g., at a new industrial park or housing development.

Fred Robson, United Technologies: Approximately 25,000 MW of Pratt & Whitney gas turbines are installed in the field, many of which are of the FT4A Series, which can be readily operated with steam injection, by injecting into the combustor and/or free turbine.

A gas turbine-steam turbine combined cycle and a steam-injected gas turbine cycle are shown in Figs. 4.8 and 4.9. The increase in power output of a Series FT4A with steam injection relative to a simple-cycle is significantly higher than for a FT4A-based combined cycle, while the efficiency gains are more modest (Fig. 4.10). The increase in power output of a STIG with increasing turbine inlet temperature (TIT) is smaller than that of a combined cycle, but the respective heat rates decrease at the same rate with increasing TIT (Fig. 4.11).

In a STIG, injection of superheated steam into the combustor leads to lower heat rates compared to injection of saturated steam, but power output is essentially the same for both saturated and superheated steam (Fig. 4.12). However, if steam is injected into the free turbine, both power output and heat rate are improved when superheated steam is used (Fig. 4.13). Over a compressor pressure ratio range of 8 to 16, the power output of a STIG remains relatively unchanged at a fixed TIT (Fig. 4.14).

With water injection into the combustor, for NO_x control, power output is enhanced, but the heat rate increases (Fig. 4.15). Thus, it is likely that steam will increasingly replace water for NO_x control.

The steam generating capability of a Series FT4A cogeneration system covers a wide range of steam temperature and pressure (Fig. 4.16). On a retrofit of existing engines, an injection-steam to air ratio of about 10% can be tolerated without major modifications to the engine, and hence at relatively little cost.

John Tuzson, Gas Research Institute: Gas turbine systems are inherently more attractive than steam turbine systems because they are simpler and hence less costly, e.g., no cooling tower is required. In small sizes, combined cycles utilize small steam turbines, which have relatively low efficiencies due to small flow passages, etc. The flexibility of STIG in small sizes is potentially important to utilities in peak shaving.

Research on gas turbines is driven by military needs. The military is interested in aircraft power, not stationary power. Thus, industry must adapt military hardware, since industry does not have the requisite R&D money readily available. STIG takes advantage of the the characteristics

GAS TURBINE CYCLES

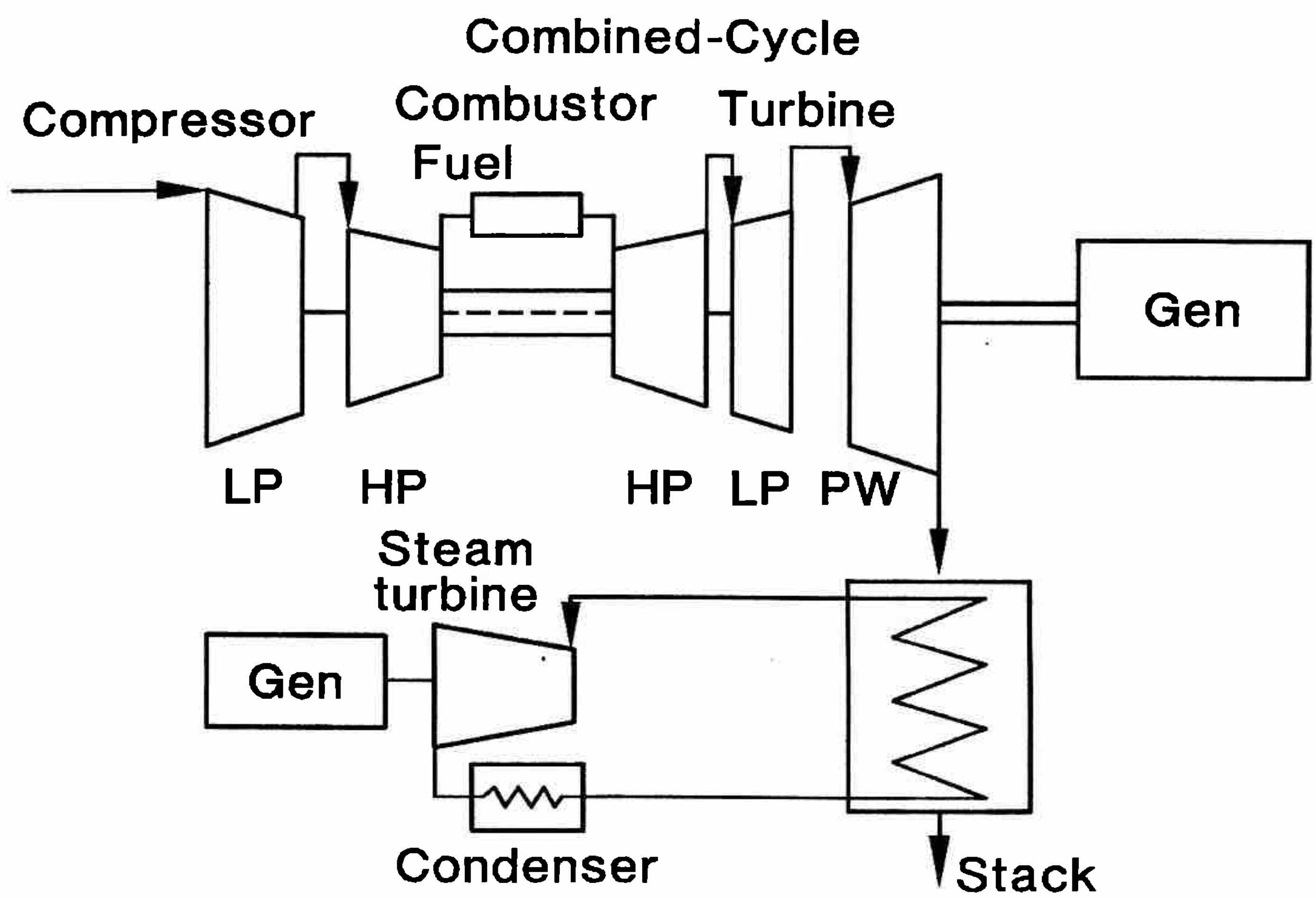


Fig. 4.8

RA1603TX.001

GAS TURBINE CYCLES

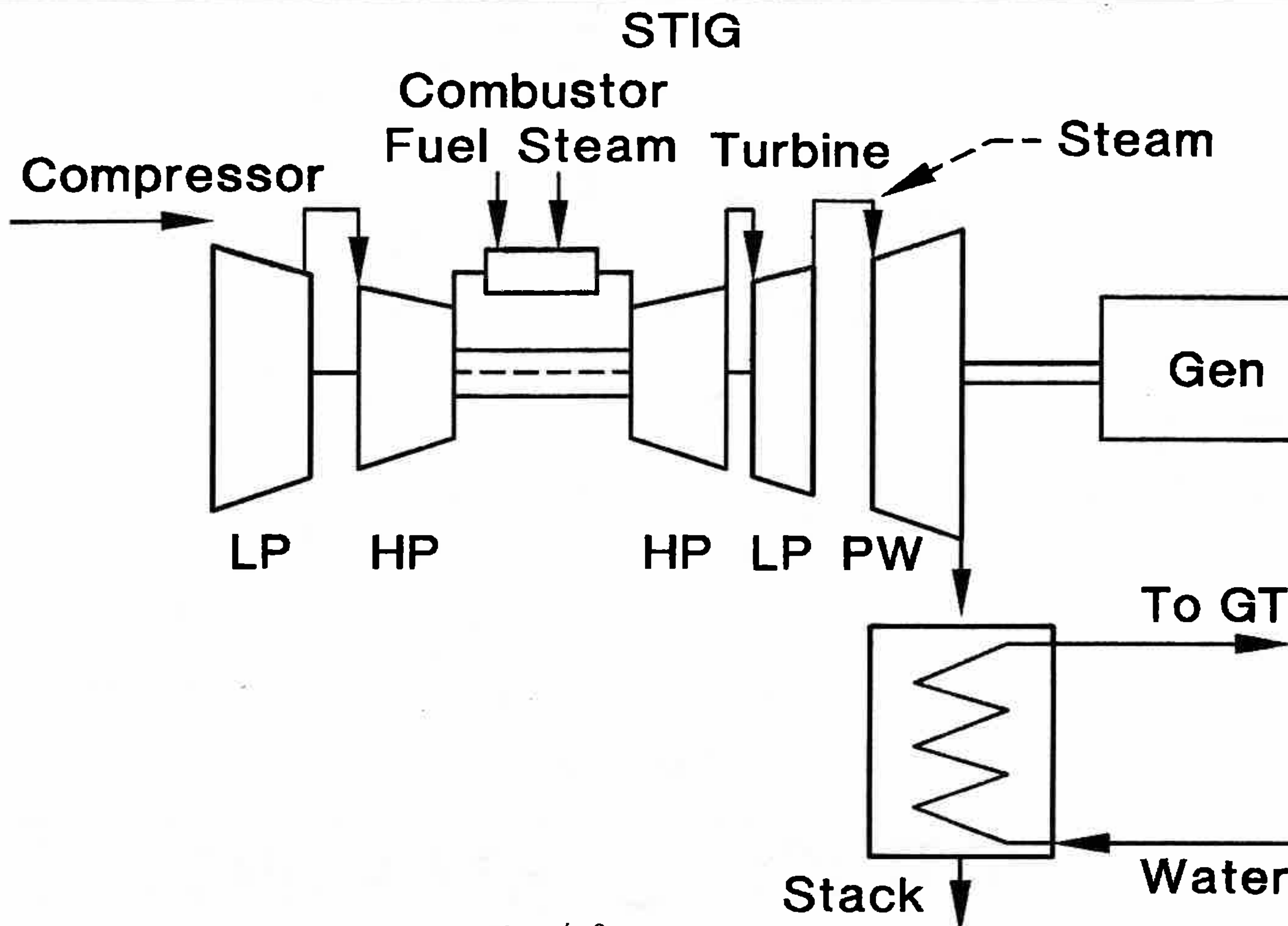


Fig. 4.9

RA1603TX.002

BASIC PERFORMANCE COMPARISON

FT4A SERIES

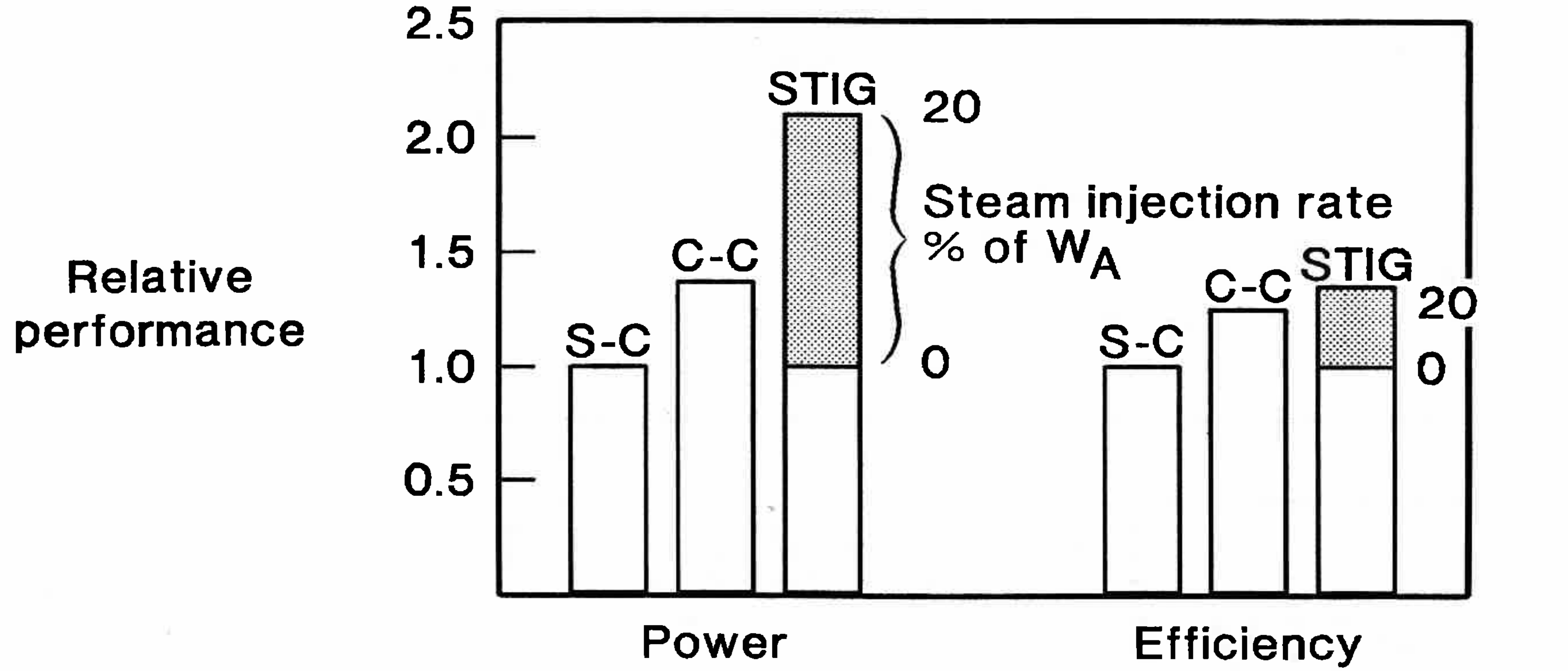


Fig. 4.10

PERFORMANCE TRENDS WITH TURBINE TEMPERATURE

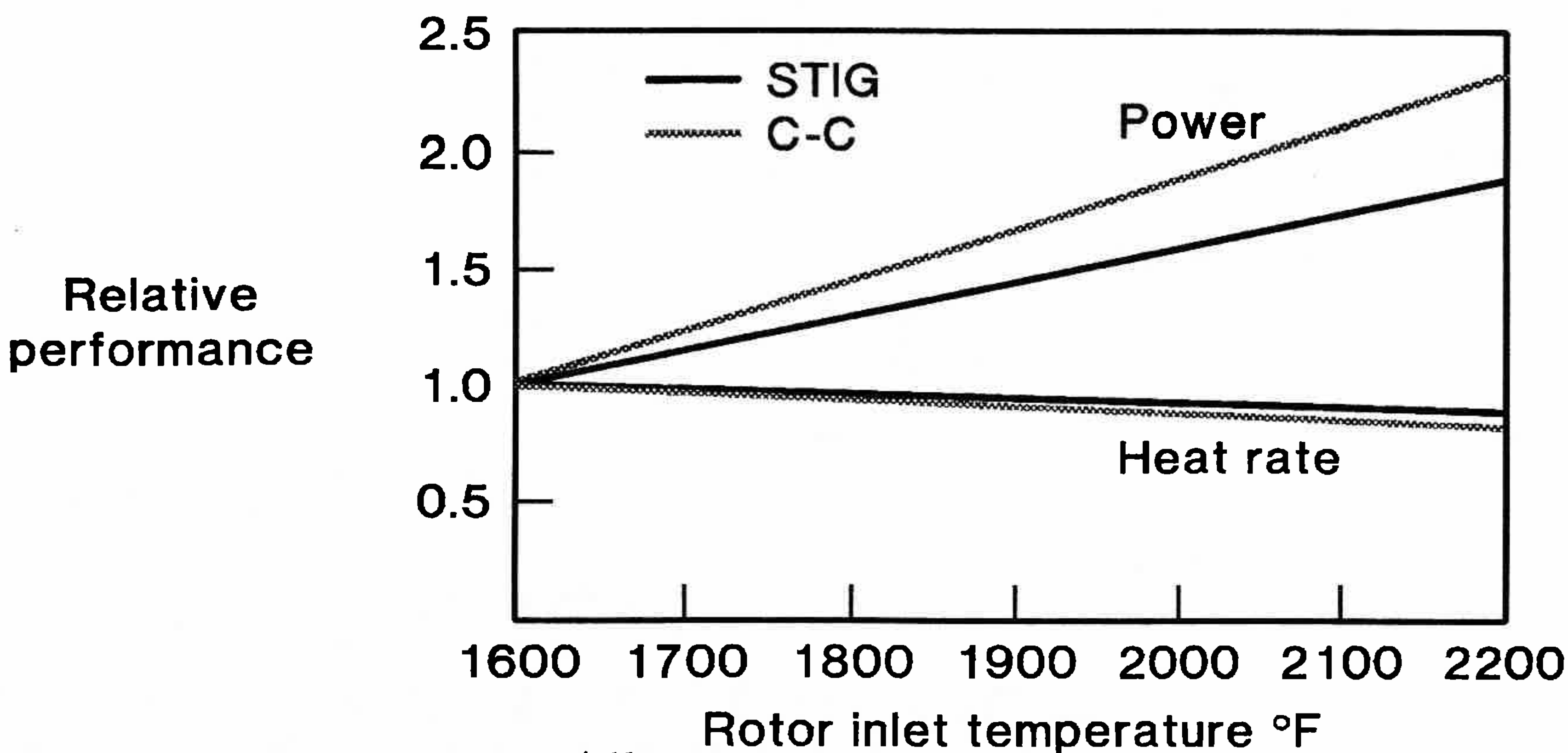


Fig. 4.11

RA1603TX.004

STEAM INJECTION

COMBUSTOR

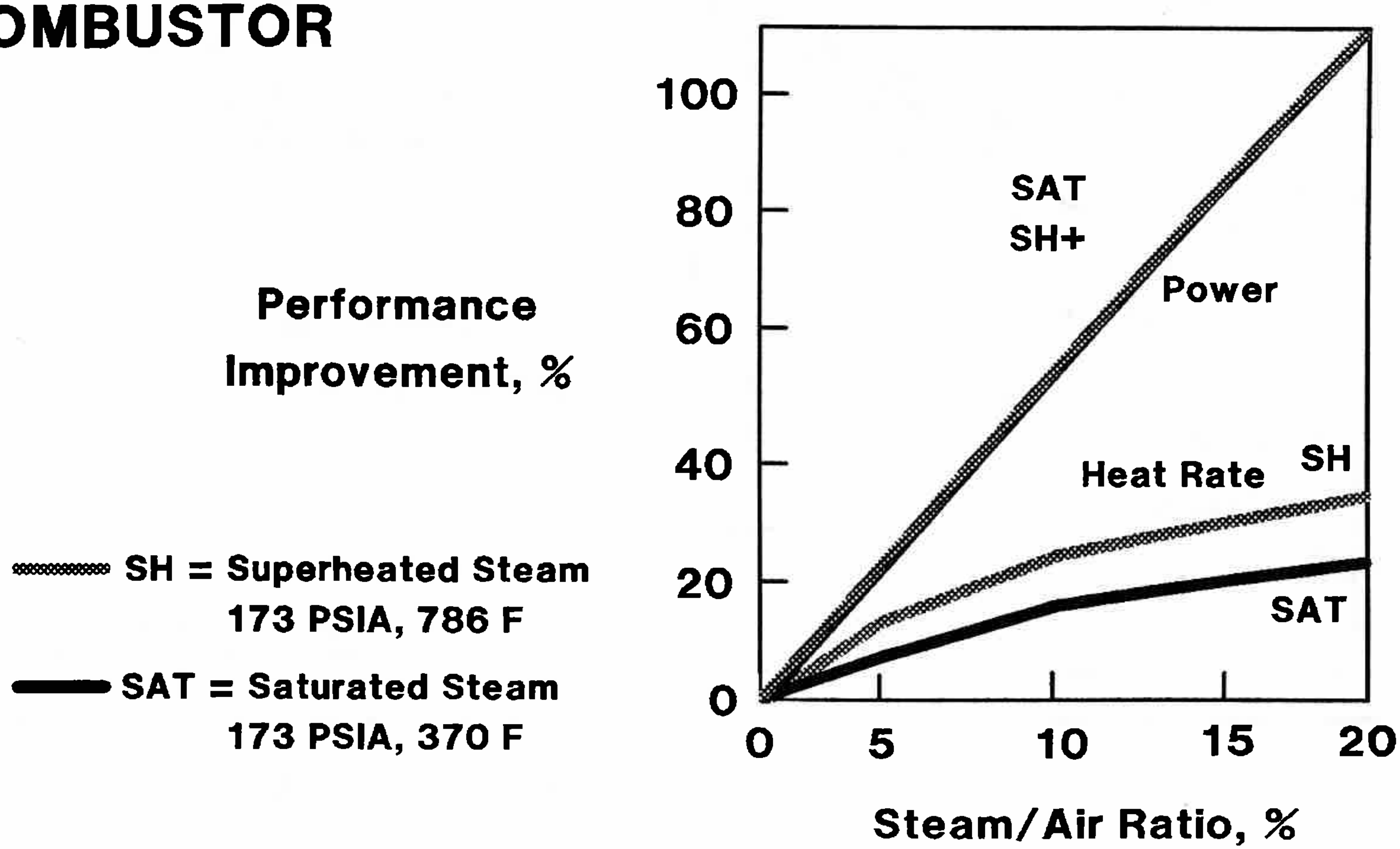


Fig. 4.12

PC4A2TX

STEAM INJECTION

FREE TURBINE

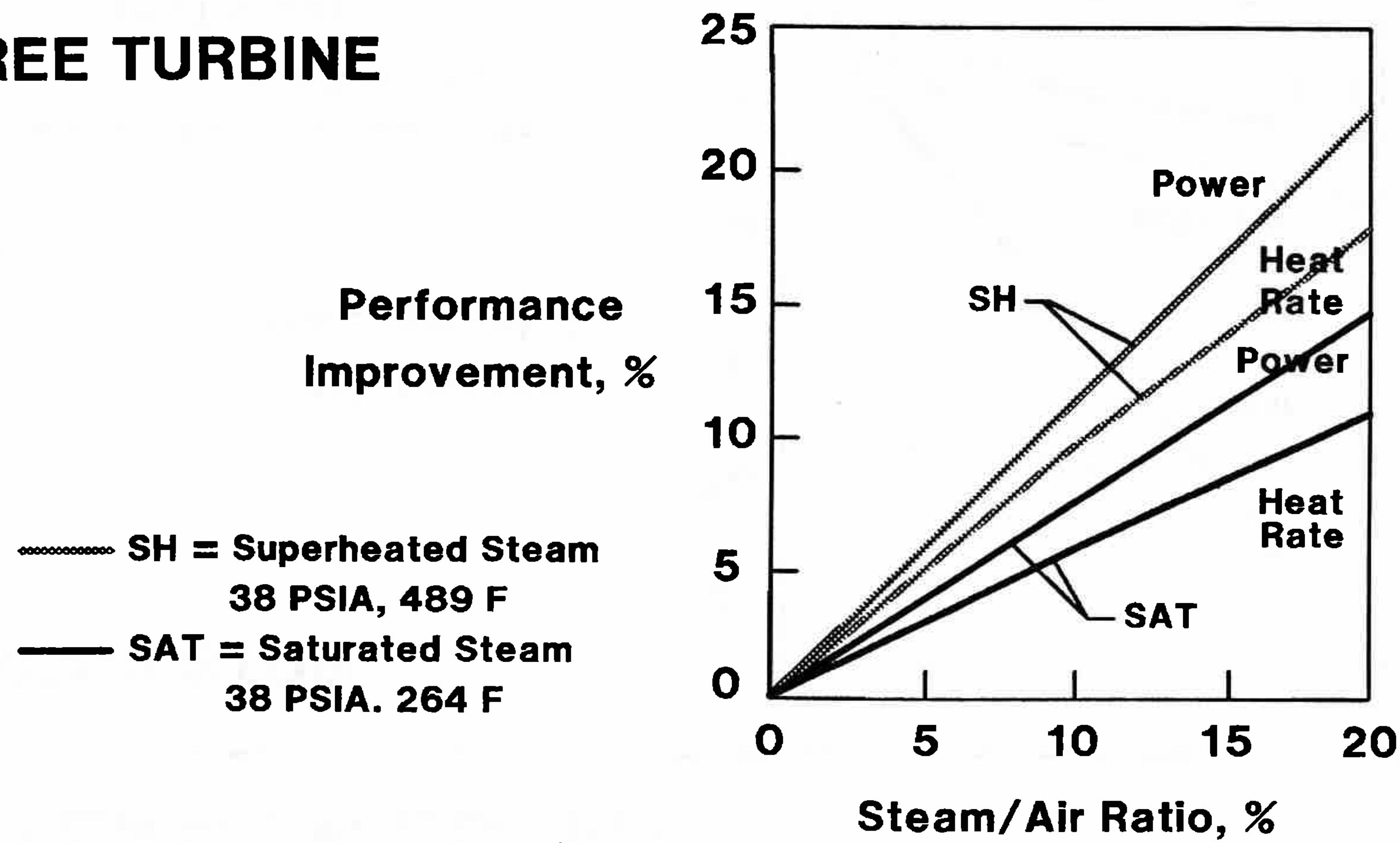


Fig. 4.13

PC4A3TX

PRESSURE RATIO VS OUTPUT POWER

STEAM INJECTION

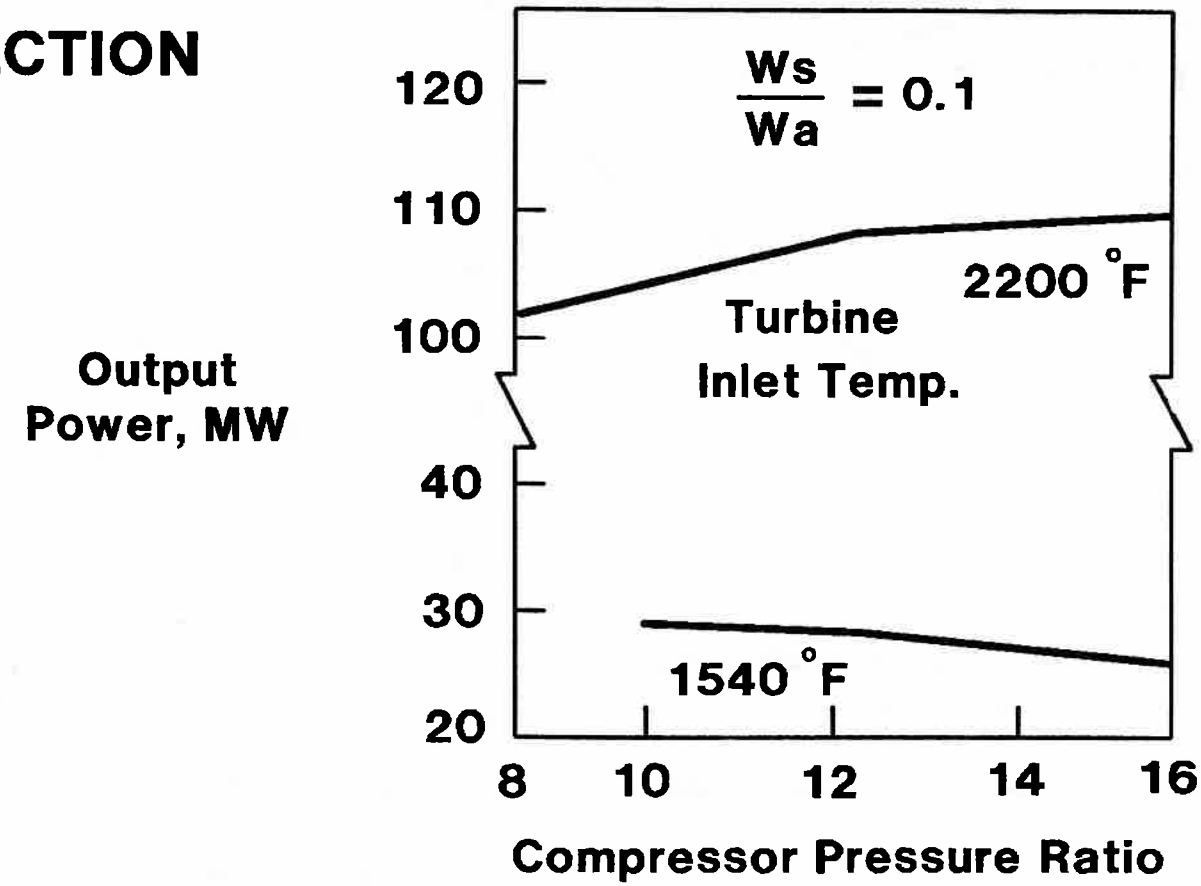


Fig. 4.14

PC4A4TX

WATER INJECTION

COMBUSTER

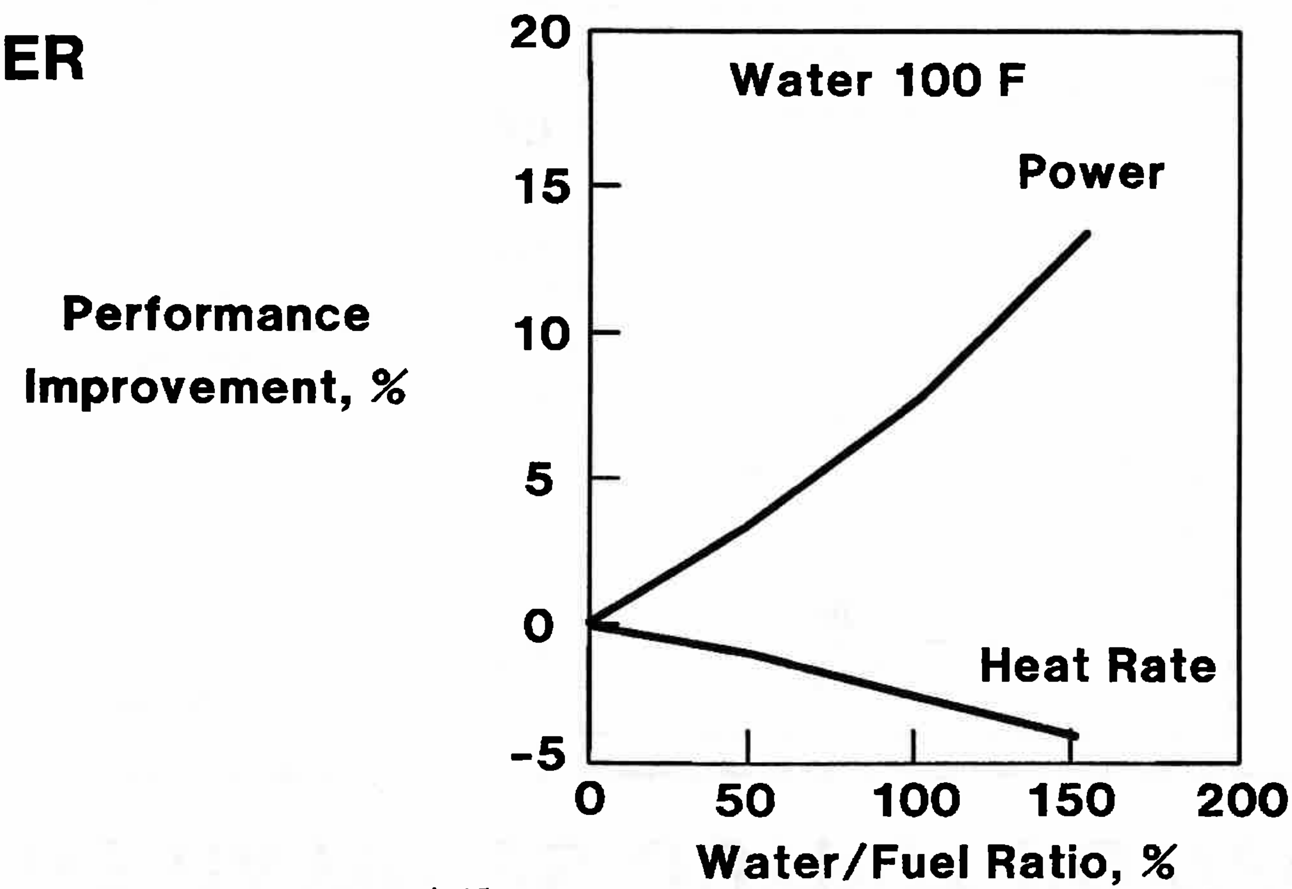


Fig. 4.15

PC4A5TX

HEAT RECOVERY STEAM CAPABILITY

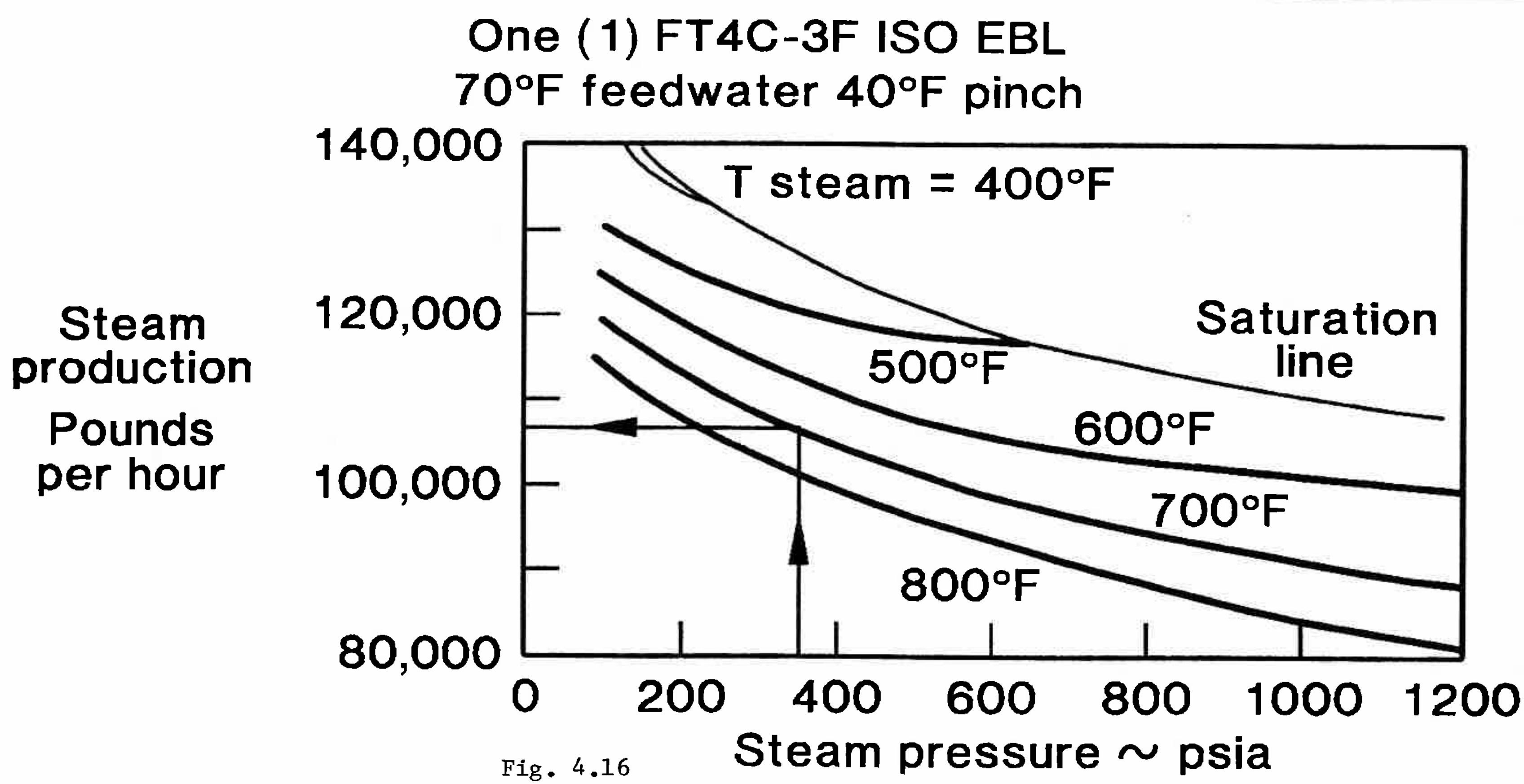


Fig. 4.16

RA1603TX.003

of aircraft engines, so past military-related R&D has done double-duty in this regard. However, other developmental work on gas turbines for stationary power has not been done, e.g., because an intercooler cannot fly in a jet fighter.

One area where R&D is required with STIGs is water quality. Data need to be developed for the level of water treatment necessary.

Discussion Highlights: Burkett stated that in the 30-50 MW range, the use of recently developed tall blades, with small rotors, in steam turbines can lead to 3-5% improvements in turbine efficiency.

Tuzson indicated the importance of building a data base documenting actual STIG performance in the field. GRI is in contract negotiations to monitor the performance of some operating STIG systems.

Charles Graham (formerly Dow Chemical) stated that utilities are the biggest market for gas turbines. But Michael Curley (North American Electric Reliability Council) noted that utilities are looking to coal and are slow to try new technologies. Management needs convincing to move away from life-extension projects.

Robson said that to avoid the surge margin on a multiple shaft machine, either (1) the turbine flow area can be opened up or (2) careful control of the system can be exercised. Better control is possible. For retrofits of existing engines, a maximum of 10-12% steam injection is possible.

4.3. Water Quality Requirements

The panel consisted of Clint Ashworth, George Cain (Mechanical Technology, Inc.), William Flye (Stewart and Stevenson), and Ralph Kidder (Allison Gas Turbines). A presentation was made by Cain.

George Cain, Mechanical Technology, Inc.: What water treatment level is required for steam injection?

Liquid water enters the boiler, is turned into steam and in some cases passes through a superheater before being injected into the turbine.

Water won't form at temperatures found inside the gas turbine, so liquid impaction/erosion is not a concern. The main concern is carryover from the boiler drum and the chemicals that tend to concentrate there. The most volatile of the chemicals is silica, but this is generally not a problem at pressures below 400 psig. Of greatest concern to the gas turbine are sodium and chlorine ions. The high temperature regions in the boiler tend to concentrate the chemicals beyond their solubility in water droplets or in steam. Off-design operation is of most concern, since unless the fluctuations in the boiler drum water level are carefully controlled, carryover is likely.

Injected steam enters the combustor at 300-400°F and is immediately heated. Water droplets, upon mixing with the hot air, will be flashed to steam and the dissolved chemical content deposited on the hot walls of either the combustor can or the cooling passages in the turbine blades. Buildup of contaminants leads to scale buildup, and high chlorine or caustic solutions that can lead to stress-corrosion cracking.

To alleviate chemical contamination of the injected steam, some of the following steps might be taken: (a) eliminate carry-over (although this is not realistic, particularly at off-design); (b) deal with carry-over through measures such as appropriately sizing the steam drum diameter/steam release area, properly designing and maintaining the steam drum water separation devices, avoiding operation at or above rated steam generation loads, avoiding steam load surges, and operating at a specified drum water level; (c) design the system for "off-design" operation.

Little data are available on what chemical treatments are best and on what effects chemicals have on STIG systems. Therefore, MTI is undertaking two research programs:

(1) The US Department of Energy is supporting a 5000-hour test to look at three levels of water treatment and three heat exchanger materials. Water treatments include: (a) deionized water with hydrazine and ammonia added for O_2 and pH control), (b) water with a coordinated phosphate treatment, (c) water with sodium phosphate and sodium hydroxide additions. Type of heat exchanger materials: (a) 310 stainless steel, (b) incalloy 800H, and (c) 347 stainless steel. Sample heat exchanger tubes will be placed in a 1400°F environment to heat air to 1350°F. Questions that will be addressed include: (1) Where will chemical deposition occur? (2) What effect does chemical buildup have on the materials? All 9 combinations will be run for 1000 hours. Tubes will then be cut open and analyzed to identify the best combination, which will then be run an additional 4000 hours.

(2) The Gas Research Institute is funding work to install and operate a STIG cogeneration system. Data on the long-term effects of water chemistry will be collected, analyzed, and published.

MTI is interested in STIG as a topping cycle, and also for use in externally-fired gas turbines, which are penalized by the use of the heat exchanger. Using steam injection can raise such systems back to a competitive level.

<u>Discussion Highlights</u>: Flye stated that all rotating machinery, especially advanced units, require clean air, clean oil, clean fuel, and clean water. Purification costs for an Allison system are 2-3 mills/gallon.

Kidder described the water quality required for NO_x control on Allison engines, and indicated that, given a lack of data, these same specifications are used for Allison STIG systems:

Total matter	2.0	ppm maximum
Dissolved matter	0.5	ppm maximum
Sodium	0.15	ppm maximum
Silicon dioxide	0.1	ppm maximum
Conductivity	1	micro-ohm/cm maximum at 25°C

Kidder also stated that while sodium and sulfur additives are sometimes used to treat boiler water, these additives are not appropriate for water treatment for STIG systems. Sulfur reacts with turbine metals, and sodium acts as a catalyst in this regard, so that efforts must be made to prevent turbine damage from sodium and sulfur. Naturally occurring sodium (e.g., from ocean spray) is often difficult to avoid, so that the recommended approach to preventing turbine-metal sulfidation is to control the sulfur. Avoiding drum upset and boiler carryover in general is important. If compressor outlet pressure drops significantly, boiler carryover will be blown through the turbine.

Ashworth indicated that if drum upsets can be avoided, there should be differences in water quality requirements for steam injection and for water injection for NO_x control. He stated that GE is not concerned with normal dust that enters the system, e.g., as kicked up during aircraft take-off and landing.

Tuzson indicated that water treatment criteria now used for NO_x control should not be automatically assumed to be necessary for massive steam injection, because standards for NO_x control may be overly conservative, since only small amounts of water are needed and hence costs are not significant. Flye suggested that there should be no difference in <u>actual</u> water treatment requirements for NO_x or STIG uses.

Ashworth noted that it appears that GE can guarantee 25 ppm NO_x and 25 ppm CO without catalytic NO_x control (e.g., without using ammonia), based on tests at a Simpson Paper Company plant in California. Flye, responding to a question, indicated that fuel type (gas, distillate, etc.) does not influence water purity requirements. Foster-Pegg indicated that corrosion and deposition are problems, since dust is molten at typical turbine inlet temperatures. Combining deposition with STIG, the surge margin on an engine might be quickly reached.

Ashworth stated that Simpson Paper uses demineralized mountain stream water in their LM-5000 STIG. Wood described the 4 measures used by IPT to prevent water problems: (1) start with "clean" water -- depending on site, it may be demineralized, (2) control the system to avoid boiler upset, (3) fully coat turbine materials, including cooling passages, to avoid sulfidation, and (4) use 10 micron screens in the steam drum.

Kidder stated that it is necessary to consider total contaminants entering the turbine, e.g., if operating in a salty fog. James Corman (General Electric) reiterated this point: one has to ask what goes into the 1st stage nozzle, including water, air, combustion products.... The acceptable quality depends on firing temperature, pressure, etc. Corrosivity and deposition tendency need to be looked at for different operating pressures and temperatures. A database needs to be developed.

Such considerations are becoming more important, as newer turbine blade materials tend to be less corrosion resistant. Irv Glassman (Princeton University) asked why ceramic blade coatings are not considered? Corman responded that thermal barrier coatings are used on some parts of hot path components (deposited by proprietary plasma spray coating), but it is difficult to insure that no deterioration of coating will occur over a 30 year plant life. Kidder agreed that a chink in the armor, leading to greater corrosion/erosion, is a problem with coatings. Flye added that the question has to be asked about what will happen when a piece of blade coating flakes off and passes through the rest of the system.

4.4. Operating and Maintenance Costs

The panel consisted of Wieble Alley (Arkansas Power and Light), Charles Graham (formerly Dow Chemical), and David Yosh (Jersey Central Power and Light). Presentations were made by Graham and Yosh.

Charles Graham, Dow Chemical (retired): If industrial companies who generate their own power were included in the list of power generators, along with utilities, Dow would rank in the top ten.

In 1951, Graham went to California to develop a power facility for Dow's Western Division Plant at Pittsburg, near San Francisco, at a time when public utilities were beginning to give preferential treatment to their commercial and domestic customers. Industrial companies began to turn back to self-generation, which had been a major source of power a generation earlier, when the utilities were not strong enough to serve them.

Graham and others developed a total energy system for Dow based on three Pratt and Whitney aero-derivative gas turbines. The plant is now 20 years old, 70 MW in capacity, and provides excess power for sale to the utility.

Table 4.7. Important characteristics of aero-derivative gas turbines.

1. Design is evolutionary	13. Maintenance alternatives
2. Light weight/multi-rotor	14. Fixes and upgrades
3. High compression ratio	15. Maintenance costs
4. High firing temperature	16. Maintenance effort
5. High-speed rotors	17. Off-site vs. on-site repair
6. Alloy materials and coatings	18. Maintenance cost control
7. Overload capacity	19. Spare parts
8. Packaged designs	20. Major parts source
9. Performance monitoring	21. Operating costs
10. Modular design	22. Maintenance costs
11. Capacity correction	23. reliability
12. Downtime control	

Graham listed 23 important characteristics of aero-derivative gas turbines (Table 4.7) and discussed 7 in detail:

(1) Inlet air cleaning: Aero-derivative machines are characteristically high compression ratio units. There are large benefits to keeping the compressor stages clean and efficient.

Formerly, the cleaning of compressors involved injecting abrasive materials into the inlet air stream to remove materials (often at least partly organic in nature) deposited on the blades that interfere with the action of the foils as they move through the air. Many abrasives were used, including granulated walnut shells.

Present day techniques involve the use of sophistocated water and detergent spraying. Available detergents are patent-medicine type formulations that can be mixed with condensate and administered through specially designed nozzles located around the periphery of the engine inlet. Cleaning under load is proving to be a practical routine operation, making it possible to keep deposits from building up between scheduled maintenance shutdowns.

(2) Inlet air cooling: There are also large benefits to off-setting heat of compression by reducing the inlet air temperature. Evaporative coolers are often designed into units where relative humidity is sufficiently low to provide the cooling effect desired during hot weather, providing a fairly flat inlet air temperature the year around. Refrigerated cooling is available in locations where humidity is high or icing conditions are anticipated.

(3) Lube-oil conditioning: Aero-derivative engines are usually lubricated with synthetic oils. These are esteric compounds with proprietary compounding, such as Mobil jet oil #254. It is important to run these lubricants at proper temperatures (230-250^{o}F) and to provide filtration, water separation, and metal detection in the circuit at all times. The "chip" detector is one of the best early warning devices available for machines using anti-friction bearings.

(4) Borescope inspection: Inspection ports are provided at key points in the engine and turbine casings for insertion of the borescope. Viewing from these points will reveal critical areas of both stationary and rotating elements of the machine. By slowly rotating the rotor, a good look at all blading is possible. The borescope can be fitted with a camera for recording these conditions. Combining this information with operating data can provide a sound basis for a preventive maintenance program. When the machine is opened up later, correlation can be made to the end that confidence in life expectancy of critical parts is soundly based. Evidence of foreign object damage (FOD), engine-part failure, deposition, erosion, heat distortion, and metal fatigue are important observations. Expert borescope readers are being developed as the population of machines grows. Look to vendors' service people as well as independent consultants.

(5) Engine monitoring: Adequate instrumentation should be available

to monitor the operation of any given machine. The basic data are the manufacturer's performance data for the class of machine in use. A signature curve must be generated for the specific unit. Readings are taken periodically, corrected to signature base conditions and a comparison made to determine deterioration from clean, or new, condition. Important parameters include rotor speeds, fuel rate, gas temperatures, electric load, thermal load, and vibration. The owner/operator should understand the monitoring reports and not be dependent upon the vendor completely for the interpretation of these data. Users should not be left in the dark on the condition of their equipment that effect reliability, availability, and O&M costs. Sharing information should be expected from the vendor.

(6) Engine repair facilities: Aero-derivative machines require maintenance support from off-site engine repair shops primarily used for flight engine repair. Maintaining one's own complete shop facility would be uneconomic. Since there are shops available to provide service at competitive costs, the power plant owner is spared the heavy investment for facilities and tooling for the specialized work involved. These contract shops also provide an experience base that is invaluable in providing solutions to unexpected problems. The result is "better work at lower cost." The vendor is a source of shop repair that should be considered in selecting a site for major work. He has an interest in supporting the product. With competition for the work, he will try to be competitive. Vendors tend to replace components rather than repair them, usually at greater cost. The aero-derivative lends itself to evolutionary changes (fixes and upgrades) that later become the basis for more reliable, higher capacity machines to serve the industry. The owner/operator provides the test-bed in this process, which is invaluable to the manufacturer.

(7) Maintenance costs: For Dow the maintenance costs for aero-derivative turbines have averaged some 2-3 mills/kWh. One DOW plant consistently runs less than 2 mills/kWh, including minor improvements done at the time of overhaul. Maintenance costs should be averaged over a five year period, since the tasks required have varying frequencies. Time between major shop visits also depends upon the owner's loading plans and could vary between 16,000 and 25,000 hours.

FIVE-YEAR CYCLE:		
	20 quarterly inspections	
	5 borescope inspections	
	3 annual inspections	
	1 hot-section inspection	
	1 major shop inspection	
	COST:	1.4 mills/kWh
PARTS FOR ABOVE:		0.2
ENGINE TURNAROUND:		
	Engine removal and return	
	Spare engine rental	
OVERHAUL COSTS:		1.4
TOTAL MAINTENANCE COST:		3.0 mills/kWh

Other power plant units such as power turbine, generator, heat recovery steam generator, etc., carry normal maintenance charges.

David Yosh, Jersey Central Power and Light: JCP&L power plants were built at various times in the period 1930-1977: 600-700 MW of capacity was installed in the 1950s (typically 2000 psi, 1000^{o}F steam); 150-200 MW is older equipment; there is 350 MW of combined cycle capacity, and 600 MW of simple-cycle gas turbines.

Maintenance costs depend on the accounting method used. The JCP&L experience has been that simple-cycle maintenance costs are 10-15 mills/kWh (not including loss of on-time). A STAG 300 combined cycle (made by General Electric) burning #2 fuel oil has had maintenance costs of 3.5 mills/kWh over the first third of the 1980s.

Options open to utilities in the future: (1) default and go the way of railroads, (2) compete by investing in new technologies, (3) compete by promoting conservation and cogeneration, (4) compete by undertaking powerplant life extension programs.*

Discussion Highlights: Graham stated that when first installed, Dow's Pratt and Whitney turbines experienced a start-up problem -- a gas-generator bearing failure. But since only 8-16 hours are required to replace the gas generator, the percentage of the time the system remained on-line even in this start-up period was high.

Also Graham pointed out that the Dow units were base-loaded. The longest period between rebuild of the gas generator of the DOW FT4 was 18,000 hours. The average was 16,000 hours. Dow Texas has Westinghouse 501s (and used 301s before that). They claim lower maintenance costs on industrial units (compared to aero-derivative units), most likely because of higher capacity factors.

Yosh indicated that JCP&L's simple-cycle gas turbine O&M cost of 10-15 mills/kWh is based on operation of Westinghouse 501AA, 251AA, GE Frame 5, and Frame 7 machines over about 15 years. Being peaking units, these machines typically operated at capacity factors of 3-4%, so considerable O&M cost is distributed over very few kWh's. Yosh also said that downtime is signficantly longer for these industrial units, since field repairs are required rather than shop repairs. Esposito added that JCP&L bought gas turbine units as first of a kind, so "immaturity" factors were encountered, leading to higher O&M costs. He also stated that the longer downtime for industrial units compared to aircraft units is typical of many utilities' experience.

4.5. Operating Availability

The panel consisted of Michael Curley (North American Electric Reliability Council), Charles Graham (formerly Dow Chemical), Steve

* Preliminary estimates of the incremental cost to extend life of a 1950s plant are 3 mills/kWh additional O&M costs plus $50-150/kW one-time costs.

Stephanidis (Allison Gas Turbines), and Don Wood (International Power Technology). Presentations were made by Curley and Wood.

Michael Curley, North American Electric Reliability Council: Curley made statistical comparisons (see Figs. 4.17-4.20 for the definitions of terms used by the NERC) of heavy-duty industrial turbines (called gas turbines in this presentation), aero-derivative gas turbines (called jet engines in this presentation), and combined cycles, based on data for 1982-84 collected by NERC and published annually in their Generating Availability Data Systems report.

The NERC statistics cover: 571 gas turbines in 85 utilities, ranging from 1 to 158 MW; 325 jet engines, in 41 utilities, ranging from 7 to 147 MW, and 25 combined cycles, in 13 utilities, ranging from 68 to 587 MW. Nearly 90% of the gas turbines and 78% of the jet engines are operated on weekdays only (weekly startup), while the combined cycles are predominantly operated continuously with load following capabilities (periodic startup) (Fig. 4.21). Nine gas turbines and no jet engines are operated near or at maximum capability continuously (baseloaded). Due to the small number of combined cycles for which data have been obtained, these data may be somewhat uncertain. The equivalent availability factors (EAF) for all three types of units are virtually the same (Fig. 4.22). Figure 4.23 shows that the EAFs for gas turbines and jet engines are relatively insensitive to type of loading, and are all around 90% or above, while for the gas turbine portion of the combined cycles the EAF is lower for base- and periodic-loaded units.

The difference between EAFs of gas turbines and jet engines on the one hand and combined cycles on the other is accentuated when the total units are considered, e.g., including the steam turbine portion of the combined cycle (Fig. 4.24). Six of the top ten outage problems for weekly-start gas turbines and jet engines are identical. The causes in order of outage hours resulting, are given in Table 4.8.

Table 4.8. Top ten causes of gas turbine and jet engine powerplant outages.

Gas Turbine	Jet Engines
Inspection	Miscellaneous
Turbine	Control and instrumentation
Miscellaneous	Inspection
Overhaul	Hot end inspection
Vibration	Overhaul
Hot end inspection	Fuel system
Fuel supply system	Engine vibration
Starting motor	Engine exchange
Exhaust chamber, hood and vanes	Fire in unit
Compressor	Combustors

Definitions

Operation and Outage

Available
The status of a unit or major piece of equipment which is capable of service, whether or not it is actually in service.

Forced (Unplanned) Outage
The occurrence of an unplanned component failure or other condition which requires that the unit be removed from service immediately or up to and including the very next weekend.

Maintenance Outage
The removal of a unit from service to perform work on specific components which could have been deferred beyond the very next weekend but requires that the unit be removed from service before the next planned outage. This is work done to prevent a potential forced (unplanned) outage and which could not be postponed from season to season.

Noncurtailing Equipment Outage
The removal of a specific component from service for repair, which causes no reduction in unit load carrying capability.

Outage or Derating Cause
A component failure, preventive maintenance or other condition which requires that the unit or a component be taken out of service (outage) or run at a reduced capacity (derating).

Planned Derating
The occurrence of the removal of a component for scheduled repairs (planned or deferred) or inspection which requires that the load on the unit be reduced but where this reduction could be postponed past the very next weekend. See Footnote.

Planned Outage
The removal of a unit from service for inspection and/or general overhaul of one or more major equipment groups. This work is usually scheduled well in advance (e.g., annual boiler overhaul, five-year turbine overhaul).

Reserve Shutdown
The removal of a unit from service for economy or similar reasons. This status continues as long as the unit is out but available for operation.

Scheduled Outages
Scheduled outages are a combination of nonconcurrent maintenance and planned outages.

Unavailable
The status of any major piece of equipment which renders it inoperable because of the failure of a component, work being performed, or other adverse conditions.

Unplanned Derating
The occurrence of an unplanned component failure (immediate, delayed, postponed) or other condition which requires that the load on the unit be reduced immediately or up to and including the very next weekend. See Footnote.

Note:
Deratings which reduce a unit's capability by more than 2% of its Gross MDC and are more than 30 minutes in duration are to be reported. Reporting of lesser deratings is optional. All reported deratings are considered regardless of their time span or derating level.

Fig. 4.17

Definitions

Time

Available Hours—AH
The time in hours during which a unit or major equipment is available; SH + RSH + Pumping Hours + Synchronous Condensing Hours, or PH − [FØH + MØH + PØH].

Equivalent Planned Derated Hours—EPDH
[Planned Derated Hours x Size of Reduction/MDC]

Equivalent Unplanned Derated Hours—EUDH
[Unplanned Derated Hours x Size of Reduction/MDC]

Forced (Unplanned) Outage Hours—FØH
The time in hours during which a unit or major equipment was unavailable due to a Forced (Unplanned) Outage.

Maintenance Outage Hours—MØH
The time in hours during which a unit or major equipment is unavailable due to a Maintenance Outage.

Man Hours (Manhours Worked)—MH
The total number of manhours worked on or off site to accomplish repairs.

Period Hours—PH
The clock hours in the period under consideration (generally one year).

Planned Outage Hours—PØH
The time in hours during which a unit or major equipment was unavailable due to a Planned Outage.

Planned Derated Hours—PDH
The time in hours during which a unit or major equipment was unavailable for full load due to a Planned Derating.

Reserve Shutdown Hours—RSH
Reserve shutdown duration in hours. Some classes of units are not required to report reserve shutdown hours. Reserve shutdown hours for these units may be computed by subtracting the reported service hours and all full outage hours from the period hours.

Scheduled Outage Hours—SØH
The time in hours during which the unit was unavailable due to Maintenance and Planned Outages, and associated Scheduled Extensions.

Service Hours—SH
The total number of hours the unit was actually operated with breakers closed to the station bus.

Unit Years—UY
This term is the common denominator used to normalize data from units of the same type with different lengths of service. The following example contains 20 UY of experience from 4 units.

					TOTAL
Unit	A	B	C	D	4
Years in Service	8	3	7	2	20

Unplanned Derated Hours—UDH
The time in hours during which a unit or major equipment was unavailable for full load due to an Unplanned Derating.

Fig. 4.18

Equations

Availability Factor—AF
[AH/PH] x 100 (%)

Equivalent Availability Factor—EAF
[AH—(EUDH + EPDH)]/PH] x 100 (%)

Equivalent Forced Outage Rate—EFOR
(For each unplanned (forced) derating, an equivalent full load outage duration is calculated. The EFOR is computed using the sum of these equivalent full load outage hours and those hours lost due to all Forced Outages.)

[(FØH + EUDH)/(FØH + SH)] x 100 (%)

Forced Outage Factor—FØF
[FØH/PH] x 100 (%)

Forced Outage Incident Rate
[(Forced Incidents)/(Forced + Maintenance + Planned Incidents)] x 100 (%)

Forced Outage Rate—FØR
[FØH/(SH + FØH)] x 100 (%)

Forced Outage Ratio
[FØH/(PH—AH)] x 100 (%)

Gross Capacity Factor—GCF
[(Total Gross Generation in MWh)/(PH x MDC)] x 100 (%)

Output Factor—ØF
[(Total Gross Generation in MWh)/(SH x MDC)] x 100 (%)

Scheduled Outage Factor—SØF
[SØH/PH] x 100 (%)

Service Factor—SF
[SH/PH] x 100 (%)

Starting Failure Ratio
(Number of Starting Failures)/(Total Number of Attempted Starts)

Notes:
- All computed values are rounded to the nearest hundredth. Entries of 0.00 signify the averaged values are less than 0.005.
- Each of these equations are computed using the historical equations established by the electric utility industry.

Fig. 4.19

Equations

Average Number of Occurrences Per Unit Year

$$\text{AVG NO OCC PER UNIT YR} = \frac{\text{NUMBER OF OUTAGE OCCURRENCES}}{\text{NUMBER OF ALL UNIT YEARS REPORTED}}$$

Average MWh Per Unit Year

$$\text{AVG MWH PER UNIT YR} = \frac{\Sigma \text{ OUTAGE HOURS FOR EACH OUTAGE TYPE X MDC (MW)}}{\text{NUMBER OF ALL UNIT YEARS REPORTED}}$$

Average Duration in MWh Per Outage

$$\text{AVG DUR MWH PER OUTAGE} = \frac{\Sigma \text{ OUTAGE HOURS FOR EACH OUTAGE TYPE X MDC (MW)}}{\text{NUMBER OF OUTAGE OCCURRENCES}}$$

Computation Method Discussion

Each of the statistics presented is computed from summaries of the basic data entries required in each equation. The basic data entries are totaled and then divided by the number of unit-years in that data sample. This unit-year averaged basic data entry is then used in computing the statistics shown. Two examples of these computations are shown below:

$$AF = [AH/PH] \times 100\ (\%)$$

Where:

$$AH = \sum_{i=1}^{N} AH_i/N$$

$$PH = \sum_{i=1}^{N} PH_i/N$$

$$EFOR = \frac{FØH + EUDH}{FØH + SH} \times 100\ (\%)$$

Where:

$$FØH = \sum_{i=1}^{N} FØH_i/N$$

$$SH = \sum_{i=1}^{N} SH_i/N$$

$$EUDH = \sum_{i=1}^{N} EUDH_i/N$$

$$EUDH_i = UDH_j \times \frac{(MDC_j \text{ Reduction})}{MDC_j}$$

N = number of unit-years considered
i = an individual unit in any individual year
j = individual derating occurrence

Fig. 4.20

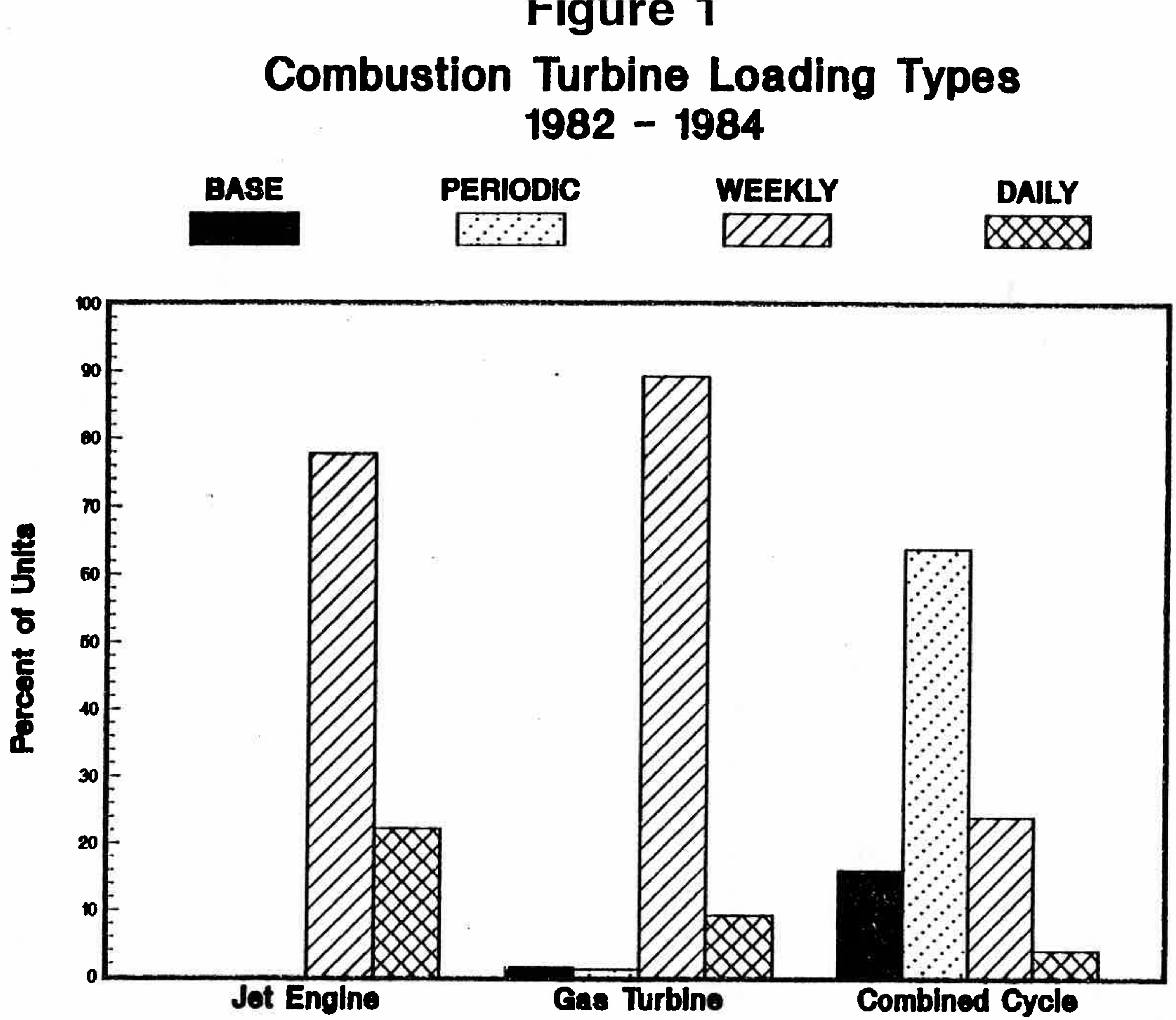


Figure 1
Combustion Turbine Loading Types
1982 - 1984
BASE
PERIODIC
WEEKLY
DAILY
Percent of Units
0
10
20
30
40
50
60
70
80
90
100
Jet Engine
Gas Turbine
Combined Cycle

Fig. 4.21

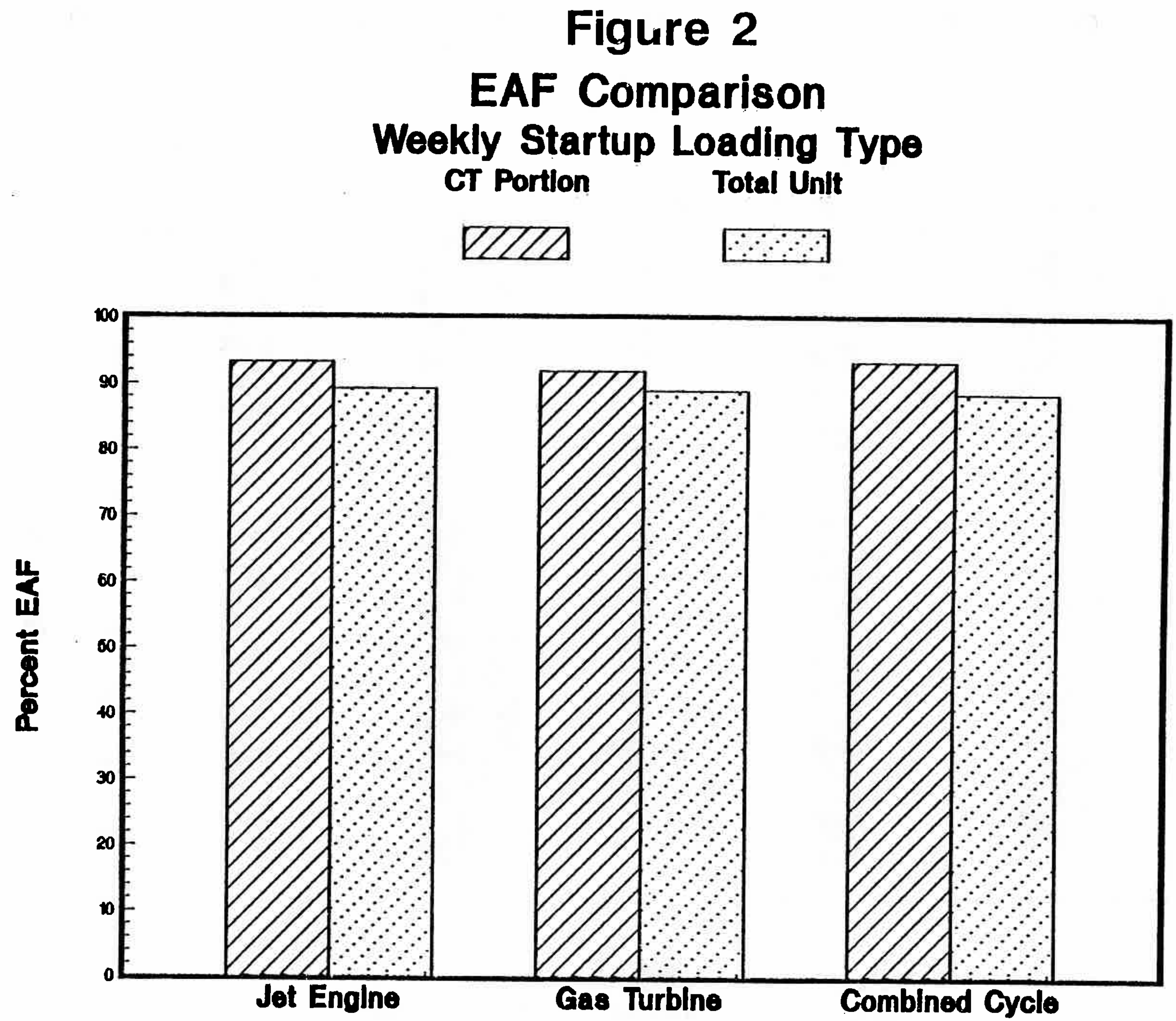


Figure 2
EAF Comparison
Weekly Startup Loading Type
CT Portion
Total Unit
Percent EAF
100
90
80
70
60
50
40
30
20
10
0
Jet Engine
Gas Turbine
Combined Cycle

Fig. 4.22

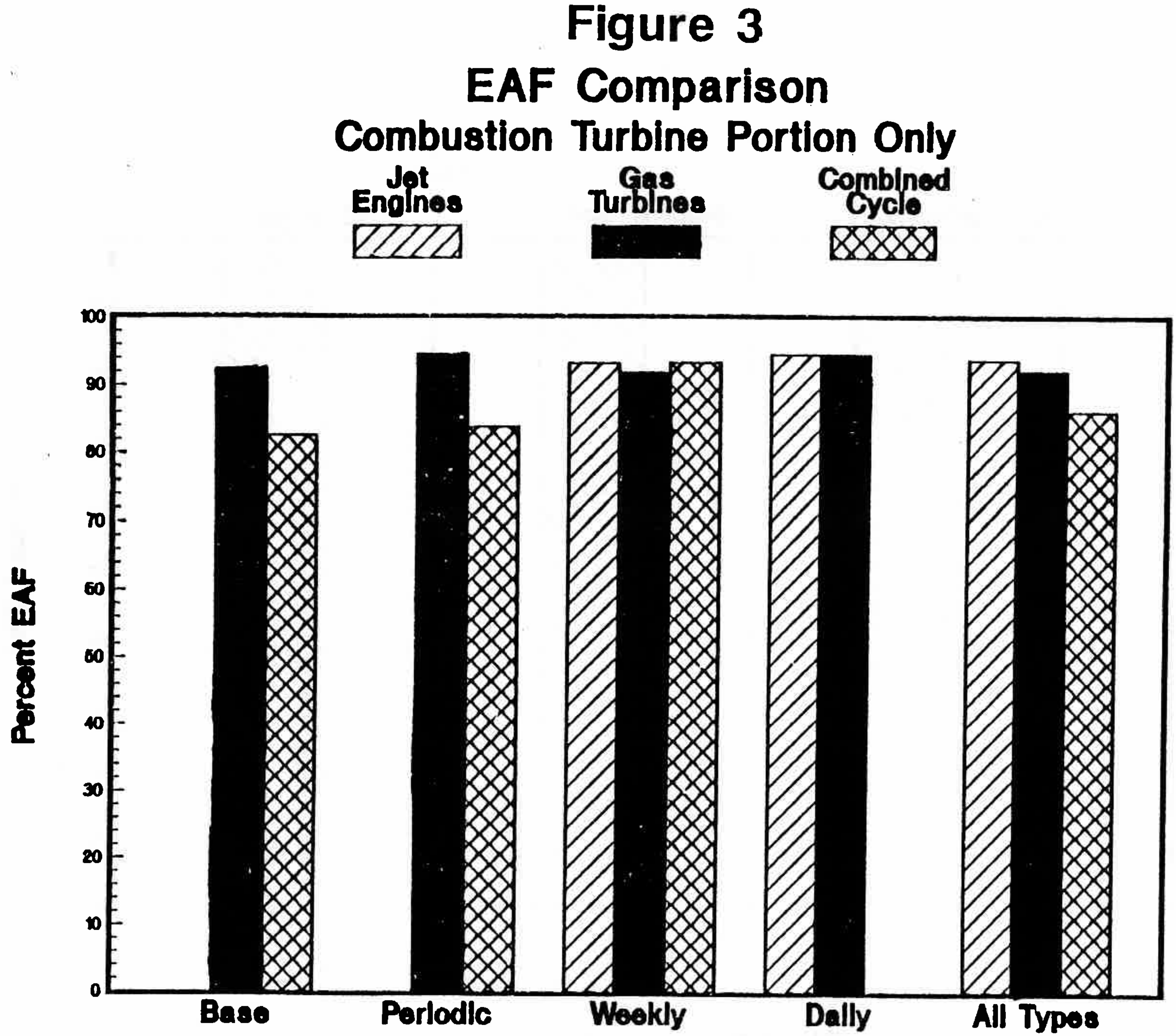


Figure 3
EAF Comparison
Combustion Turbine Portion Only
Jet Engines
Gas Turbines
Combined Cycle
Percent EAF
100
90
80
70
60
50
40
30
20
10
0
Base
Periodic
Weekly
Daily
All Types
Fig. 4.23

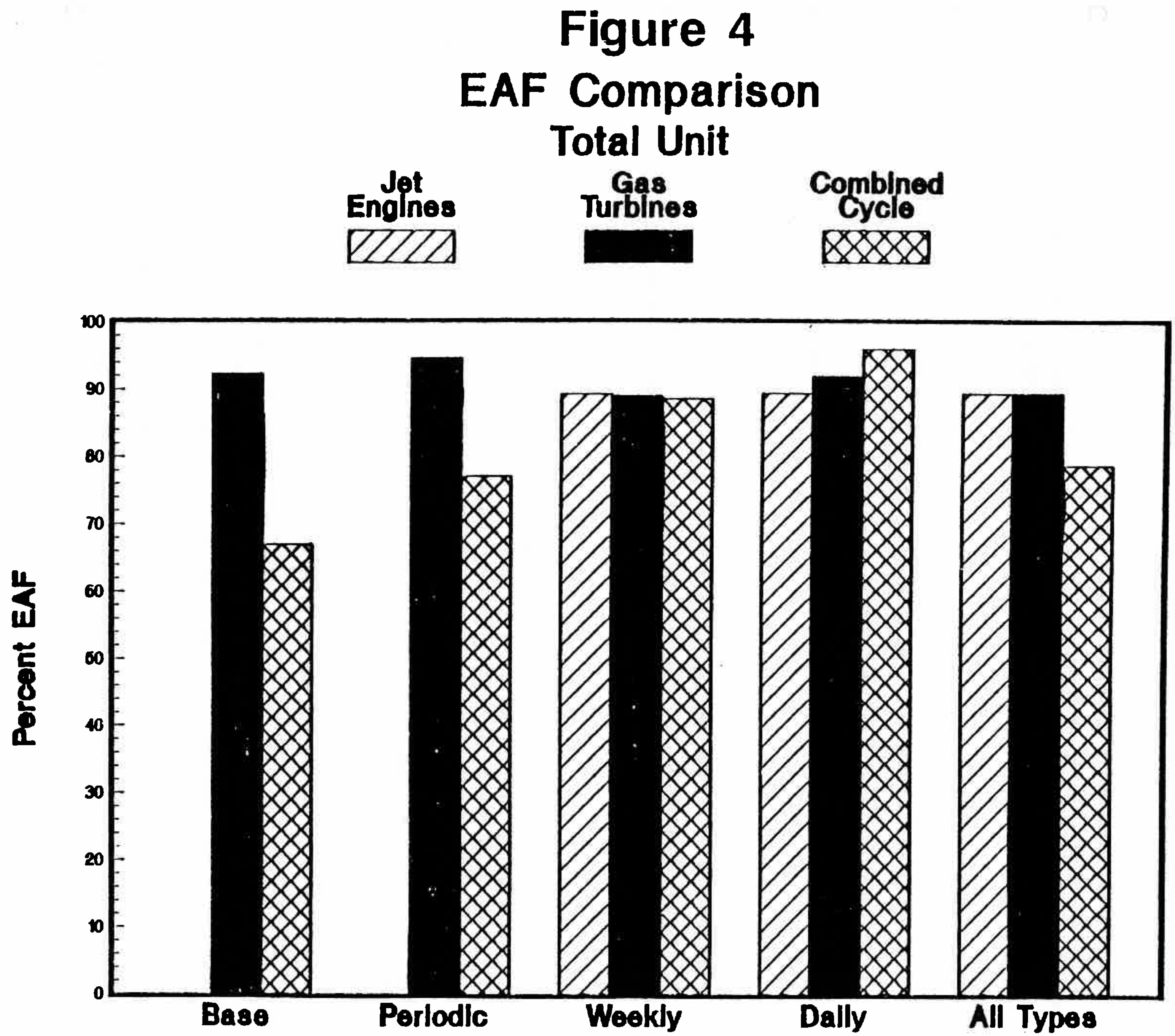


Figure 4
EAF Comparison
Total Unit
Jet Engines
Gas Turbines
Combined Cycle
Percent EAF
100
90
80
70
60
50
40
30
20
10
0
Base
Periodic
Weekly
Daily
All Types

Fig. 4.24

Don Wood, International Power Technology: Wood gave his perspective on the relative availability of STIGs vs other turbine systems, extrapolating from IPT's experience with small (6 MW) units. (IPT holds patents on the optimal (maximum efficiency) STIG configuration, which is characterized by high temperature, pressure, and steam mass flow.) Three factors which affect availability are: (1) system design, (2) O&M practices, and (3) spares policy. STIG has a comparative advantage over other systems with regard to (1) and (3):

(1) The IPT STIG system is designed to be highly flexible, so that a single "cookie cutter" design can be used in a large number of applications. Compared to combined cycles, STIGs have a reduced number of components, and their modulatrity means small increments can be added to a system with less potential for system damage, e.g., by using 6-100 MW units instead of 1-600 MW unit.

(2) STIG is not too different from other systems.

(3) The standard design means spares can be stocked more economically, e.g., at a centralized spares facility serving a number of units.

In the first full year of operation of IPT units, 1985, many problems were encountered, including water problems. Despite this, operating availability was a respectable 84%. In the long term, they expect an availability of 92-94%.

Wood's basic STIG development philosophy is to start small and work up to utility-sized applications. IPT is now working with a Japanese consortium interested in developing a utility-sized STIG system. Wood is confident that a utility STIG system will be developed.

4.6. Long-Term Reliability

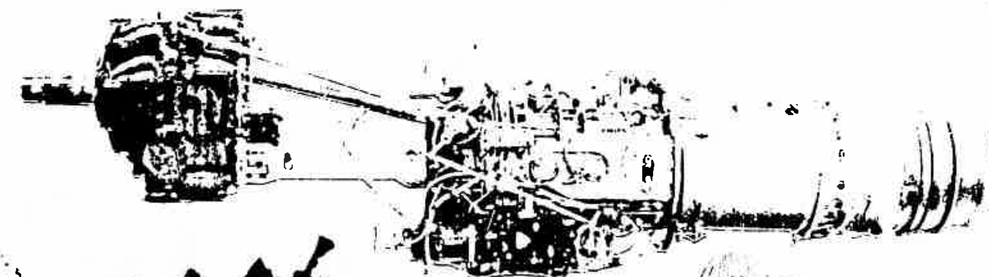
The panel consisted of Michael Curley (North American Electric Reliability Council), Ralph Kidder (Allison Gas Turbines), and Charles (formerly Dow Chemical). A presentation was made by Kidder.

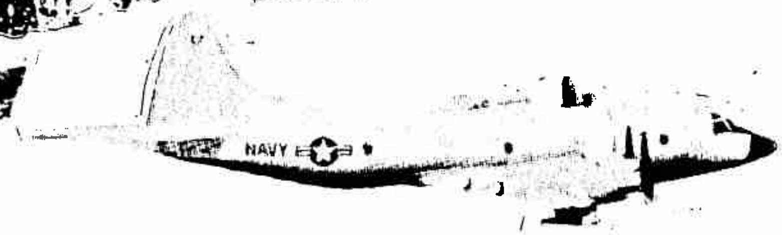
Ralph Kidder, Allison Gas Turbines: The Allison 501-K engine is derived from the T56 engine, which is used in a wide range of military applications (Fig. 4.25). T56 engines are now pulled "on condition," not on hours run. The 501-K (Fig. 4.26) has a broad surge margin over a wide range of operating conditions. The combustors are characterized by high efficiencies and low emissions. The turbines use air cooling and high-strength materials to keep airfoil metal temperatures and gradients low, while providing high structural strength. Recently offered products based on the 501-K include the 501-KM (with external combustor) and the 501-KH (with steam-injection capability -- Fig. 4.27).

The wide performance envelope of the 501-KH is shown in Fig. 4.28. Only steam must be injected (no water droplets), and the water quality must be better than the fuel quality requirements. In experimental work, the

Allison GM

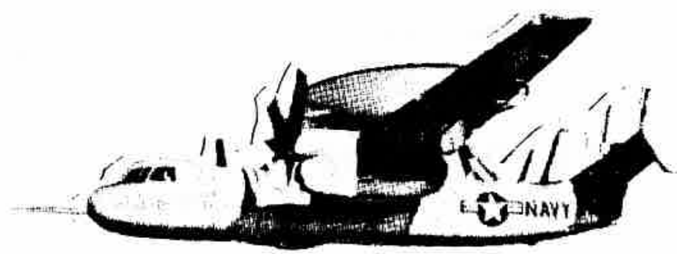
T56 MILITARY APPLICATIONS





LOCKHEED P-3
472 INVENTORY AIRCRAFT

LOCKHEED C-130
857 INVENTORY AIRCRAFT



GRUMMAN C-2
12 INVENTORY AIRCRAFT

GRUMMAN E-2
108 INVENTORY AIRCRAFT

Fig. 4.25

Allison

501-K ENGINE CROSS SECTION

(SINGLE SHAFT)

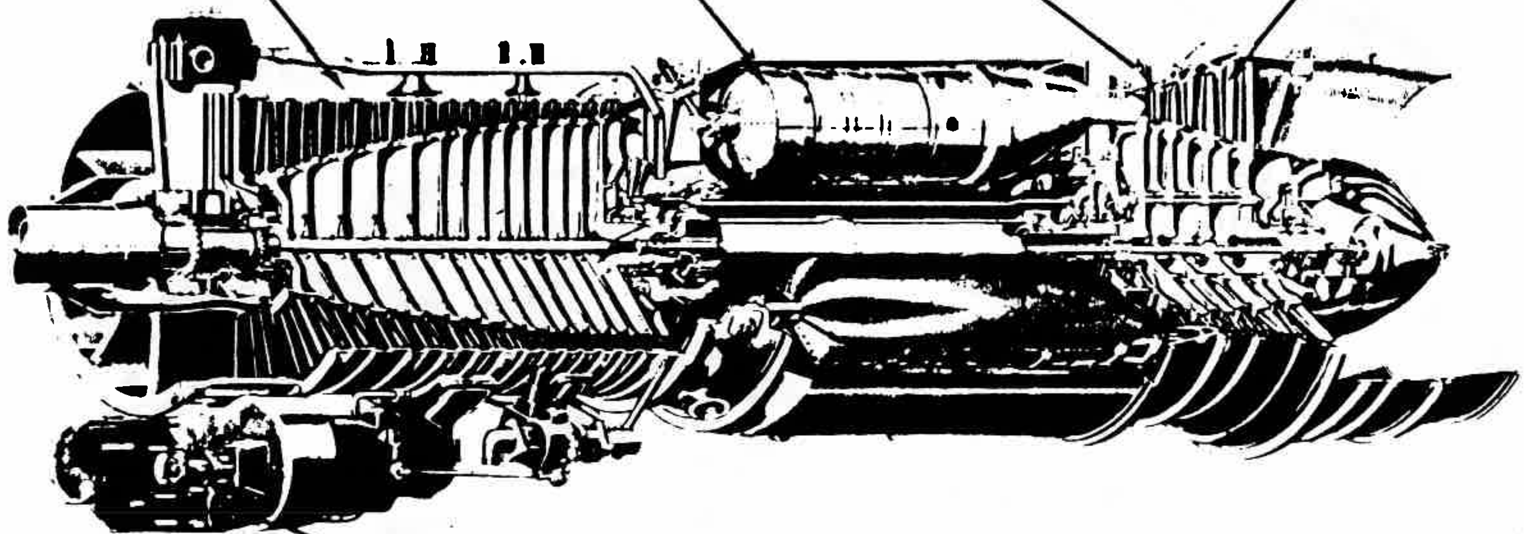


Fig. 4.26

ALLISON INDUSTRIAL GAS TURBINES

NEW PRODUCTS

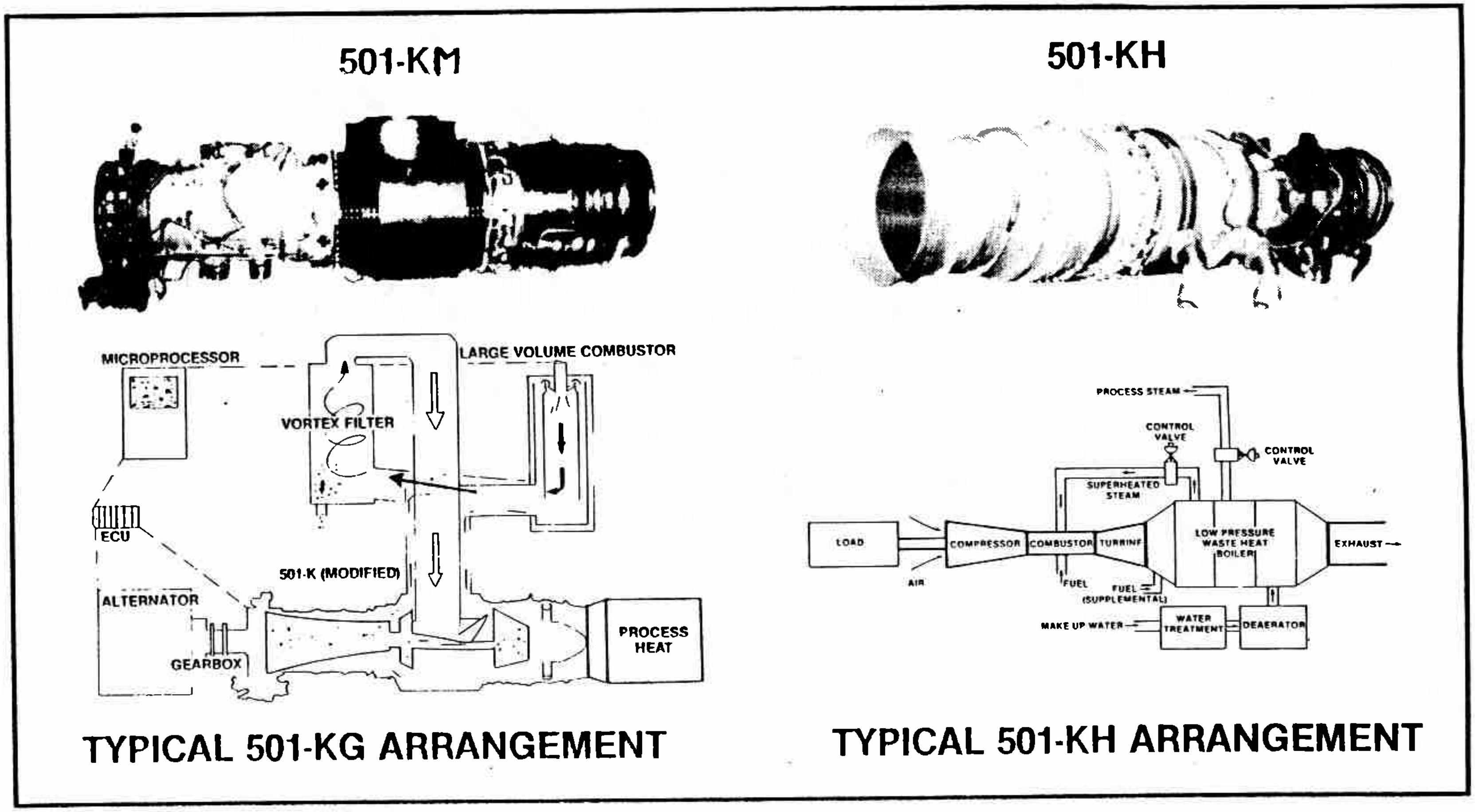


Fig. 4.27

ESTIMATED 501-KH PERFORMANCE*

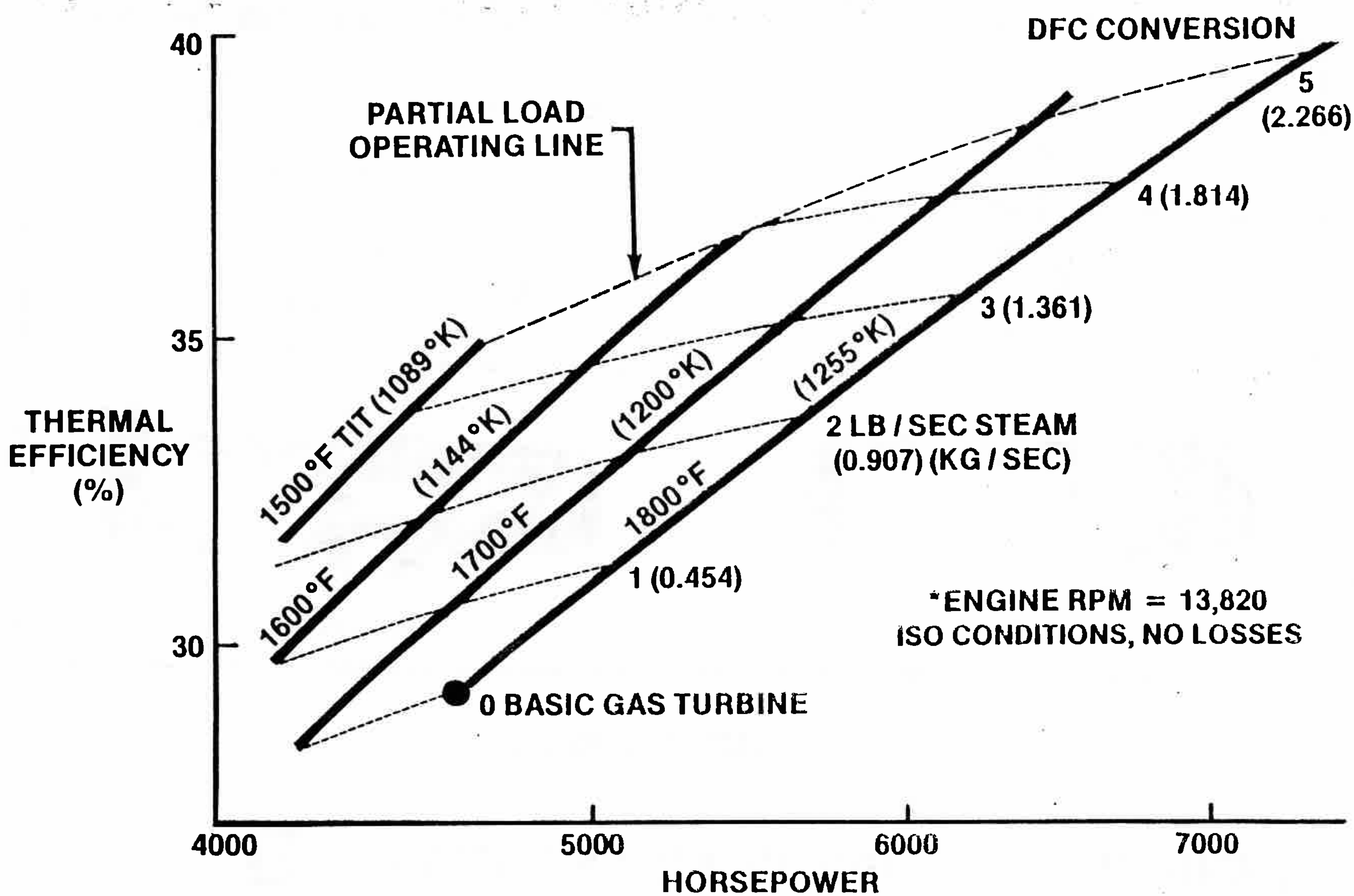


Fig. 4.28

injection of superheated steam led to a $75^{\circ}F$ rise in temperature of the first stage blade (measured by optical pyrometry), for a TIT of $1800^{\circ}F$ and maximum steam flow. This finding suggests that it may be necessary to operate at a sub-rated firing temperature to maintain life or to add higher strength material. Potential transient-related problems with steam injection include compressor surge/combustor flame out upon raising of steam flow, engine over-temperature upon decreasing the steam flow, and engine overspeed if steam flow is not shut off quickly enough.

If all steam is going to cogeneration, additional water injection may be needed for NOx control. The effect of steam/water injection on long-term reliability is under review.

The primary water-related problem in STIG units is sulfidation. Little problem with deposition has been encountered. Up to 17% steam can be injected in the 501-KH.

4.7. Coal Gasifiers and STIGs

The panel consisted of Wieble Alley (Arkansas Power and Light), Clint Ashworth (Pacific Gas and Electric), and James Corman (General Electric). A presentation was made by Corman.

James Corman, General Electric: General Electric is studying alternative concepts for utilizing integrated gasification coal conversion (IGCC) with gas turbines, which would permit environmentally acceptable use of a low cost fuel -- coal -- in low-capital cost power generating equipment -- gas turbines. The overall objective of the study is to develop a relatively small system (50-100 MW) that would be competitive with larger coal-to-electricity systems, but which would have reduced equipment and construction costs. The basic process is depicted in Fig. 4.29.

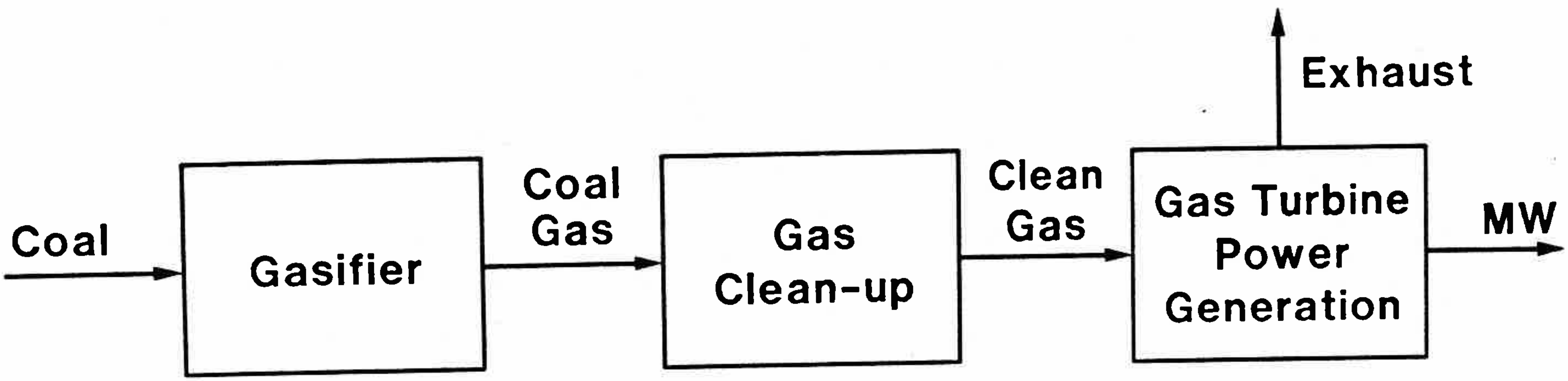
The Cool Water Plant in California, the only commercially operated IGCC, utilizes an oxygen-blown Texaco gasifier to produce a medium-BTU gas from coal (at about $2400^{\circ}F$), which is then cooled and cleaned in a relatively low temperature process (Fig. 4.30).

GE is studying simplifying alternatives, including (1) use of an air-blown gasifier, (2) elimination of gas cooling through use of a hot-gas clean-up process, and (3) elimination of the steam turbine through use of a steam-injected gas turbine. A simplified schematic of such a system is shown in Fig. 4.31. The key components of such a system are the air-blown gasifier, a hot-gas clean-up process, and an efficient power generator. The major developmental work required is for a hot-gas clean-up process.

Four specific IGCC gas-turbine based plant configurations operating with air gasifiers and hot-gas clean up were assessed:

(1) Lurgi gasifier/Frame 7E combined cycle (currently available)
(2) Lurgi gasifier/Frame 7F combined cycle (advanced unit, now offered)
(3) Lurgi gasifier/LM-5000 STIG (currently available)
(4) Lurgi gasifier/Advanced LM-5000 STIG (ISTIG)

IGCC
PROCESS SCHEMATIC



Function:	**Function:**	**Function:**
- Ash Rejection - Conversion Of Solid Coal To Gaseous Fuel	- Gas Turbine and Environmentally Compatible Fuel	- Power Generation

Fig. 4.29

COOL WATER IGCC

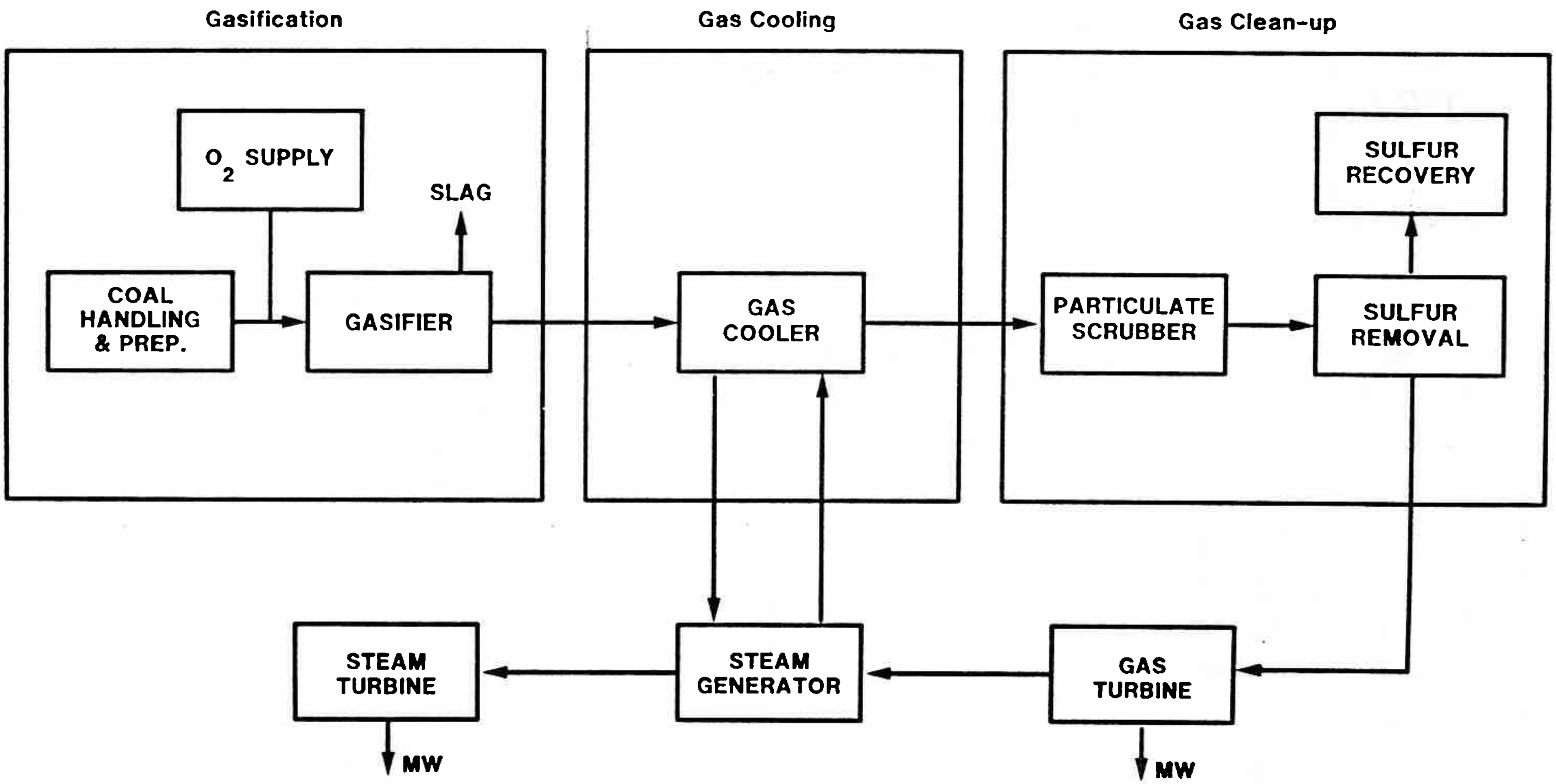


Fig. 4.30

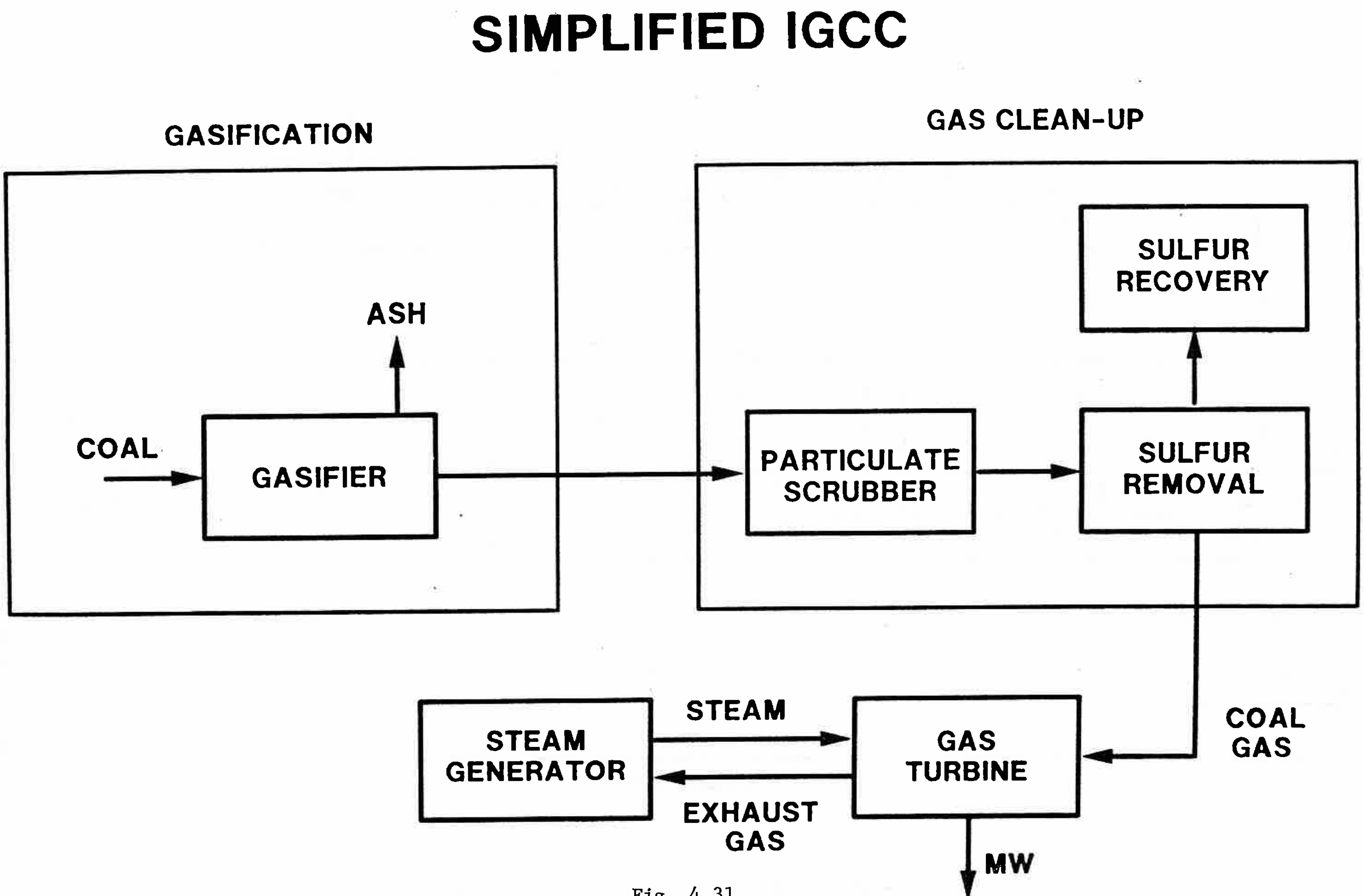

SIMPLIFIED IGCC
GASIFICATION
GAS CLEAN-UP
ASH
COAL
GASIFIER
PARTICULATE SCRUBBER
SULFUR RECOVERY
SULFUR REMOVAL
COAL GAS
STEAM GENERATOR
STEAM
EXHAUST GAS
GAS TURBINE
MW

Fig. 4.31

In addition, a system incorporating a BGC oxygen gasifier an the advanced combined cycle was also considered. The performance of all 5 systems, which was optimized for efficiency, are shown in Fig. 4.32.

In the analysis, the Lurgi/LM-5000 ISTIG system was the most efficient (42.1%, LHV), followed in order by the BGC gasifier/Frame 7F combined cycle (38.8%), the Lurgi/Frame 7F combined cycle (37.3%), the Lurgi/LM-5000 STIG (35.8%), and the Lurgi/Frame 7E combined cycle (35.7%). To obtain these efficiencies with the combined cycles requires a plant capacity of 450-550 MW. The maximum STIG and ISTIG plant efficiencies are reached with plant capacities of 50-100 MW.

In summary, gas-turbine based powerplants with integrated air-blown gasifiers could have excellent efficiency in small sizes with relatively simple configurations (contributing to shorter construction times). In addition, such systems present opportunities for continued evolution. The technologies required for these systems include a hot-gas clean-up system with tight fuel plant/power generation integration, and air-blown high pressure gasifiers.

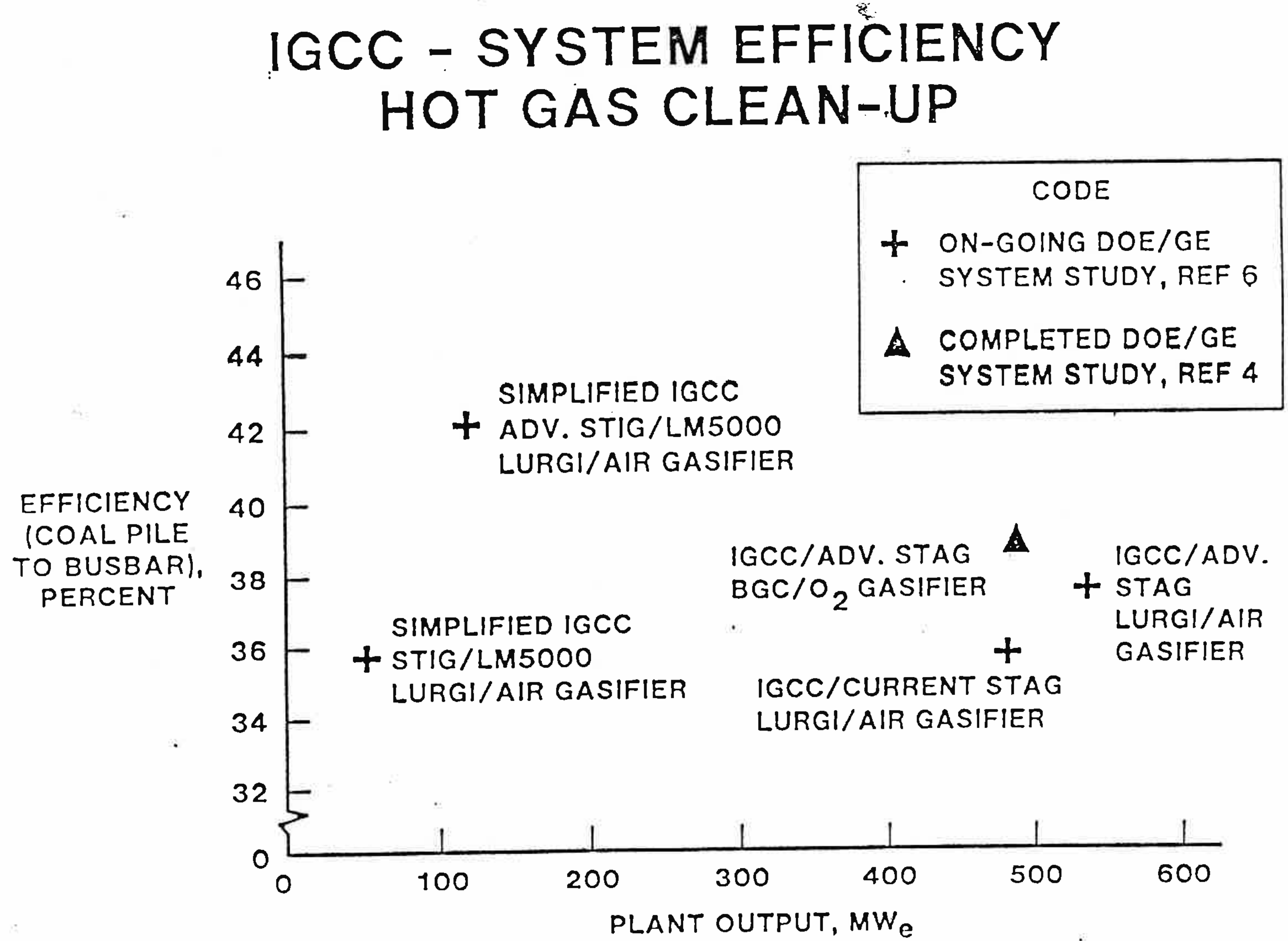
Discussion Highlights: Ashworth stated that utilities now view gasified coal as a good back up for natural gas, whereas it would not have even been considered 10 years ago. With coal gas as a back-up, "phased construction" becomes possible -- building natural gas-fired plants now and converting to coal at a later date. This can lead to (a) savings in capital cost, (b) addition to the generating base in small increments, and (c) deferred investment in coal facilities.

Alley indicated that a careful comparative study should be made to assess the relative merits of the integrated gasification/power generation system described by Corman and the alternative of centralized gasification plus dispersed power generation/cogeneration (such as the scheme which AP&L has been exploring).

A major advantage of low BTU gas is that it does not require an oxygen plant, which would roughly double the cost of the plant. Corman indicated that GE thinks gas with a heating value as low as 100-110 BTU/cubic foot can be used in their turbines. (The Lurgi gasifier would produce 160-180 BTU/cf.) GE is operating a 24 ton/day gasification facility in Schenectady on Pittsburgh #8, #9 and Illinois #6 coals. In their experiments, with agitation of the bed, the heating value of the gas varied ± 5%, and no caking problems were encountered.

Corman indicated that the cost of cyclones would not be large (about $10/kW). A solid absorption/hot-gas clean-up system may require recycling of solids to keep the cost down, but such a system is not likely to be a big part of the total plant cost.

Robert Williams (Princeton University) asked whether it wouldn't be better to base gasification development on medium BTU gasifiers instead of low BTU gasifiers, since the potential uses of low BTU gas are limited (mainly for power generation in closely coupled gasifier/power production



IGCC - SYSTEM EFFICIENCY
HOT GAS CLEAN-UP
CODE
ON-GOING DOE/GE SYSTEM STUDY, REF 6
COMPLETED DOE/GE SYSTEM STUDY, REF 4
EFFICIENCY (COAL PILE TO BUSBAR), PERCENT
46
44
42
40
38
36
34
32
0
0
100
200
300
400
500
600
PLANT OUTPUT, MW_e
SIMPLIFIED IGCC ADV. STIG/LM5000 LURGI/AIR GASIFIER
SIMPLIFIED IGCC STIG/LM5000 LURGI/AIR GASIFIER
IGCC/ADV. STAG BGC/O_2 GASIFIER
IGCC/CURRENT STAG LURGI/AIR GASIFIER
IGCC/ADV. STAG LURGI/AIR GASIFIER

Fig. 4.32

units), while medium BTU gas can be used for many purposes (e.g., as a feedstock for making methanol, ammonia, and various other chemicals, and as a gas that can be distributed relatively long distances in pipelines to a variety of users).

Corman responded that in their evaluations, GE assumed utilities would want systems for producing power only. Alley pointed out that given the current state of utilities, they may be interested in diversified uses.

Corman noted that external combustors are not considered for GE turbines because GE makes only large gas turbines and for such units a uniform combustion-gas distribution is difficult to achieve at high temperatures (greater than 2000°F). However, GE is looking at direct firing using a pressurized fluidized bed combustor. The turbine inlet temperature would be 1600-1700°F. Burkett added that ASEA-STAL is quite active in developing directly-fired PFBC gas-turbine systems.

4.8. Institutional Issues

The panel consisted of Ken Deffeyes (Princeton University), Gary Edinger (New Jersey Natural Gas), Nicholas Esposito (Jersey Central Power and Light), Steven Gabel (New Jersey Board of Public Utilities), Mike German (American Gas Association), Bruce Grossman (South Jersey Gas), Edward Linky (New Jersey Department of Energy), Bharat Patel (New Jersey Department of Energy), Howard Solganick (Atlantic City Electric), Robert Williams (Princeton University), and Joe Wilson (Elizabethtown Gas). Presentations were made by German and Deffeyes.

Michael German, American Gas Association: German began with a history of natural gas prices, pointing out that from the 1950's to the early 1970's price controls had the effect of contracting supply and increasing demand. He argued that these price controls were responsible for the natural gas supply shortage of the mid-1970s and the associated rapid increase in prices at that time.

Now in the mid-1980's there is a gas surplus. We are in fact in the 7th year of what was once envisaged as an 18-month "gas bubble." The price of gas is about $1.58/MBtu at the wellhead. The delivered price of gas is less than that of coal. But since the price has been largely decontrolled, the market in time will bring supply and demand into balance, because prices are falling, demand is increasing, and supplies are tightening -- the supply surplus will not persist.

German argued that the long term outlook for gas was good, however. The American Gas Association (AGA) projects that the average retail price of gas will fall about 3% per year (in inflation-corrected terms) until 1990 and will then rise about 1/2% per year until 2000, based on constant refinery acquisition cost of crude oil of $25 per bbl through 1990 and a 2% per year real increase until 2000. The AGA projects that domestic production of natural gas in the year 2000 will be about 18 trillion cubic feet. For comparison, production in 1984 was 17 trillion cubic feet.

US proved reserves of natural gas amount to about a 10 year supply at the current consumption rate (Fig. 4.33). German pointed out that the phasing out of price controls on new gas has had the effect that recent yearly additions to proved reserves have been comparable to annual production, in contrast to the low rate of reserve additions in the mid 1970's (Fig. 4.34). The estimates of remaining ultimately recoverable US (lower 48 states plus Alaska) natural gas resources (reserves plus estimated additional probable, possible, and speculative resources) are about a 50 year supply at the present consumption rate, according to the Potential Gas Committee. However, as pointed out by German, this Committee's estimate of potential additions to reserves for the lower 48 states was about the same in 1984 as it was in 1966, despite the fact that in the intervening 18 year period natural gas consumption in the US amounted to more than half of this total, as shown in Table 4.9. Higher prices and improvements in technology have led to upward adjustments of estimates of the amount of gas that might be ultimately recoverable. German said he believes that without price controls this trend will continue, pointing out that the physical amount of natural gas in place is enormous, amounting to a thousand years supply or more if geopressurized gas resources are included.

Table 4.9. Potential additions to natural gas reserves, lower 48 states.*

	(trillion cubic feet)			
	Probable	Possible	Speculative	Total
As of 12-31-66	300	210	180	690
As of 12-31-68	238	317	245	800
As of 12-31-70	218	326	307	851
As of 12-31-72	212	290	278	780
As of 12-31-76	192	318	188 to 238	698 to 748
As of 12-31-78	186	359	285	830
As of 12-31-80	185	329	254	768
As of 12-31-82	184	326	232	742
As of 12-31-84	176	264	207	647

For comparison, the cumulative production in the US was 358 trillion cubic feet in the period 1966-1984.

* Source: Potential Gas Committee, "Potential Supply of Natural Gas in the United States (December 31, 1984)," Potential Gas Agency, Colorado School of Mines, Golden, Colorado, June 1985.

The present state of gas industry regulations is that producers are unregulated, pipeline carriers are highly regulated at the federal level, and distributors are highly regulated at the state or local level. Some effects of regulation on gas prices include low prices to residential and commercial costumers, subsidized by high prices to large industrial users. Rate changes are used to keep the gas system full.

Gas Production vs. Reserve Additions

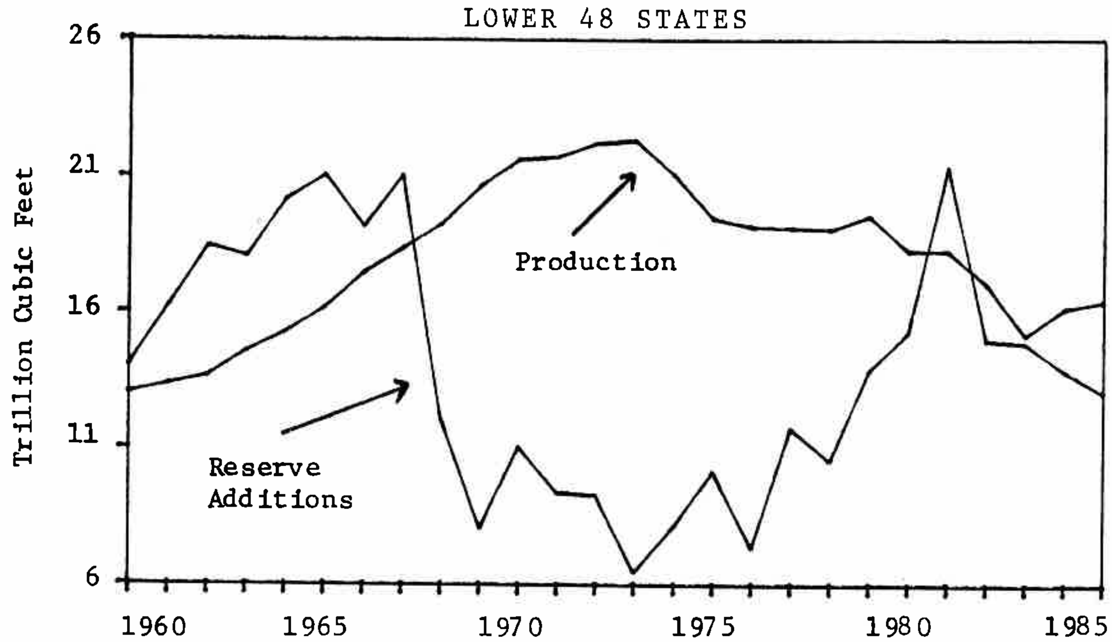


Fig. 4.33 (From [15])

Proved Natural Gas Reserves

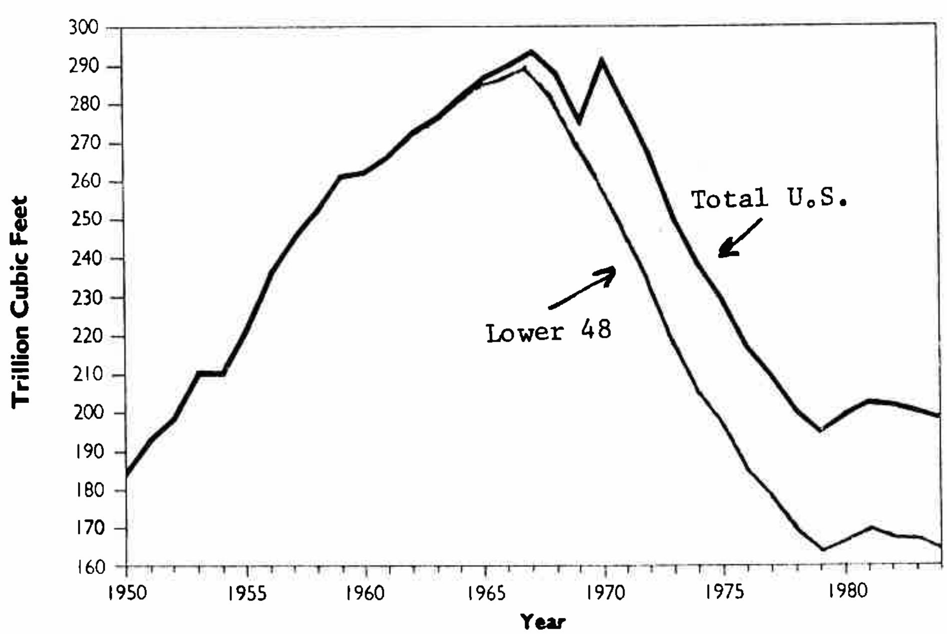


Fig. 4.34 (From [15])

German believes that the Fuel Use Act will be repealed, probably in 1986. There have been 100 exemptions to the Fuel Use Act to date, and exemptions are easily obtained.

German pointed out that STIG and ISTIG technologies, as well as combined cycle technologies are well suited for coping with environmental concerns, as they would be effective in coping with the acid rain problem.

Ken Deffeyes, Geology Department, Princeton University: Serious looking for oil has been going on for about 100 years, serious looking for gas for about 10 years. This suggests there is a sharp learning curve and that the supply of gas is more expandable than oil.

During the oil crises in the 1970's, a lot was learned about geological formations holding natural gas. Many were too deep and too hot to drill then, but they are starting to be exploited now.

A graph of the world's oil and gas reserves for 18 countries with the largest resources (Fig. 4.35) indicates that the US, Mexico and Canada all have significant resources. Also, since the USSR has the largest gas reserves in the world (about 40% of the total), US wheat might one day be traded for Soviet gas.

Discussion Highlights: Patel described the New Jersey energy supply picture. The current supply includes about 60% oil, 19% gas. The recent New Jersey Department of Energy Master Plan calls for less dependence on oil through increased use of natural gas and coal. It pushes for more natural gas use and more cogeneration (see Appendix D). Two bills were recently signed in New Jersey to exempt cogenerators from taxes on natural gas.

German stated that it is rare to see policy that treats oil and gas separately. Oil and gas should be treated separately, because the future availability picture is so different. It may be very difficult for gas to displace oil right now because of the low oil prices. Utilities will feel the economic pressure to switch to oil. However, gas prices are falling in response to the oil prices. As this happens, gas will displace utility use of coal and "coal by wire." For combustion turbine systems the fuel competition is primarily between natural gas and distillate fuel oil, not the much cheaper residual fuel oil.

Linky asked German about the health of the gas distribution companies, in particular their ability to survive the current dynamic market. German responded that because of regulated prices, the local distributors and utilities are the most protected part of the gas industry. The gas producers are at most risk from the dynamics of the economy. The utilities would be stronger under a low price scenario than a high price scenario. Since New Jersey has a higher oil penetration now, with less coal and less electric heat, the opportunity for oil is better here, unlike much of the rest of the country.

Grossman described the situation in his company's area. South Jersey

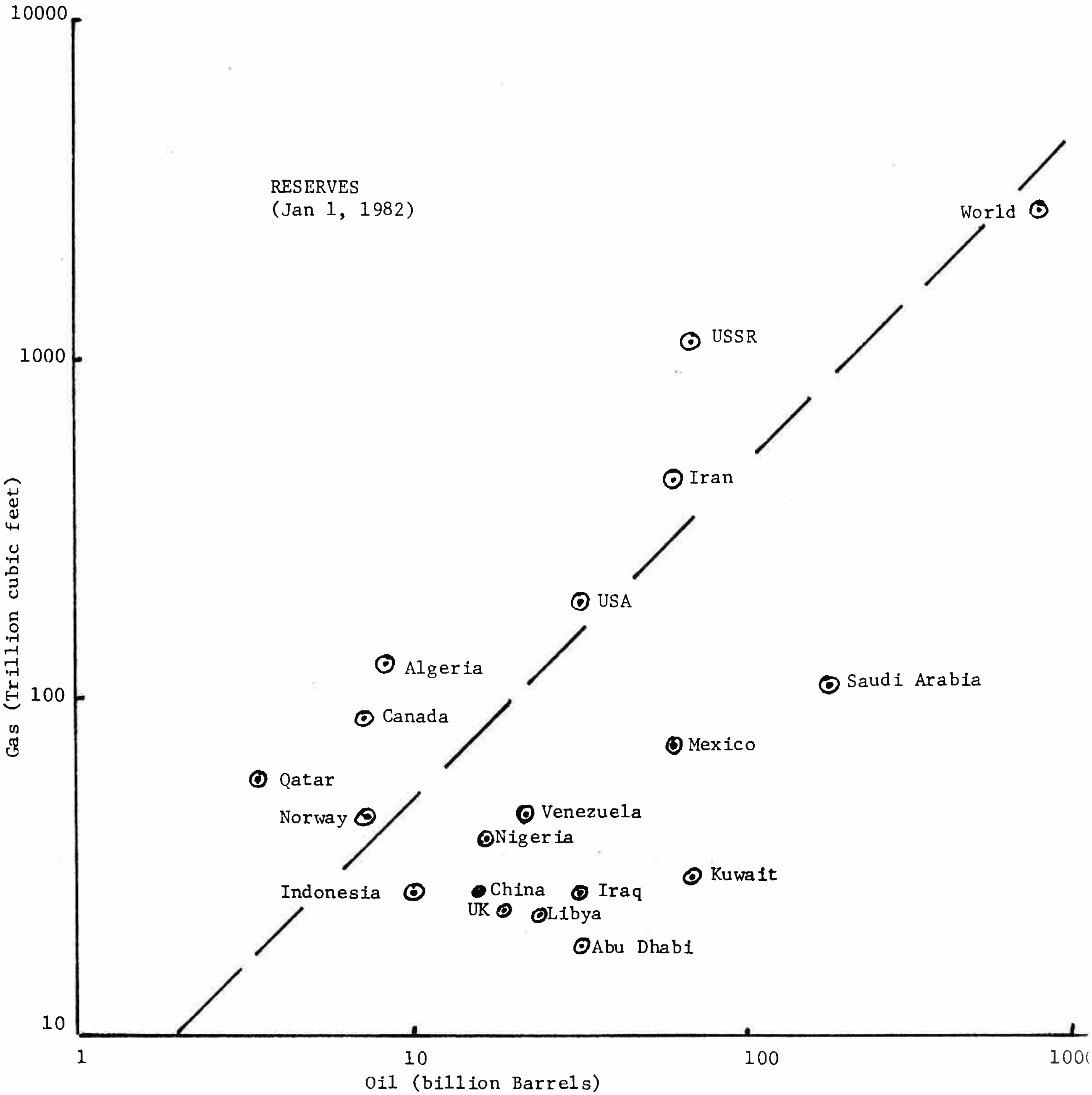

10000
1000
100
10
Gas (Trillion cubic feet)
1
10
100
1000
Oil (billion Barrels)
RESERVES
(Jan 1, 1982)
World
USSR
Iran
USA
Algeria
Canada
Saudi Arabia
Mexico
Qatar
Norway
Venezuela
Nigeria
Kuwait
Indonesia
China
Iraq
UK
Libya
Abu Dhabi

Fig. 4.35

Gas is experiencing rapid residential and commercial growth because of lower interest rates and the casino business. South Jersey Gas is served by an intercontinental pipeline, which is not a common carrier, but a carrier which supplies only utilities. The pipeline company (Transco) has applied to become a common carrier, but the utility is still confident of getting the gas they need, even without long term contracts with the pipeline. Utility customers would like to be locked into a rate, if the pipeline becomes a common carrier. South Jersey Gas is receptive to cogeneration and to serving new customers. If South Jersey Gas doesn't currently serve an area, that doesn't mean they won't make special arrangements to provide gas service.

German noted that three combined cycle generating facilities have negotiated gas supply and prices for the lifetimes of the plants, so that these costs are certain. Such deals can be negotiated. Delivery is not as reliable as supply. Industrial pipelines are advocated because industry doesn't trust regulators. When industrial cogeneration boilers are lower priority than residential heating, industrial users consider building their own pipelines.

Gabel stated that the supply of gas is secure. But what about price, production costs? How much will it cost to bring in this supply? Local gas distributors are trying to maintain high load factors. Gas is marketed at very small margin. The customer who buys cheap gas gives up reliability. A price must be paid for reliability. Regulators think that utilities should pay higher prices for secure supplies. Should the cost of developing new gas supplies be borne by high load customers or should the local distributor pass these on to consumers? German responded that who gets the right to cheap gas will be resolved in the market. Can you get all the gas you want at \$1.50/MBtu? No. Can you get all you want at \$2.50/MBtu? -- German reiterated that shortages are caused by regulation, not resource limitations. Who gets access to pipelines if supplies get tight? In 1976-77 industrial users who paid extra for secure supply still got gas.

At this point Williams raised a different institutional issue, the developmental costs for advanced combustion turbines for central station power generation. Vendors are reluctant to make investments. Questions of outside support or other institutional arrangements might be addressed.

Tuzson stated that gas turbine technologies such as ISTIG would be attractive for utility applications not just because of their high efficiency but also because of other attributes (e.g., cooling towers are not required) . He asked how a gas turbine could be developed for utility use. Overcoming technical problems is not the problem. To develop a new machine suitable for utility applications might require \$100 million. Where might such funding come from? The manufacturers are not a likely source, as military applications tend to have first priority, and this development can't simply be a military spin-off. The effort must be more deliberate. While many users would be interested in a large, efficient gas turbine such as ISTIG, if it were developed, no one company may be able to afford it. A deliberate government or private consortium R&D effort may be required.

Tuzson described a Dutch-funded gas turbine development program supported by revenues from North Sea gas wells. One project was a small regenerative-intercooled gas turbine (10,000 hp, 44% efficiency). While this program was not successfully completed (because alloted development costs of $10-20 million were insufficient and because funds were mismanaged, the program ended with a political scandal), Tuzson felt the basic funding idea was a good one.

Ashworth suggested that the development effort should start with small steps, so that the potential market is always visible to investors. PG+E spent $970,000 and GE several million to get the minor-modified STIG into the cogeneration market. There is not presently a clearly identified market large enough to warrant $100 million development expenditure. He felt that what is required to develop the ISTIG technology is:

(1) a subsidy from somewhere -- probably not the utilities, since ISTIG does not present clear advantages compared to the currently offered advanced combined cycle,

(2) an evolutionary development process -- past experience with, e.g., fusion, breeders, and fuel cells shows that it doesn't work to try to give birth to an adult technology overnight,

(3) a diversified development effort -- perhaps vendors other than GE could develop particular components, e.g., the power turbine or the compressor, and thereby shoulder some of the development cost.

Tuzson noted that a 1 percentage point improvement in a utility system's efficiency would lead to a saving of some $200 million per year. If the development cost were shared by utilities it would pay back handsomely.

Ashworth stated that utilities can't make major committments based on speculation, and ISTIG is speculative. In 1983, PG&E analysis indicated that substituting ISTIG for 2000 MW of other capacity would save $500 million per year by the mid-1990's. This analysis is now worthless.

Robert Socolow (Princeton University) observed that perhaps foreign competition will be needed to spur development.

Wood stated that a utility-scale Cheng-cycle system will be developed. He described IPT's investment of $20 million to develop the 6 MW Cheng-cycle cogeneration system. Some of the funding came from venture capitalists, who have a total of about a billion dollars invested in various new technologies. He said that a development cost of $100 million is really not a lot of money, considering the stakes involved. IPT, having talked to GE for 11 years without success, has now turned to a Japanese firm that is organizing financing for the development of a utility sized Cheng-cycle system. He suggested that if the technology is to be developed in the US, a group of utilities should pool resources, with each making a relatively small investment that it can afford to lose.

Robson noted that in the development history of gas turbines, there were significant military contracts to companies like United Technologies, General Dynamics, Lockheed, and McDonnell-Douglas to develop jet engines. The flow of money then spread to commercial aircraft development. In the past, utility machines could be gotten without extra upfront money, since the development of utility machines was a direct spin-off of the military work. However, ISTIG is a machine which requires upfront development money, as there are no military or aircraft applications; it cannot be easily spun-off of aircraft technology. And from the perspective of the manufacturer, the military market is firm, the utility market uncertain. The manufacturer is not likely to gamble its financial and manpower resources on an uncertain utility market. United Technologies developed a highly efficient gas turbine in the mid-70's. But there was no market, and so they lost this R&D investment. Today United Technologies is not willing to take such a risk. But if a consortium of utilities were to guarantee an order of 30-40 engines, development would proceed.

Williams noted that the market for ISTIG does not appear to exist because of excess capacity, but there may be a significant market for replacing existing capacity. If the price of gas is greater than $3.00 to 3.50/MBTU, it would make sense to build ISTIG plants to replace existing gas-fired steam plants, as it would lead to an overall reduction in the cost of electricity. This potential replacement market would be the equivalent of some 400 ISTIG units, which ought to be enough to attract the interest of manufacturers. But the regulatory framework does not encourage utilities to replace existing capacity even though so doing would be economically efficient. Providing utilities incentives to operate with greater economic efficiency may be worth exploring.

Grossman indicated that the utilities are involved in their own R&D programs or in conjunction with EPRI. They recognize that a fixed cost investment can be offset by fuel savings when converting to gas. Gabel noted that coal conversion has a pay back of about 18 months. And he argued that utilities have incentive to conserve, because they can make more money, and they do have the incentive to optimize economic efficiency.

German noted that there seems to be a perception that development of STIG and ISTIG is not progressing fast enough. He asked whether the rate of development is unduly slow.

Corman responded that there is nothing wrong with the pace of development. The 50 MW STIG is a commercial product. If a utility market is there, a utility product will be developed. The performance of the ISTIG would be about the same as that of the advanced combined cycle, which is already available in the 200 MW size. Utilities must ask themselves how important it is to gain an efficiency advantage in a plant that is in the 50-200 MW size. If there is a market driver, it would go a long way toward insuring the development of this system. After that last meeting involving PG&E and GE, the utilities said they would take the 200 MW combined cycle today instead of the 100 MW ISTIG several years later. There's no institutional barrier; there's just no market. Clint Ashworth agreed. Corman said GE would sell any interested utility an efficient 200 MW system.

Williams concluded that it would be difficult to decide based on this workshop alone, whether this technology needs to be developed more quickly. Whether it needs a push depends on whether there would be broad societal benefits of such an effort that are not captured by market mechanisms. This workshop has shown that ISTIG would offer many benefits -- e.g., low cost, simplicity, short lead time, environmental benefits, flexibility regarding fuel use -- ingredients that suggest the desirability of a development effort. Whether a concerted public policy effort should be made to promote this development should be the agenda for a different forum.

Appendix A

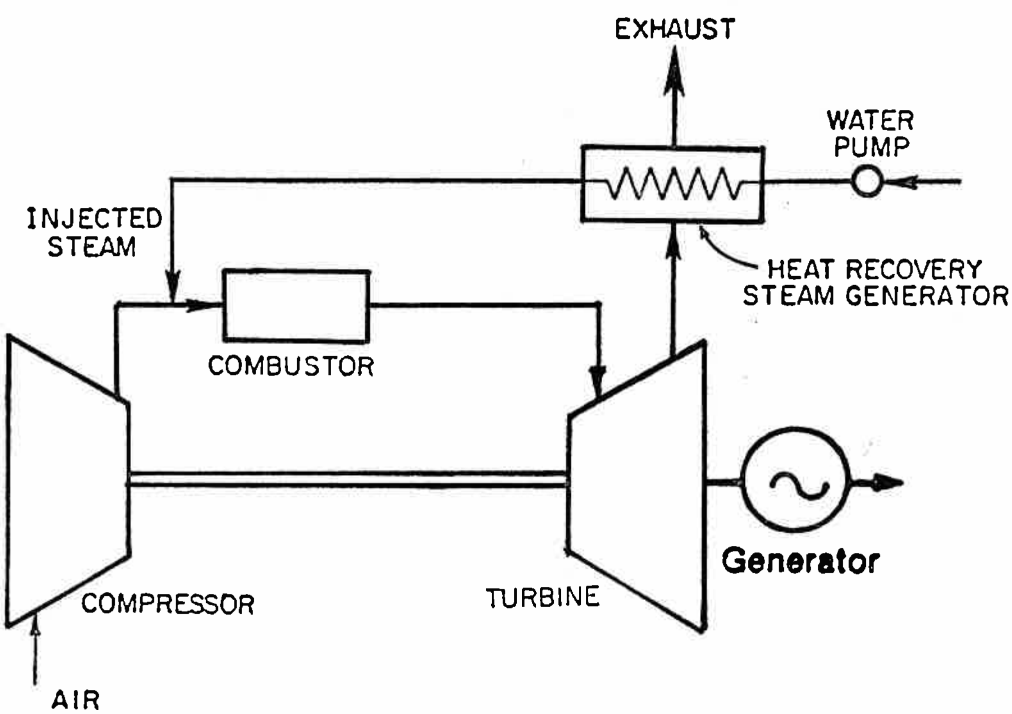
Summary Descriptions of Advanced Gas Turbine Cycle Concepts

A.1. <u>The Steam-Injected Gas Turbine</u>

In a steam-injected gas turbine, an amount of steam equivalent to about 15% of the compressor inlet flow is raised in a turbine-exhaust heat recovery steam generator (HRSG). It is then injected into the combustor of a conventional gas turbine, where it mixes with the compressor outlet air and is raised to the turbine inlet temperature. The additional mass flow through the turbine, together with the higher specific heat of the steam-air mixture, provides additional power output. In addition, the heat transfer from the turbine exhaust is improved in the HRSG, due to the presence of the steam.

Compared to the simple cycle, the only additional work required is that to raise the feedwater to boiler pressure. Thus, cycle efficiency is considerably improved. Because of the increased back-pressure created at the compressor exit due to the injection of steam, however, a machine with a relatively wide surge margin is required. Aircraft-derivative machines are chosen for STIG applications for this reason, and because they are capable of generating power considerably in excess of their rated capacity with only minor hardware modifications.

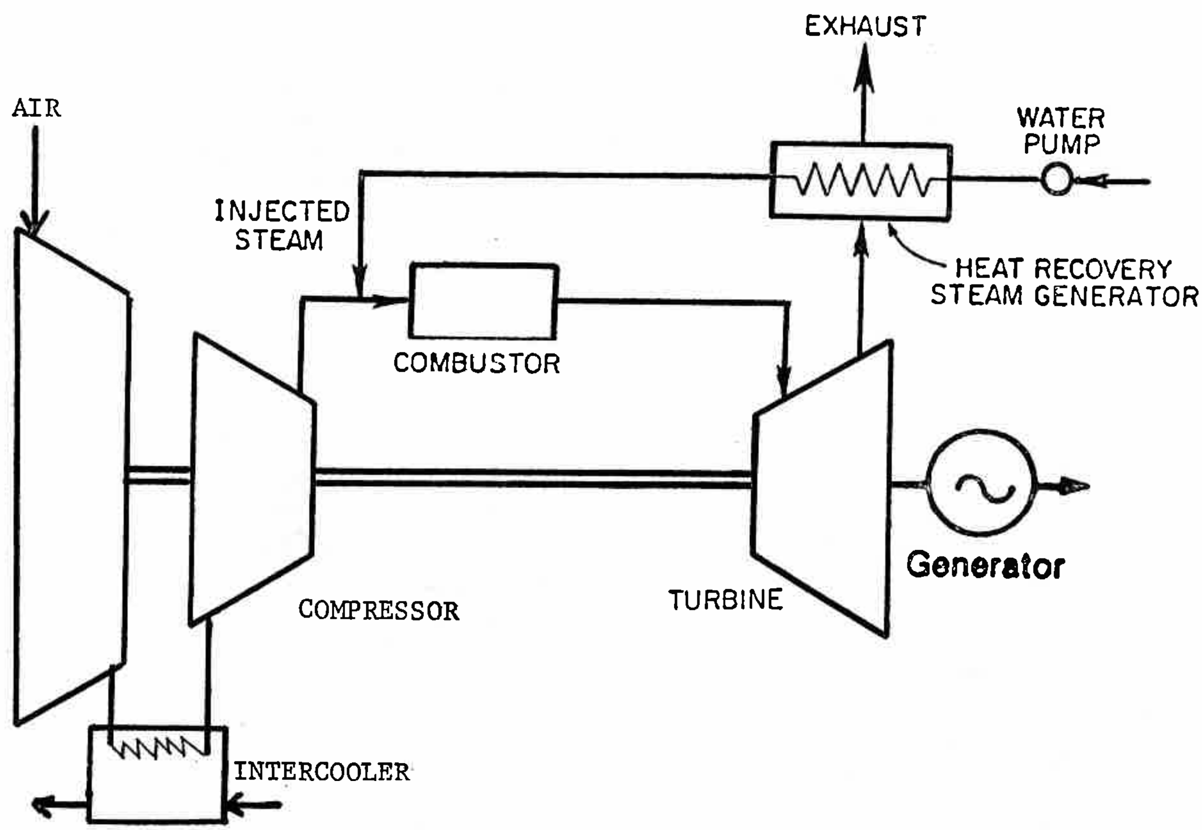
In the Cheng-Cycle (STIG) system, based on the Allison 501-K gas turbine and marketed by International Power Technology, the efficiency is increased from 24% in the simple cycle to 34% with steam injection. The output increases from 3 MW to 5.5 MW. In the STIG system offered by General Electric based on their LM-5000, efficiency increases from 33% to 38% and the output increases from 33 to 47 MW.



A.2. The Intercooled Steam-Injected Gas Turbine

The intercooled steam-injected gas turbine (ISTIG) is a variant of the conventional STIG in which an intercooler is added between compressor stages to reduce the required compressor work and to decrease the temperature of the turbine-blade cooling air bled from the compressor. Since the cooling air is bled at a lower temperature and also contains steam, turbine-blade temperatures can be kept acceptably low while the turbine inlet temperature is raised significantly, leading to more substantial increases in efficiency and power output than in the conventional STIG system.

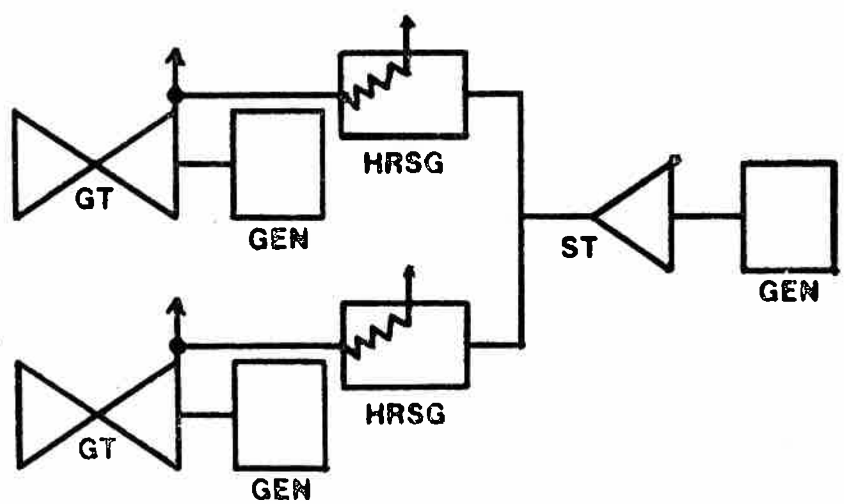
In the ISTIG studied by General Electric, based on their LM-5000 gas turbine, the efficiency would rise from 33% to 47% and the power output would rise from 33 MW to 110 MW.



A.3. The Advanced Combined Cycle

In a combined cycle, the exhaust from one or more gas turbines is used to raise steam in a heat recovery steam generator. The steam drives a condensing steam turbine. Heavy-duty industrial turbines with low compressor pressure ratios are typically used in combined cycles. The characteristically high gas-turbine exhaust temperatures leads to significant steam production.

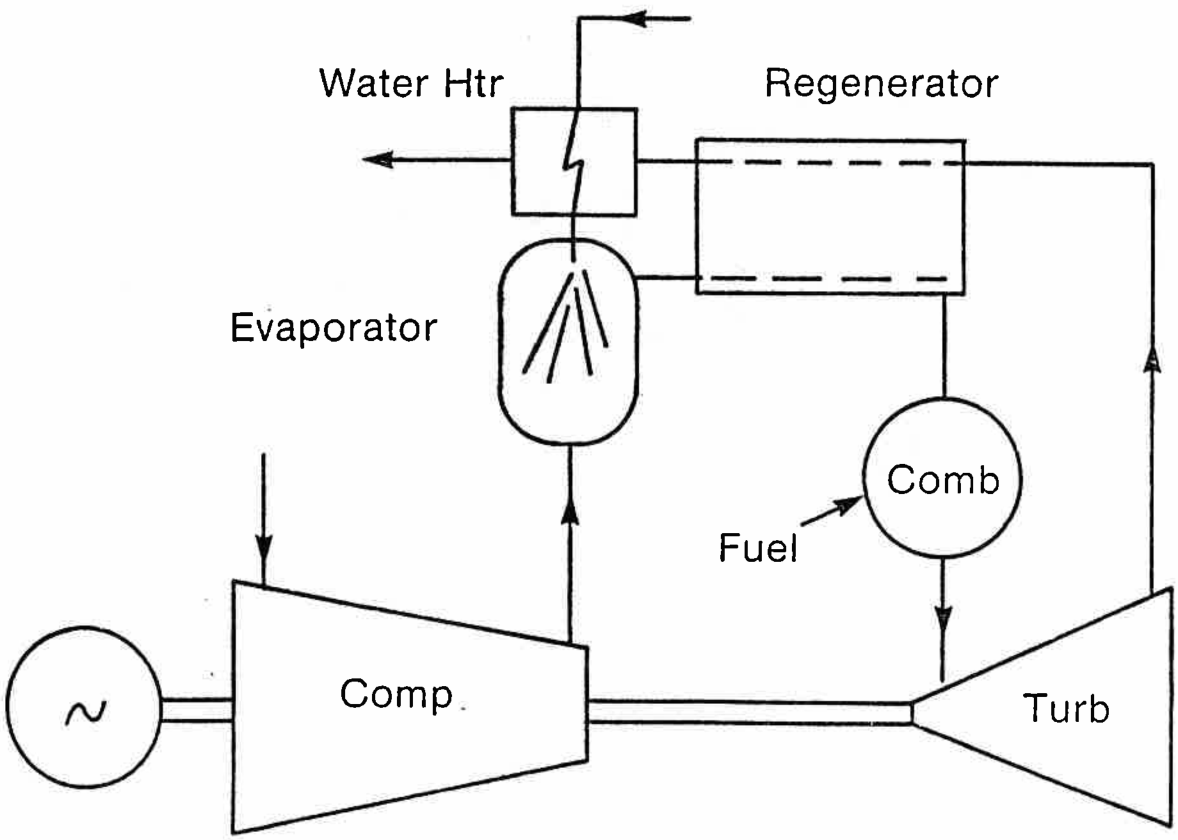
The most efficient combined cycle in use today operates with a gas-turbine inlet temperature of around 2000°F. The Frame 7F Combined Cycle now offered by General Electric, an advanced version of today's combined cycle, operates with a turbine inlet temperature of 2200°F. The higher turbine inlet temperature leads to an increase in efficiency from about 41% in the conventional combined cycle to 45% in the Frame 7F combined cycle. The power output in both cases is about 220 MW.



A.4. The Gas Turbine with Evaporative Regeneration

The gas turbine with evaporative regeneration utilizes the enthalpy of vaporization of water to cool compressor exhaust air, which then passes through a regenerator. The lower temperature of the moisture-laden compressed air gives greater temperature differences in the regenerator, enabling greater heat recovery than in a conventional regenerative cycle. In addition, the presence of some steam on both sides of the regenerator increases the heat transfer rates, leading to still better heat recovery. The amount of moisture evaporated amounts to about 10% of the compressor inlet flow. The added moisture has an impact on power output similar to that in the STIG and ISTIG: the raised turbine flow and higher specific heat lead to greater power output. Since no additional compressor work is required, efficiency increases as well.

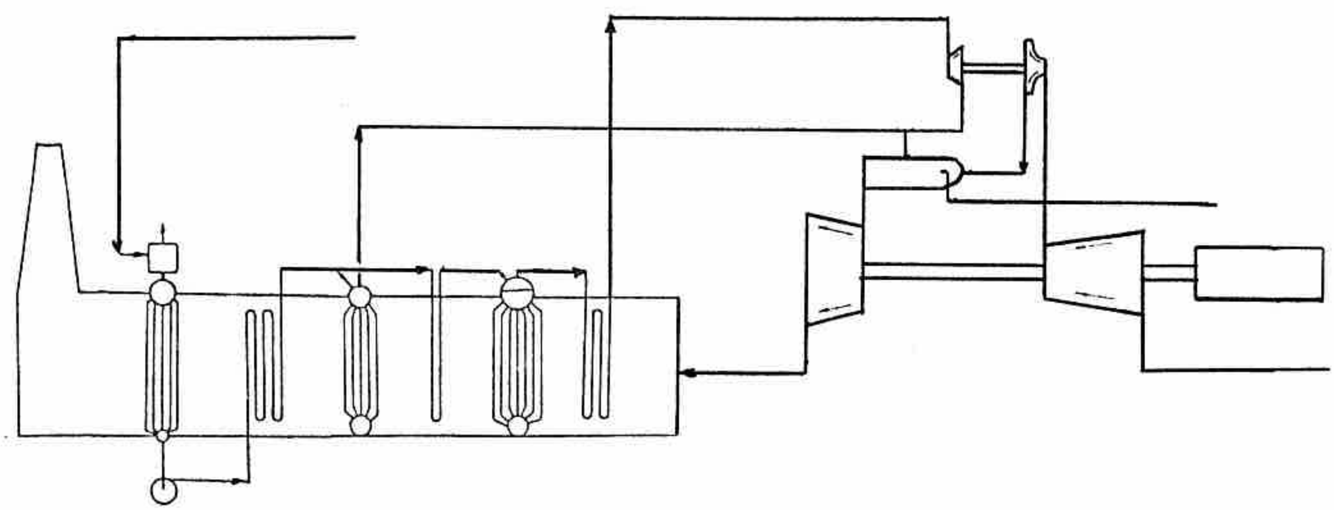
In preliminary evaluations by Westinghouse, a gas turbine with evaporative regeneration based on the W501D5 turbine would produce about 150 MW of power at an efficiency of about 40%. See Appendix C for more details.



A.5. The Turbocharged Steam-Injected Gas Turbine

The turbocharged steam-injected gas turbine (TSTIG) would enable the use of massive steam injection (as used in the STIG and ISTIG) in industrial gas turbines, which generally have surge margins lower than in aircraft-derivative units, and hence are ill-suited for conventional massive steam injection. Steam would be generated at two pressures in a multiple-pressure turbine-exhaust heat recovery steam generator (HRSG). The higher pressure steam would drive a small back-pressure steam turbine, which would drive a turbocharger to provide additional compression of the air exiting the compressor. The steam-turbine exhaust would be injected into the gas-turbine combustor, as would the lower pressure steam from the HRSG. Because of the use of the turbocharger, the injected steam would not increase the back-pressure at the exhaust of the compressor of the original machine.

In preliminary calculations, Richard Foster-Pegg has calculated the efficiency of a TSTIG based on the General Electric Frame 7F industrial gas turbine to be 47.8%, with an output of 153 MW. See Appendix B for details.



Appendix B

The Steam Turbocharged Injected Gas Turbine: Turbo-STIG

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Abstract

A new steam injection gas turbine (STIG) is proposed which allows all the steam raised by recovered heat to be injected into a standard design gas turbine without major modifications. The system improves the cycle efficiency by increasing the overall pressure ratio and by better matching of components with partial injection of steam. The low capital cost common to all STIG systems is retained.

Introduction

Steam is injected into gas turbines at up to two percent of airflow to reduce NO_x and for power augmentation at up to fifteen percent. We are here concerned with steam injection for power augmentation.

The application of the STIG can be for generation of only power when all the steam is injected or it can be for cogeneration, in which case some of the steam is injected and some exported to process.

In all STIG cycles steam is raised in a heat recovery boiler (HRB) and injected into the compressed air of the gas turbine.

Simple STIG (Fig. B.1)

This basic system can be enhanced in a number of ways. The heat recovery boiler can be supplementarily fired to increase the quantity of steam. The arrangement is particularly suited to cogeneration as it allows both the export and the injection steam to be independently varied.

The fuel consumption of a STIG is greater than the same gas turbine operating without steam injection because the steam has to be heated in the combustor in addition to the air. A STIG will raise about 40% more steam by recovered heat than a non-injected turbine because the steam in the exhaust raises other steam.

The injection of steam into a gas turbine between the compressor and the expander increases the flow through the expander and raises the pressure and the pressure ratio required of the compressor. Compressors of production gas turbines are designed for a pressure ratio without steam injection with margin to take care of compressor and expander fouling and transient operations of starting and load increase. Injection of steam in a standard design gas turbine uses some of the design surge margin and makes the engine more tricky to operate and more sensitive to any deposit buildup in the compressor and expander and to compressor deteriation such as foreign object damage or wear by sand ingestion. The expander of a STIG has greater than normal exposure to deposits from impurities in the injected steam.

Maximum efficiency and cost effectiveness of a STIG system is achieved when all the steam raised by heat recovery can be injected into the gas turbine for power enchancement. In a cogeneration plant this allows recovered heat to be converted into power when not needed for export to process as may occur at weekends or at night. If full power and export of steam are required simultaneously the HRB can be supplementally fired.

A gas turbine can be specially built with larger than normal expander flow area to accomodate the injection of all the steam raised by recovered heat. A gas turbine so modified would operate at reduced efficiency when steam was not injected. The market for steam injection gas turbines is not large and the non-standard parts would be a special order and both the parts and the engineering would be costly.

The Recuperated STIG Cycle

For only power generation the incorporation of a recuperator is particularly appropriate as it reduces the recovered steam to a quantity the gas turbine can accept without modifications to the blade path and improves the effectiveness of heat recovery. Fig. B.2 depicts the Recuperated STIG cycle. The steam is injected into the compressed air upstream of the recuperator and is superheated therein.

The Combined STIG Cycle

In a Combined STIG the injection steam is raised by heat recovery at a pressure several times the gas turbine combustor pressure and expanded in a back pressure steam turbine which drives an electric generator before exhausting into the gas turbine combustor (Fig. B.3).

The Turbocharged STIG Cycle The Turbo-STIG

A STIG will raise steam equal to about 15% of its airflow by weight. With the penalty of some loss of surge margin and flexibility a normal gas turbine can accept about half that quantity. The Turbocharged STIG accepts all the steam raised by heat recovery without loss of surge margin and without major modifications of the standard gas turbine.

Like the Combined STIG the injection steam for a turbocharged STIG is raised at a pressure higher than the gas turbine combustor pressure, expanded in a back pressure steam turbine and exhausted into the gas turbine combustor. In the Turbocharged system the steam turbine drives a booster compressor which further compresses the air before it enters the combustor where the steam is injected. The booster compressor accommodates the additional pressure rise resulting from the steam addition. The pressure ratio of the main compressor is not increased and the surge margin is not reduced (Fig. B.4).

The configuration of the gas turbine is that of a recuperated machine, with the recuperator omitted and replaced in the cycle by the turbocharger. Internal modifications required to a recuperated gas turbine to adapt it to a turbocharged system include the injection parts for the steam, changes required to prevent cooling air flowing into the wrong place because the pressure at the inlet to the expander exceeds the pressure at the outlet of the main compressor and strengthening of couplings and shafts because of increased torques.

Because of the higher power of the STIG a more powerful generator will be required and reduction gear if used.

In the turbocharged arrangement the booster compressor may have a pressure ratio of 1.2, raising the potential prressure ratio by 20%. This allows the surge margin and flexibility of the engine to be increased with the injection of all the steam raised by heat recovery.

The pressure ratio for best efficiency of a STIG is higher than for a simple cycle gas turbine and the higher pressure ratio imparted by the booster compressor will always improve the efficiency compared to a simple STIG.

In a simple STIG any additional pressure ratio required for the increased flow through the expander falls on the engine driven compressor, increasing its' absorbed power. In the turbocharged system this work is obtained from the steam before injection. Additionally if the turbocharger produces a greater pressure rise than is required to pass the increased flow the pressure ratio of the main compressor is reduced and the power to drive it.

Like the combined cycle the Turbocharged STIG can benefit from a two pressure boiler. The high pressure steam is expanded in the steam turbine driving the booster compressor and then injected into the combustor. The second pressure level steam is raised at the combustor pressure and is injected directly.

Comparing the performance of combined cycles and Turbo-STIG systems, the heat rates with similar sophistication are almost identical. Power of the STIG can be twice the power of the dry gas turbine. Power of an unfired combined cycle is typically one and a half times the dry gas turbine power. Thus power of the Turbo-STIG is 33% greater than an unfired combined cycle with the same gas turbine. If the combined cycle is supplementary fired to equal the power of the Turbo-STIG, its heat rate is higher than the STIG.

The increased pressure at the inlet to the expander of the STIG passes the increased flow into the expander at the normal velocity. At the exhaust of the expander the pressure is not increased and velocities will be raised. This will increase leaving losses and may cause flow choking or shock waves depending on the design of the turbine.

To minimize such problems it is prudent to select engines for STIG applications which have liberally sized back ends. Failing this choice, a modification to increase the back end area is a less serious modification than opening up the expander all the way through.

These potential problems may be limited in the Turbo-STIG by restricting the airflow of the engine by adjusting compressor inlet guide vanes. Power is reduced by this proceedure but efficiency is almost unaffected and the full flow can be restored if full steam injection is not required. This works for the Turbo-STIG but not for the non-turbo because the reduced guide vane setting reduces surge pressure ratio as well as flow.

Commercially successful gas turbines are without exception products of multiple production. The cost of design and tooling for sophisticated machinery is so high that the cost of one-off production or other than simple modifications to a standard design is prohibitive. Modification of static components for STIG applications may be acceptable but changes to blade path and rotating components must be kept to the minimum to be affordable which the Turbo-STIG does. Other STIG systems require extensive modification of either the compressor or the expander for the full recovered steam production to be accommodated.

The turbocharged system is superior to other STIG systems because of the lesser engine modifications it requires, the higher efficiency resulting from its higher compression ratio and the high efficiency it maintains over the range of steam injection from full steam to zero in cogeneration applications.

Thermodynamic Studies

Canadian Westinghouse 251: Turbocharged STIG cycles based on the CW 251 gas turbine are depicted on material and energy balance diagrams, Fig. B.5 and B.6. The calculations are at 80 F and sea level. Fig. B.5 is at full airflow and Fig. B.6 at 80% airflow. Steam is raised in the heat recovery boiler at 900 psig, 950°F to drive the steam turbine in both cases. Low pressure steam for direct injection is raised at 200 psig at full flow and at 170 psig at 80% flow.

In the full power case shown on Fig. B.5 and listed in the second column of Table B.1, the 900 psig steam expands in the turbine to the combustor pressure of 200 psig producing a mechanical 9,336 kW to drive the booster compressor. The expander inlet pressure is raised by a ratio of 1.17 by the steam injection and the booster compressor operates at a ratio of 1.32 unloading the main compressor to a ratio of 12.17 from a normal ratio of 13.75. The power absorbed by the main compressor is thereby reduced by 3,700 kW.

The fuel input is increased by 43% relative to normal to heat the injected steam from about 600°F to the combustor outlet temperature of 2170°F.

Flow through the expander is increased 21% and expansion ratio from 12.3 to 14.5. Expander power is increased by 46% from 94,759 to 138,383 kW. Gas turbine power is increased from 37,406 to 83,332 kW.

Table B.1. Comparison of performances of CW-251.

	Combined	Turbo-STIG	
Steam injection	yes	yes	yes
Air flow (percent)	100	100	80
Air flow (lbs/sec)	326	326	261
Steam injection (lbs/sec)	---	65.0	65.22
Main compressor ratio	13.75	12.17	10.27
Booster pressure ratio	---	1.32	1.32
Expander inlet (psia)	188	210	175.0
Expander pressure ratio	12.31	14.51	11.49
Fuel input (MBTU/hr, HHV)	487.8	697.3	612.4
Turbo-compressor (kW)	---	9,336	6,993
Main compressor (kW)	56,196	52,475	38,600
Expander (kW)	94,759	138,383	109,788
Net electrical output of GT (kW)	37,406	83,332	69,258
Net electrical output of ST (kW)	21,365	---	---
Total net electrical output (kW)	58,771	83,332	69,258
Heat rate (BTU/kWh, HHV)	8,330	8,368	8,842

A STIG is a form of combined cycle and should be evaluated in this category. The HHV heat rate of the Turbo-STIG is 8,300 BTU/kWh and is approxiamtely equal to the heat rate of the normal combined cycle based on the same gas turbine model with an equally sophisticated cycle. The performance of this combined cycle is listed in the first column of Table B.1.

The performance shown on Fig. B.5 results in an exhaust flow 23% by weight above normal and would require significant design changes. The efficiency benefits may be substantially obtained at a reduced power increment by reducing the compressor airflow with the compressor inlet guide vanes. Operation at 80% compressor flow is depicted on Fig. B.6 and listed in the third column of Table B.1. The power of the Turbo-STIG at 80% airflow is greater than the conventional combined cycle by 18%.

Solar Centaur: A simplified cycle with a single steam pressure is proposed for the Centaur and shown on Fig. B.7.

The expected performance is compared with a simple cycle on Table B.2. The injected steam is 14.3% of the airflow and raises the pressure at the inlet of the expander by about 19%. With a dual pressure boiler more steam could be produced and injected. The steam turbine driven boost compressor unloads the main compressor from a pressure ratio of 10.2 to 9.98 increasing the surge margin.

The net power is increased by 72%, though the expander power is increased only by 32% to about the same power as occurs during cold weather operation.

Table B.2. Comparison of performances of Solar Centaur.

	Simple Cycle	Turbo-STIG
Injection steam (percent of air)	---	---
Air flow (lbs/sec)	38.58	38.58
Main compressor ratio	10.2	9.98
Main compressor (kW)	5,783	5,706
Turbo-compressor Ratio	---	1.19
Turob-compressor (kW)	---	780
Expander flow (lb/sec)	39.32	45.02
Expander inlet (psia)	142.5	169
Expander pressure ratio	9.43	11.10
Expander exhaust (^{o}F)	954	937
Expander kW	9,412	12,381
Net electrical output (kW)	3,763	6,475
Natural gas input (MBTU/hr, LHV)	47.37	58.43
Natural gas heat rate (BTU/kWh, LHV)	12,590	9,032
Natural gas heat Rate (BTU/kWh, HHV)	13,849	10,026

The booster turbo-compressor transmits 780 KW. A non-return valved bypass of the compressor allows normal operation when the steam is required for other use. The net heat rate is calculated to be 9,200 BTU/kWh LHV, 10,120 HHV on natural gas.

Indirect Heated Canadian Westinghouse 191: An indirect heated gas turbine can operate on a variety of solid and waste fuels. The configuration is readily adaptable to STIG operation. The result is a power plant able to burn very low cost fuel with excellent performance for cogeneration or power production. The performance of a plant based on the CW 191 with a circulating fluid bed combustor is shown on Fig. B.8. The power is increased from 16,000 kW of the normal CW 191 engine to 34,000 kW of the Turbo-STIG.

The heat required to superheat the injected steam in the air heater increases the fuel input from 312 million BTU per hour operating on all air to 411 million BTU for the Turbo-STIG.

General Electric Frame 7: A comprehensive evaluation of several STIG cycles is documented in an EPRI report [B.1]. The study was by General Electric and is based on the Frame 7 gas turbine design. Simple and combined cycles were compared with three STIG systems which did not include the Turbocharged arrangement. The STIG systems calculated by GE and included in the report are the simple system shown on Fig. B.1, the recuperated system (Fig. B.2) and a Combined STIG depicted on Fig. B.3. The Recuperated STIG was judged least promising, was omitted from the economic comparisons, and is not considered further here.

The conclusion of the EPRI study is that the Combined STIG is the more cost effective of the three STIGs studied, none of which showed sufficient improvement over the already developed STAG combined cycle to warrant the STIGs' development.

PERFORMANCE OF THE TURBO-STIG: The performance of the Turbo-STIG Frame 7 shown on Fig. B.9 is based on the normal pressure ratio of 16. The booster compressor raises the overall ratio to 20 which is about the thermodynamic optimum for a STIG with a firing temperature of 2200°F.

The compression ratios of other gas turbines considered for conversion to Turbo-STIG herein are all less than the normal Frame 7. At the higher pressure ratio of the Frame 7, the production of recovered steam is relatively less as is the power of the steam turbine. For these reasons the booster ratio is less and the main compressor is not unloaded and operates at a ratio of 16. Power output is augmented by a factor of 1.9, not as much as with lower pressure engines.

The power of the Turbo-STIG gas turbine is 154.7 MW. Auxiliaries and losses consume 2 MW for a net of 152.7 MW. THe heat rate is calculated to be 7150 BTU/kWh. The high pressure results in outstanding efficiency of 47.8% and very reasonable water consumption.

The efficiency calculated for the Turbo-STIG Frame 7 is substantially better than the STAG combined cycle in the EPRI report. It is about equal to efficiencies quoted for advanced combined cycles in recent EPRI reports.

All calculations of the Turbo-STIG Frame 7 are by the author and have not been reviewed by General Electric.

Performance of the Turbo-STIG is compared with the leading systems in the EPRI report in Table B.3.

Power outputs of the Combined and Turbo STIG cycles are almost identical at 1.9 times the simple cycle. Heat rate of the Turbo-STIG is substantially better than either the Combined STIG of the STAG plant of the EPRI report. Water consumption of the Turbo-STIG approaches the STAG plant and is considerably lower than the Combined STIG.

ECONOMICS: The capital costs of a Turbo-STIG are estimated based on the criteria and capital costs of the EPRI study.

The EPRI study is in 1974 dollars and costs therein, other than fuel, are updated to 1986 by an inflation of 5.9% per year, equal to a factor of 2 overall. In the EPRI study fuel is assumed to cost $3/MBTU. Considering recent trends, inflation is not applied to fuel costs, and the same $3/MBTU is used here.

Readers comparing costs herein with costs in [B.1] please note that costs herein, other than those relating to fuel, are twice the comparable costs in the reference because of inflation.

This inflation factor results in a somewhat high cost for the Simple Cycle gas turbine of $292/kW compared to the EPRI guide of $230 for an

Table B.3. Cycles modelled on General Electric Frame 7 Gas Turbine

PERFORMANCE	Simple Cycle	Combined STIG	Turbo STIG	Combined Cycle
Number of Gas Turbine	1	1	1	4
Overall Compression Ratio	16	12	19.2	16
Steam Injected (lb/sec)	--	105.5	85.5	--
Steam Pressure (psig)	--	1450	1500	1450
Steam Temperature (°F)	--	1000	900	1000
Steam Turbine Power (MW)	--	20	12	146
Gas Turbine Power (MW)	82	134	154.7	347
Auxiliary Power Used (MW)	1.4	1.8	2.0	17
Net Station Generation (MW)	80.6	152.2	152.7	476
Fuel (MBTU/hr)	848.8	1,270	1,091	3,821
Heat Rate (BTU/kWh)	10,531	8,342	7,150	8,028
Efficiency (percent, HHV)	32.4	40.9	47.8	42.5
Water Consumption (gal/kWh)	--	0.30	0.25	0.21
Years to Construct	1	1	1	2
COSTS (millions of dollars)				
Gas Turbine Generator	17.6	19.8	20.0	65.6
Heat Recovery Boiler	--	10	10	40
Steam Turbine Generator	--	6.2	--	32
Steam Turbine Compressor	--	--	4.0	--
Water Treatment	--	2.2	2.0	--
Condenser Cooling Tower	--	--	--	11
Sub-total, Installed Cost	17.6	38.2	36.0	148.6
Contingency, Escalation, AFDC	5.98	13.0	12.24	50.5
Total Capital Cost	23.58	51.2	48.24	214.8
Total Specific Cost ($/kW)	292.56	336.4	315.9	451.3

advanced gas turbine ordered in 1986. For the STAG plant the cost agrees well at $451 versus $455/kW.

COSTS OF THE GAS TURBINE: The cost of the changes to convert the simple cycle gas turbine to a Combined STIG gas turbine when adjusted to 1986 is $2.2 million. This includes a larger generator and expander with flow area increased to accommodate the steam and also drop the pressure ratio to 12.

The Turbo-STIG requires an increase in expander area only in the last stage, compared to an increase from first to last stage in the Combined STIG, and a generator increased in capacity by 73 MW, compared to the lesser increase for the Combined STIG in [B.1] of 52 MW. It is judged that the plus and minus differences almost balance and the Turbo-STIG gas turbine installed costs is made \$20 million versus the 19.8 million of the Combined STIG.

COSTS OF HEAT RECOVERY AND BOILER INSTALLATION: The HRB in the Turbo-STIG produces 19% less steam than the boiler of the Combined STIG at 100°F lower steam temperature. On the other hand it has an extra pressure level. These differences are assumed to cancel each other and the cost of both is made equal at \$10 million.

STEAM TURBO COMPRESSOR COSTS: The steam turbo generator in the Combined STIG generates 20 MW and costs \$6.2 million including installation.

The turbine compressor in the Turbo-STIG transmits 12 MW. It is lower power than the turbine generator with about the same steam conditions. The turbine compressor is a smaller, direct coupled, high speed unit. It is entered at a cost of \$4.0 million.

COSTS OF WATER TREATMENT SYSTEMS INSTALLED: The Turbo-STIG uses 19% less water than the Combined STIG and the cost is reduced by 10% from the cost for the Combined STIG in the EPRI study.

TOTAL INSTALLED COSTS: The total of the above installed cost for the Turbo-STIG is \$36 million compared to the \$38.2 million of the Combined STIG.

Contingency, escalation and AFDC for the Turbo come to \$12.24 million, using the same percent markup as the EPRI study, for a total capital cost of \$48.24 million, compared to \$51.2 million for the Combined STIG. The reduction is principally due to the lower cost of the steam turbo compressor compared to the steam turbo generator.

Specific cost of the Combined STIG is \$336.4/kW, of the Turo-STIG \$315.9/kW, and of the STAG \$451.3/kW.

COST OF ELECTRICITY: Cost of treated water is taken to be the escalated value in the EPRI study for the Combined STIG and the STAG. For the Turbo the cost is reduced by 19%. Cost of maintenance is assumed the same for all systems at 4.0 mills/kWh after inflation.

In the EPRI study fuel is assumed to costs \$3/MBTU. Considering recent trends in fuel costs inflation is not applied and the same \$3.0/MBTU is used here.

Annual fixed charges are 18% of the total capital cost.

The cost of electricity of the Combined and Turbo-STIG and the STAG cycles are compared in Table B.4. The Turbo-STIG is significantly more economical than either of the other systems. For example, at 65% capacity factor the power cost of the Turbo-STIG is 32.44 mills/kWh, the Combined STIG is 36.43 mills/kWh, and the STAG is 37.48 mills/kWh. Where the Combined STIG of the EPRI study showed minor improvement relative to the

Table B.4. Electricity Cost Comparison of Cycles Modelled on the General Electric Frame 7 Gas Turbine.

CAPITAL	Combined Cycle	Turbo-STIG	STAG
Installed Cost ($/kW)	336.4	315.9	451.4
Fixed Charges ($/kW/year)	60.55	56.86	81.25
VARIABLE COSTS (Mills/kWh)			
Water and Treatment	0.6	0.5	0.12
Maintenance	2.0	2.0	2.0
Fuel	25.27	21.45	24.08
Total Variable	29.52	25.95	28.20
COST OF ELECTRICITY (Mills/kWh)			
Fixed Cost for Cap. Factor = 1	6.9	6.49	9.28
Total Cost, Cap. Factor = 1	36.43	32.44	37.48
= 0.65	40.15	35.93	42.48
= 0.50	43.32	39.93	46.76
= 0.10	98.64	90.85	121.00

STAG, the Turbo-STIG introduced herein exhibits substantial improvement. In a cogeneration role its superiority is greater because of the higher efficiency at reduced rates of steam injection because of better matching. Considering the smaller redesign and retooling required, the Turbo-STIG strongly merits in-depth investigation which this report does not pretend to offer.

References

[B.1] Steam-Injected Gas Turbine Study: An Economic and Thermodynamic Appraisal, AF-1186, study by General Electric for the Electric Power Research Institute, principal investigator D.H. Brown, Sept. 1979.

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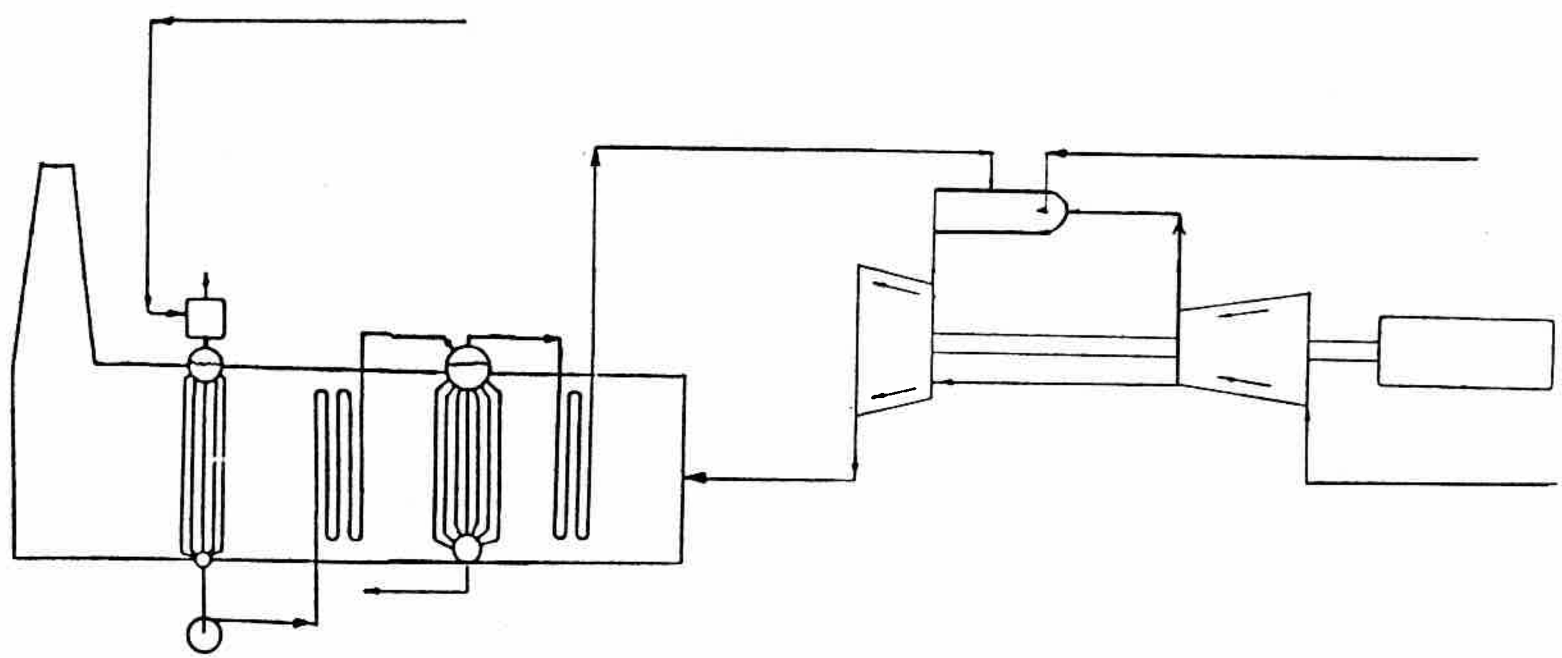

Fig. B.1. Simple Cycle

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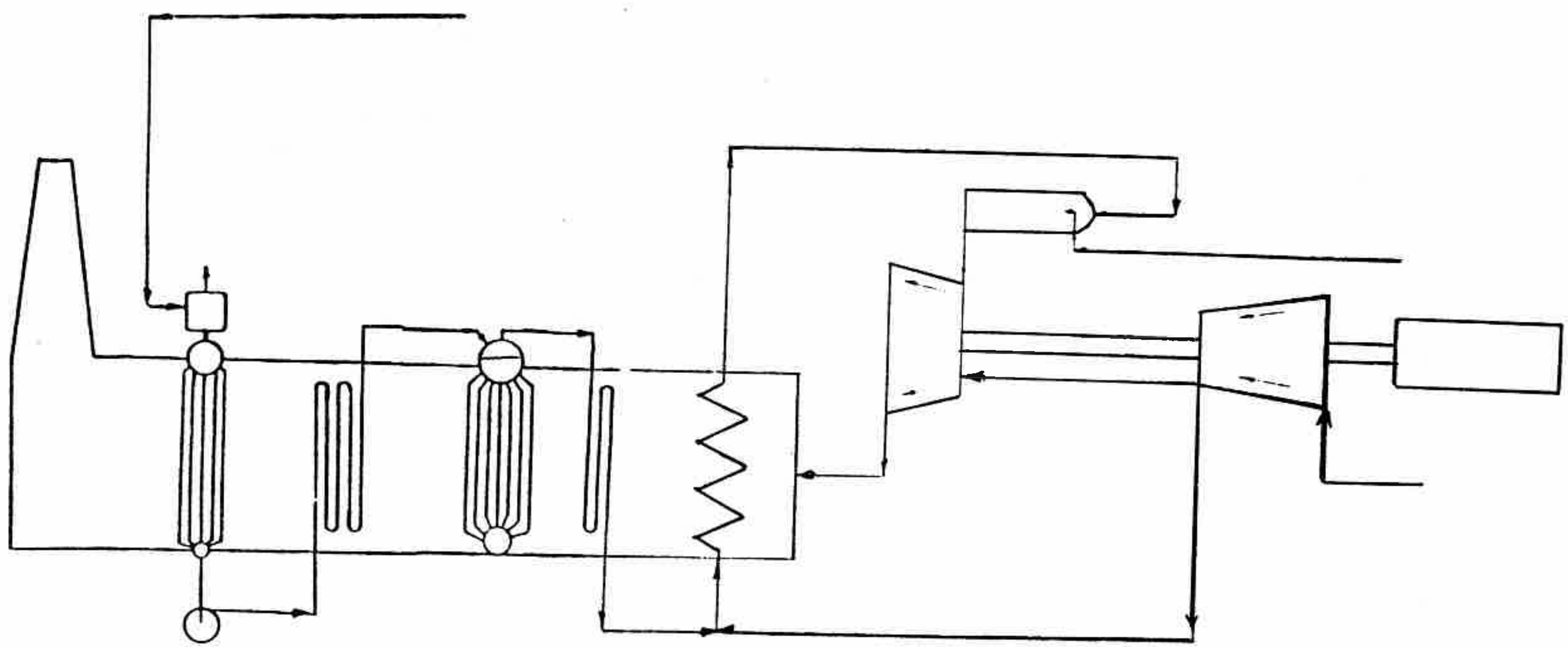

Fig. B. 2. Recuperated Cycle

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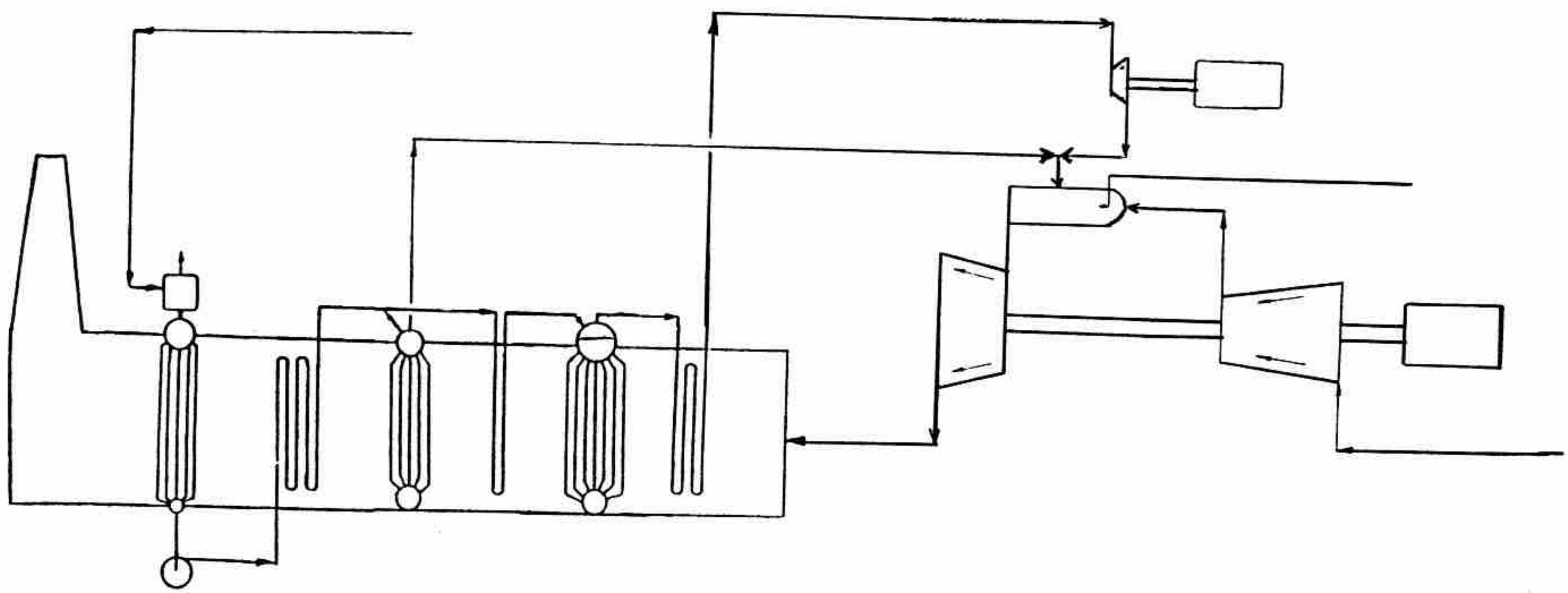

Fig. B. 3. Combined Cycle

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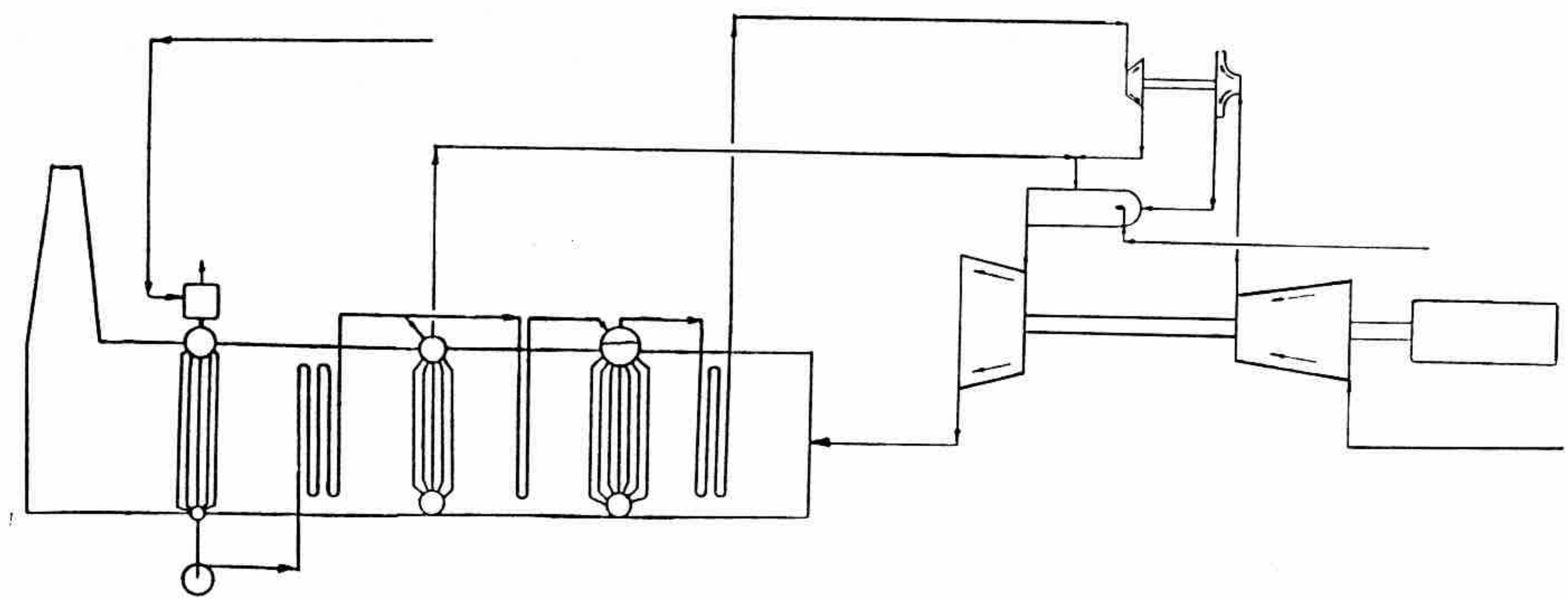

Fig. B. 4. Turbocharged Cycle

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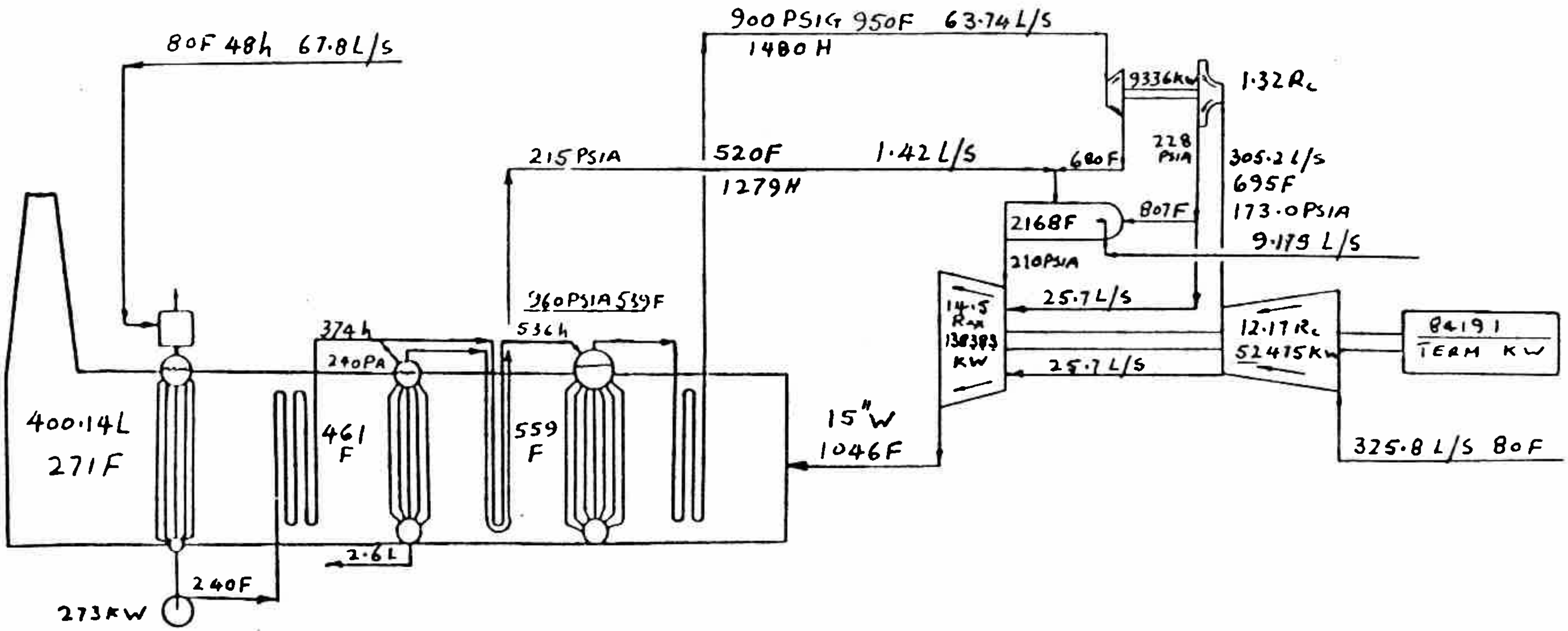

Fig. B. 5. Canadian Westinghouse 251 100% Air Flow

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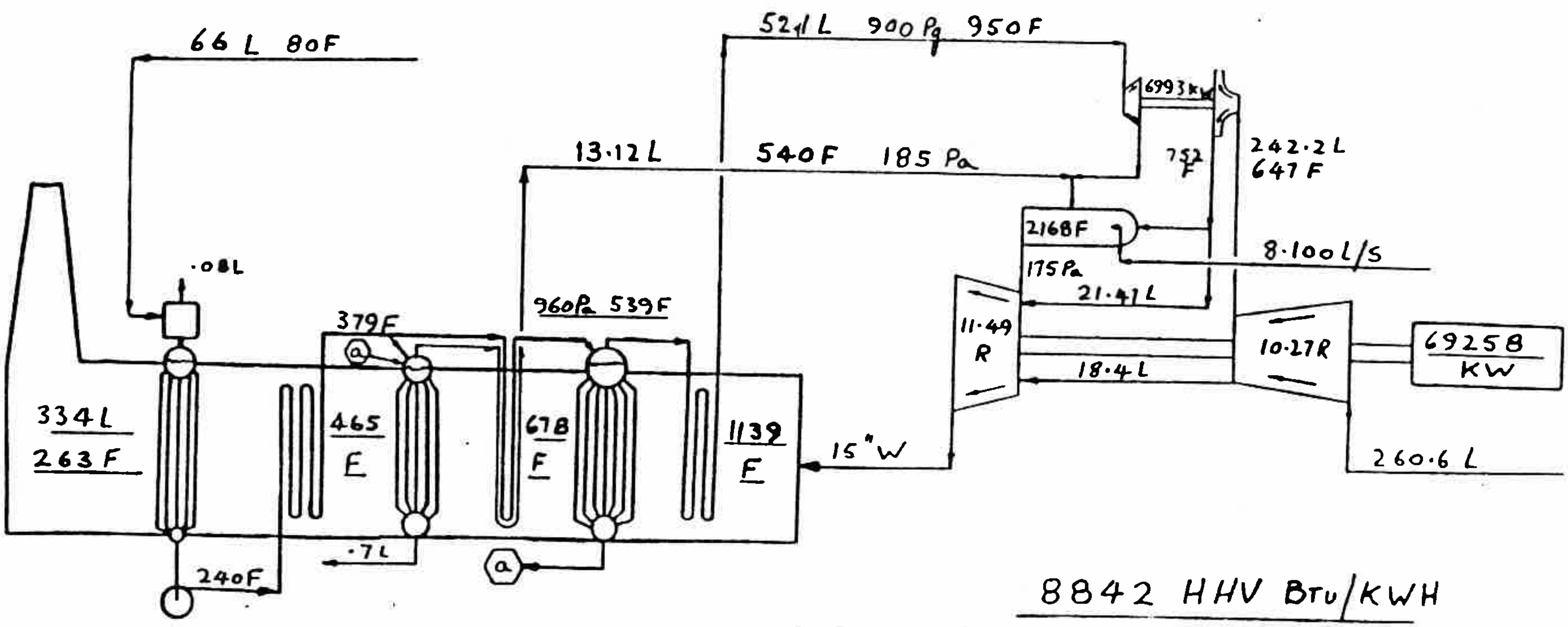

Fig. B. 6. Canadian Westinghouse 251 80% Air Flow

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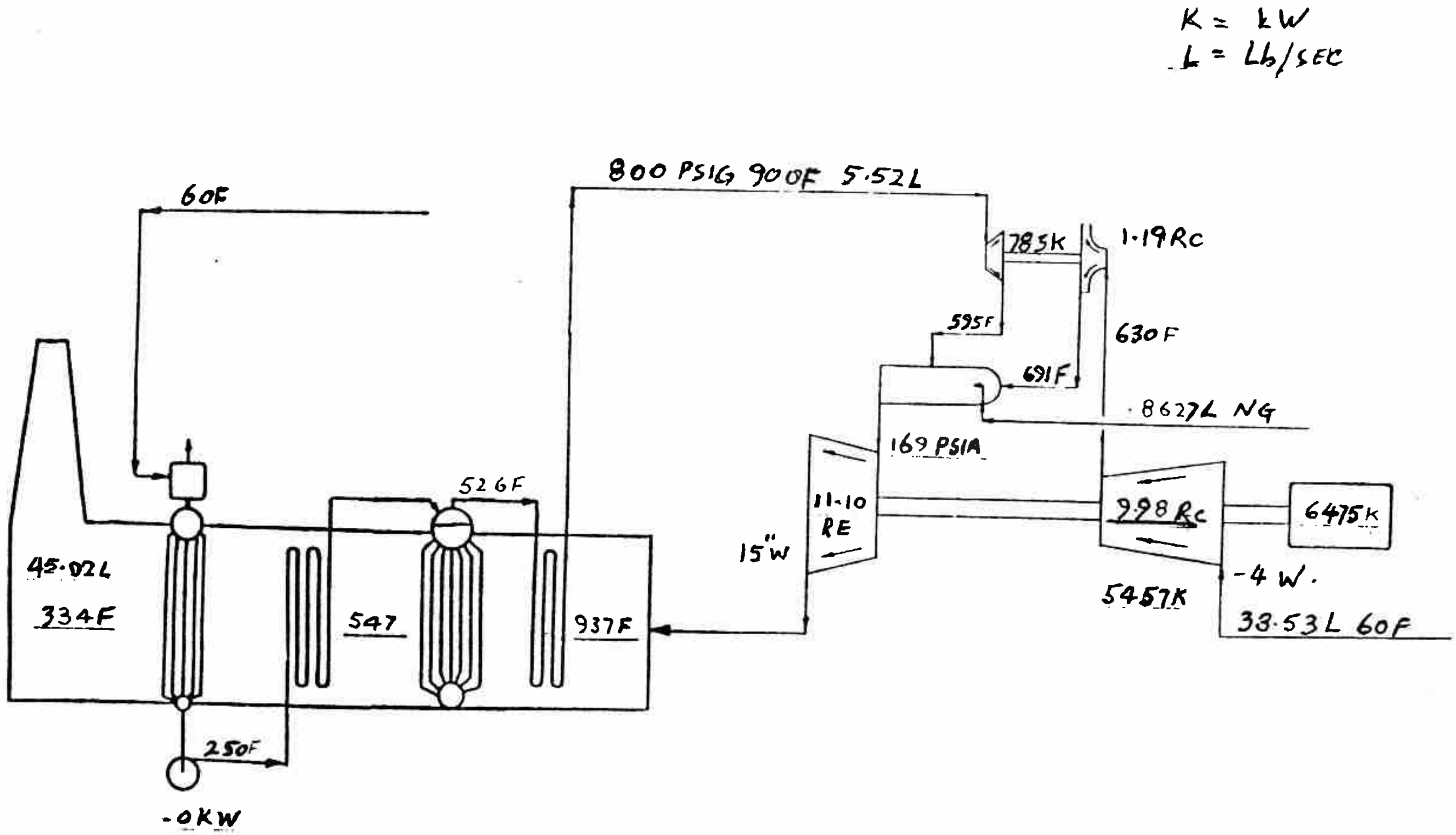

Fig. B. 7. Solar Centaur Turbo-Stig Cycle

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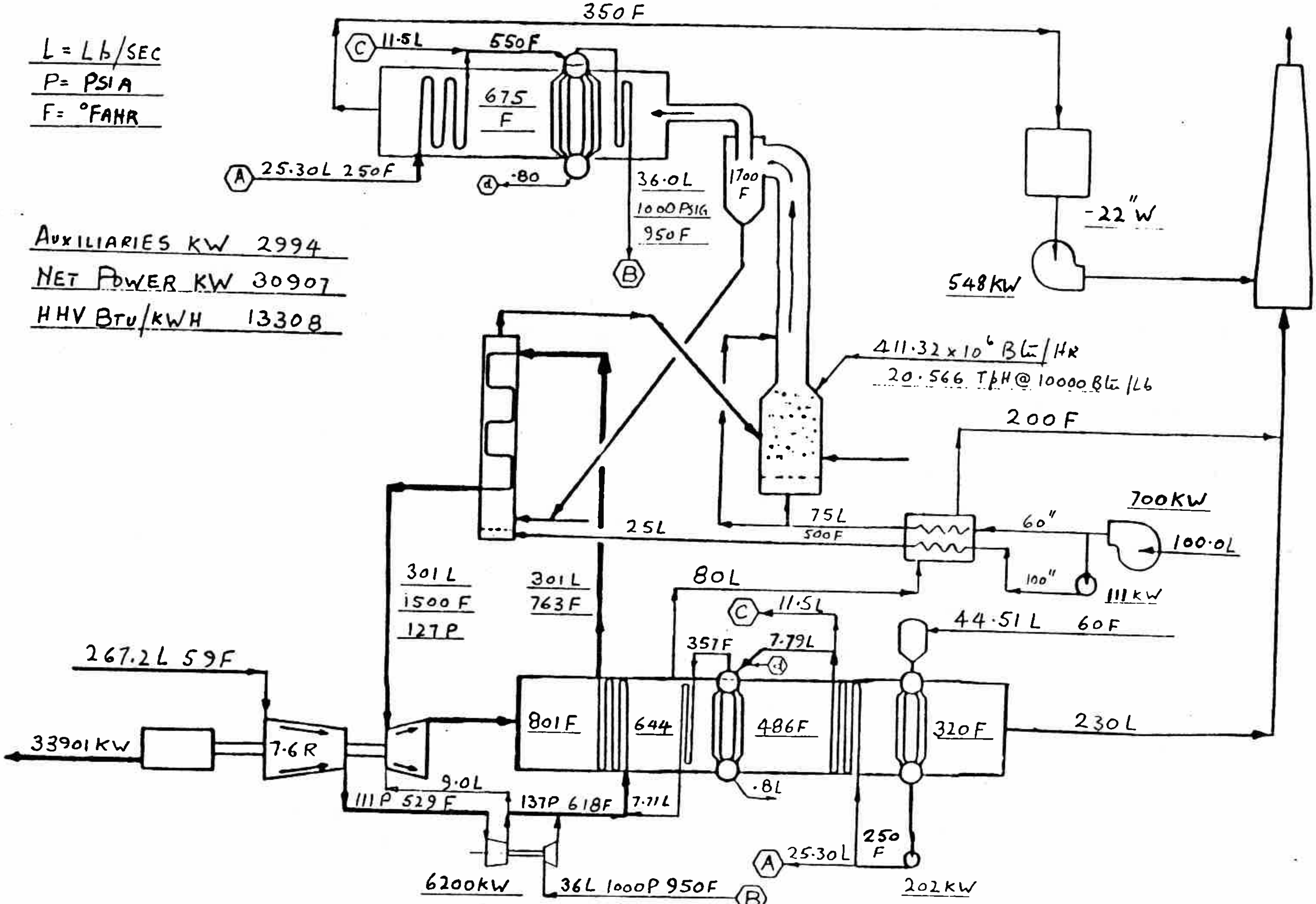

Fig. B. 8. Canadian Westinghouse 191 Indirect Heated Turbo-Stig

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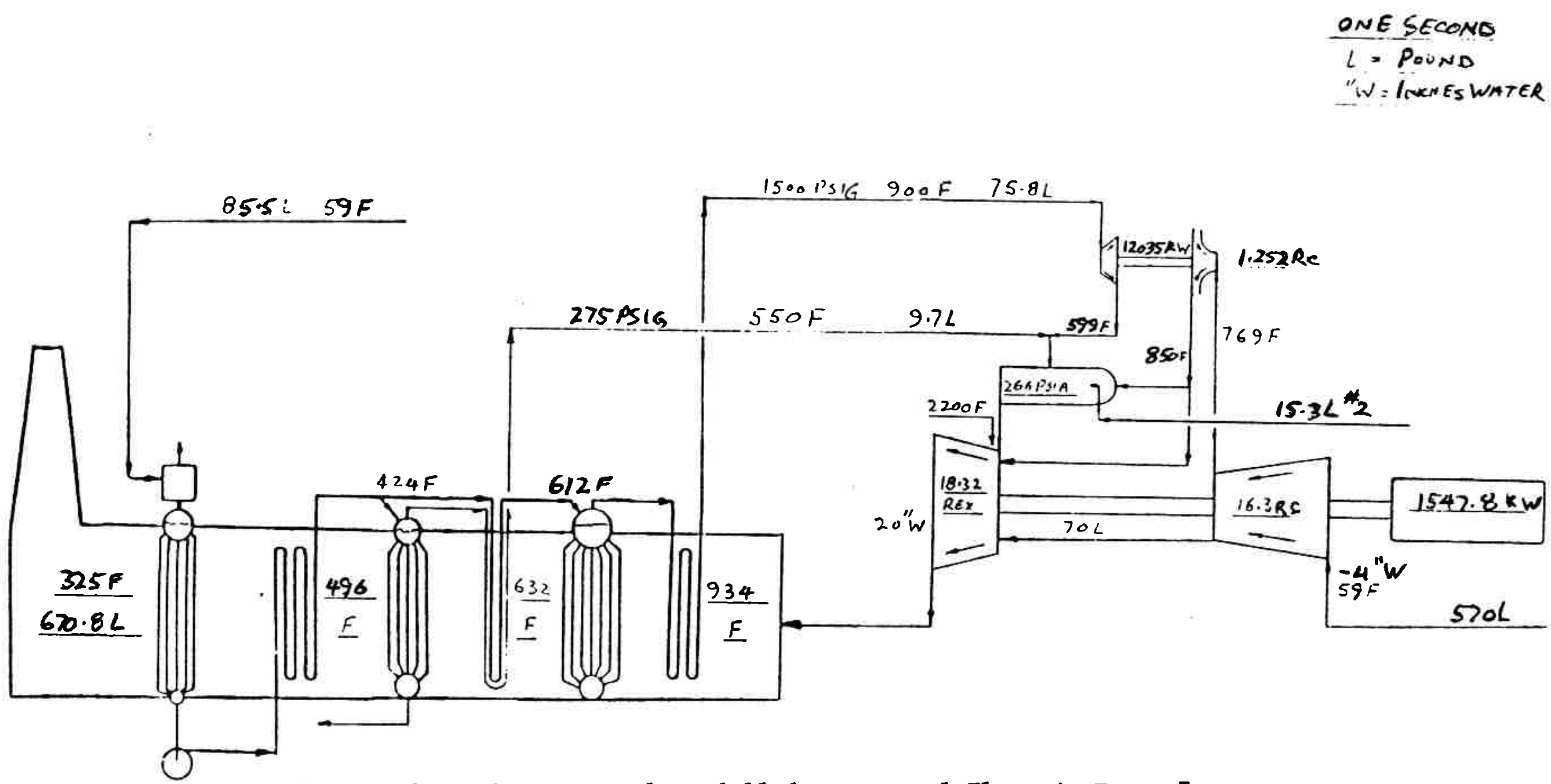


Fig. B. 9. Turbo-Stig Cycle Modelled on General Electric Frame 7

Appendix C

The Evaporative-Regenerative Gas Turbine

Richard V. Garland

Power Generation Group
Westinghouse Electric Corporation
Concordville, Pennsylvania

Introduction

If one were to list the many advantages and attributes that the gas turbine offers as a prime mover, the following items would be included:

1. Short construction period
2. Adaptable to a variety of fuels
3. Very high power density (small plant foot print)
4. Quick starting
5. Low emissions, expecially CO and UHC
6. High specific power, kW/lb/sec air flow

The gas turbine has been applied in three basic forms: (1) the simple cycle, which has been used mainly in peaking application; (2) the combined cycle, which has been used for efficient, baseload application; and (3) the regenerative cycle, which resembles the simple cycle but is more efficient.

Low capital cost is the driving force behind the design of a simple cycle peaking machine. It is, therefore, incumbent upon the turbine designers to produce a machine that delivers the highest power output per pound of air flow. In that way the size and cost of the equipment are minimized.

Combined cycle are designed for high efficiency. Cycle analysis shows that high gas turbine output per pound of air flow applied to combined cycles provides for the highest combined cycle efficiency. Thus, the same basic gas turbine design can be used in both peaking and combined cycle applications and tends to be a design with high pressure ratio.

Regenerative machines, on the other hand, are more practical operating on low pressure ratio. With low pressure ratio, the difference between the compressor discharge temperature and the turbine exhaust temperature is high and the transfer of heat in the regenerator is accomplished readily. Increasing the pressure ratio and applying state-of-the-art turbine inlet temperatures decreases that temperature difference.

In fact, there is a pressure ratio limit beyond which the regenerative gas turbine cycle becomes impractical and, eventually, impossible. Table C.1 is a tabulation of compressor discharge conditions and expander exhaust conditions based on representative compressor and expander efficiencies, and representative combustor exit temperatures with varying pressure ratios. It is seen in the table that regeneration is very desirable at low pressure ratios and becomes less advantageous as pressure ratio increases. In fact, at 24 to 1 pressure ratio, applying regeneration would lower the compressor discharge temperature. It is marginally practical at 12 to 1 because adding a large heat exchanger to gain a hundred degrees or so in combustor inlet air temperature is not an economical option.

To make regeneration effective at high pressure ratios, compressor intercooling is necessary to reduce compressor discharge temperature; but, intercooling complicates the machinery arrangement. There is another option available, however.

Table C.1. The feasibility and practicality of regenerative gas turbines: Typical compressor discharge and expander exhaust conditions based on representative combustor outlet temperatures.

Compressor Pressure Ratio	Compressor Discharge T (°F)	Expander Exhaust T (°F)	Temperature Difference
4	356	773	+ 417
8	537	990	+ 453
12	645	975	+ 330
16	743	964	+ 221
20	825	902	+ 77
24	896	854	- 42

Evaporative-Regenerative Cycle

Evaporative cooling has been used in gas turbines for many years. The common application involves placing a spray evaporator at the gas turbine compressor inlet. Output and efficiency are enhanced because the turbine is able to operate at higher pressure ratio commensurate with the cooled compressor inlet air.

In the evaporative-regenerative cycle the effect of evaporative cooling is applied at the compressor discharge instead of the inlet. By spraying water inot the compressor discharge stream, temperature will be reduced, mass flow will be increased without additional work of compression, regeneration can be employed, and pressure ratios can be increased. The cooling of the compressor discharge air permits the use of high pressure ratios and their inherent advantages. In effect, one basic turbine design can be used for peaking, combined cycle, and regenerative applications.

Initial calculations of the evaporative-regnerative gas turbine cycle show overall thermal efficiencies well over 40 percent are possible. Considering the fact that a modern oil-fired reheat steam power plant can barely achieve this level of efficiency; and, considering that complexity, size, and manpower requirement of a steam plant, the evaporative-regenerative cycle demands investigation.

Cycle Description and Performance: As shown in Fig. C.1, the compressor discharge air is spray-cooled before it enters the regenerator. The turbine exhaust gases give up sensible heat to the moisture-laden compressor air and to the water being piped to the spray evaporator. Figures C.2 and C.3 show two examples, one at 2122°F burner outlet temperature (BOT) and one at 2190°F BOT. It is interesting to note the refrigeration effect of spray evaporation. In Fig. C.2 the 720°F compressor air and 358°F water combine to yield a 335°F exit stream. In Fig. C.3, 702°F air and 354°F water combine and result in a 272°F exit stream. The final mix temperature is a function of evaporator effectiveness.

Output and heat rate are also listed on the figures. The W501D5 is nominally rated at 100 MW with a LHV heat rate of 10,500 BTU/kWh at 2112°F BOT. Using spray intercooling and regeneration improves those figures to about 150 MW and 7700 BTU/kWh (LHV). Figure C.4 is an interesting comparison of heat rate, output per pound of air flow, and pounds of water consumed per kW produced. The evaporative-regenerative cycle consumes less water than either the steam-injected cycle or the combined cycle.

The Effect of Evaporator Effectiveness: It was mentioned earlier that the final mix temperature out of the spray-evaporator is a function of effectiveness. High values yield low mix temperatures and vice-versa. Figure C.5 shows how cooler effectiveness affects performance. With no spray cooling effect the output is analogous to a regenerative machine with a very large regenerator. At the other extreme, 100% effectiveness shows output about 40 percent greater with more than 6 points improvement in thermal efficiency. Spray cooler effectiveness of 30 percent or so seems to yield excellent performance without making either the regenerator or the evaporator system too large.

G-W EVAP-REG CYCLE

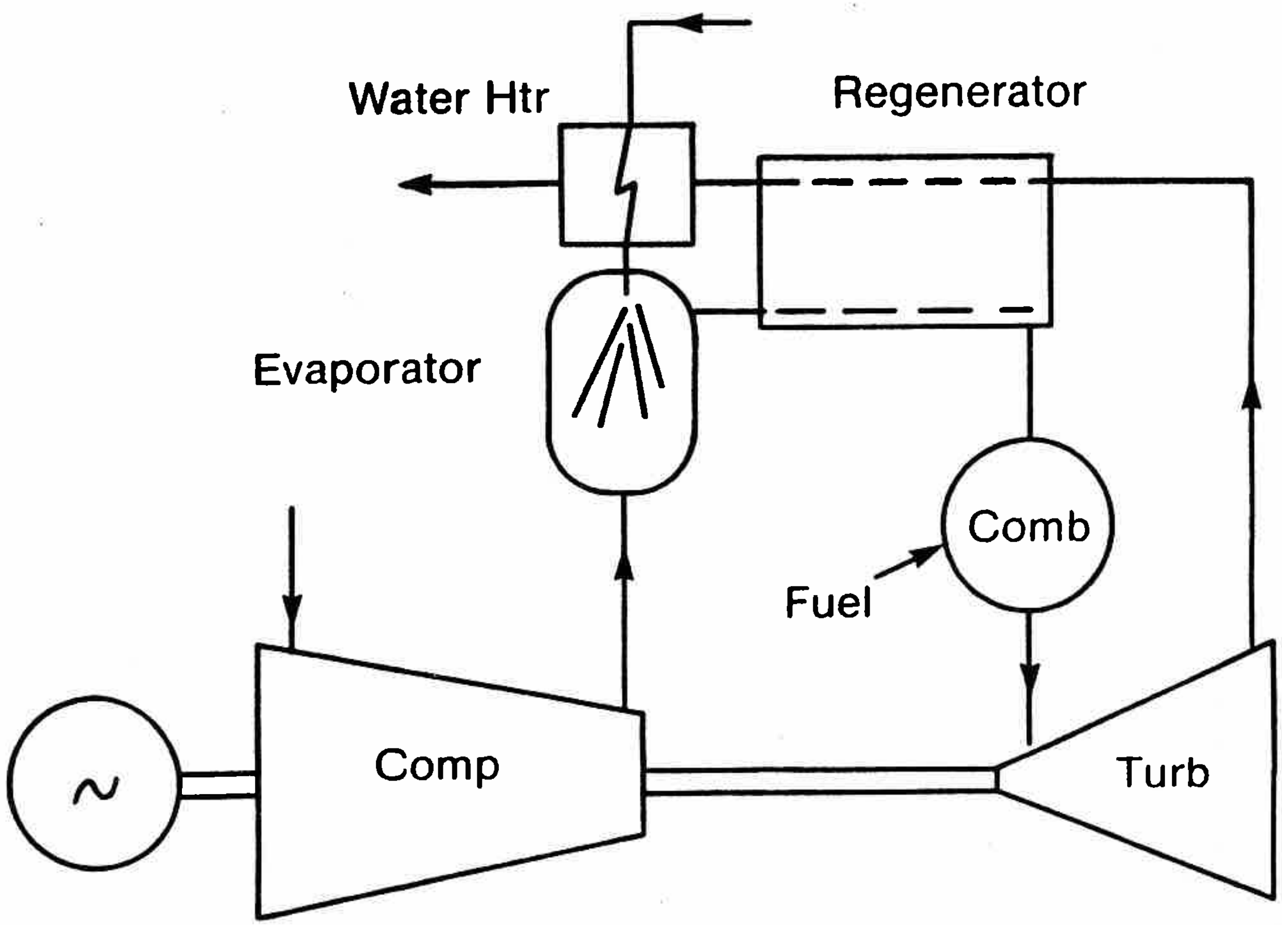
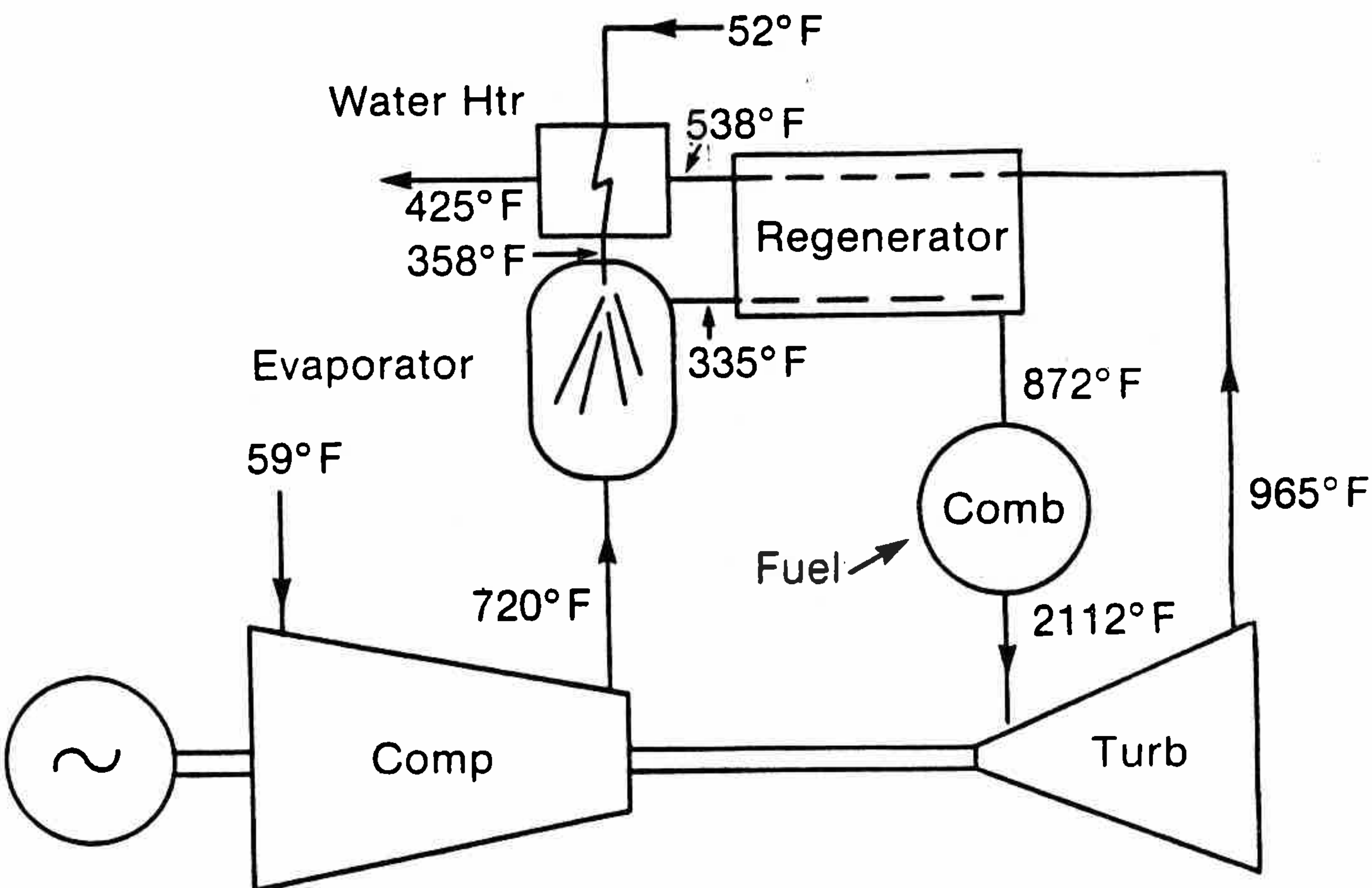


Fig. C.1

W501D5 GENERATOR LIMITED PERFORMANCE G-W EVAP-REG CYCLE

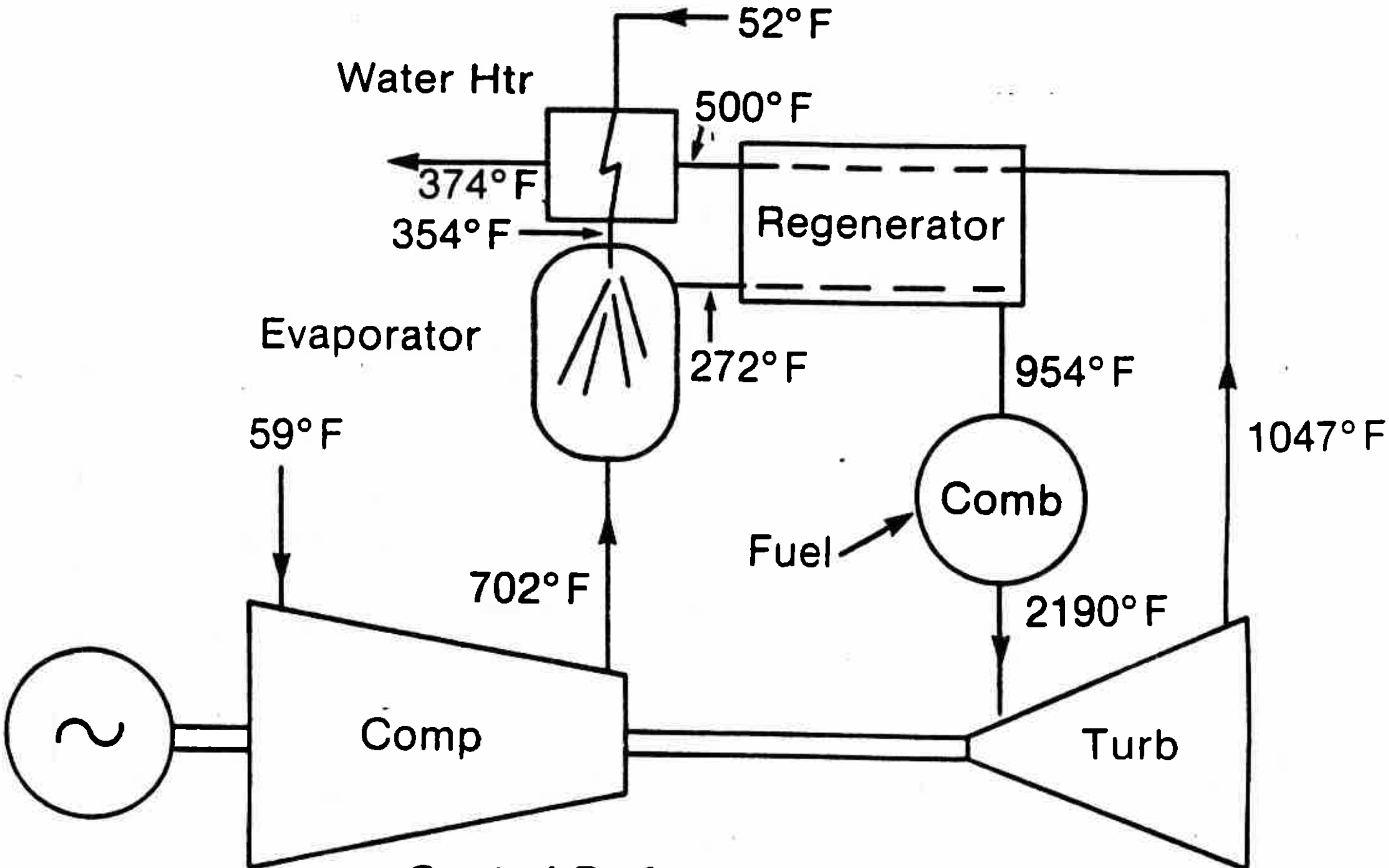


Quoted Performance (Gas)

Power - 130 MW
HR - 9000 Btu/KW-HR (HHV)
HR - 8083 Btu/KW-HR (LHV)

Fig. C.2

FULL CAPABILITY W501D5
G-W EVAP-REG CYCLE



Quoted Performance (Gas)

Power - 149.5 MW
HR - 8578 Btu/KW-HR (HHV)
HR - 7732 Btu/KW-HR (LHV)

Fig. C.3

PERFORMANCE COMPARISON

(Nominal Not Guaranteed)

	Simple Cycle	Steam Injected	Evap. Regen.	Combined Cycle
Heat Rate (LHV)	9220	7790	7580	7365
Kw/Air Flow	118	148	191	188
Lb/Hr/Kw	0	2.59	2.08	2.69-4.60

Fig. C.4

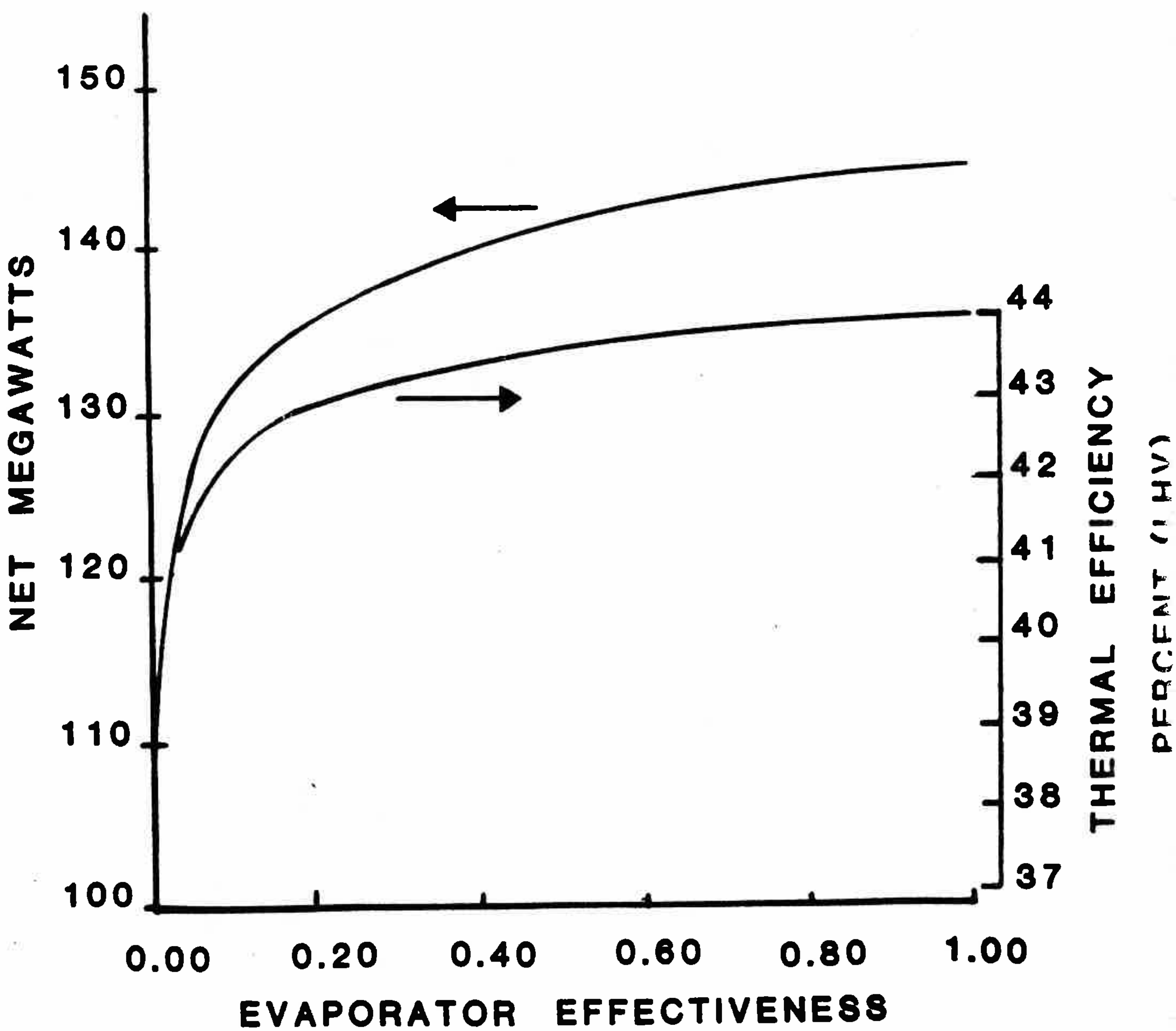


Fig. C. 5. Plant Performance as a Function of Evaporator Effectiveness

Appendix D

Excerpts from the

New Jersey Energy Master Plan

December 11, 1985

<u>COGENERATION</u>

New Jersey Department of Energy
101 Commerce Street
Newark, New Jersey 07102

CHAPTER 3

RECOVERABLE ENERGY SOURCES

COGENERATION

History and Recent Trends

It is now clear that New Jersey can improve its economy, enhance energy reliability, raise energy efficiency, reduce energy costs, lower pollution, convert solid waste to fuel and promote and retain jobs by encouraging the growth of a "new" source of electric power: cogeneration and small-power production by non-utility energy entrepreneurs. These are terms for a method for coupling electric power generators to factories and institutions with a high steam load or demand for heat—whether an oil refiner or a YMCA—and using the heat to produce electricity that can serve the customer's own needs while selling any excess to the utility.

With cogeneration, consumers who are strapped by New Jersey's high electric rates will find that they can convert this liability into an asset. These high costs will act as a spur to investors eager to assist consumers in the installation of cogeneration equipment. Cogenerated power will then replace much of the high cost electricity formerly generated by utilities, leading to lower costs to all, but especially to those cogenerating. In this way, electric power production statewide will gain new generating capacity without the risks or uncertainties associated with traditional utility power plants.

Cogeneration offers wide-ranging economic benefits statewide as well. Lower energy costs resulting from cogeneration make it more attractive for businesses and industries to locate and to remain in New Jersey. Not only are jobs retained in the state, but a company that is investing in a cogeneration facility is not likely to move to another region.

Encouraging the development of cogenerated power would unlock a huge market for cogeneration equipment and services. According to the New Jersey Department of Labor's Division of Planning and Research, constructing 500 MW of cogeneration would create 7,500 to 10,000 jobs for masons, engineers, electricians, plumbers, carpenters, and planners as well as 9,700 to 10,000 indirect jobs in trucking, manufacturing, and other support services, for a total of 17,000 to 20,000 jobs.

In addition, cogeneration in New Jersey will increase the yearly consumption of natural gas, which will benefit all gas customers by spreading the fixed costs of pipelines and gas companies over greater sales volumes. Electric consumers, too, will benefit as cogenerated power sold to local electric companies helps to offset the need for large new central power plants and the importation of power from out of state.

To bring this opportunity to fruition, the State must clarify how electric utilities cooperate with this new energy source which also can compete with utility facilities. New rules are needed to harmonize traditional monopoly regulation with the promotion of non-utility power development. Cogeneration and small power production can then fulfill their immense potential for improving the economy and environment of our State.

In the early years of electric power development, cogeneration was widely used in industrial plants. Gradually, however, electric utilities began to grow and absorb non-utility power producers. In part this growth reflected the new technologies of long-distance power transmission which made centralized electric power plants more economic. In part it also reflected actions by utilities with the support of state and federal regulators which would be questioned today as anti-competitive and monopolistic. See, R. Munson, generally, *The Power Makers* (1985) and C. Wooster, "Cogeneration: Revival Through Legislation," 87 *Dickinson L. Rev.* 705 (1983), pp. 707-717.

By 1920 about 30 percent of the nation's electricity was still cogenerated; by 1950, 17 percent was cogenerated. At the start of this decade, cogeneration reached its nadir—4 percent of national production. It is now sharply on the upswing, however, with over 7 percent of the nation's power generated in this manner and much more on the way.

The re-emergence of cogeneration and other non-utility power sources marks a re-emergence of competitive forces in an arena where natural monopolies have reigned supreme. As BPU Commissioner George Barbour described the change: "Competition has entered the markets for many services long regarded as classic natural monopolies," leading to a "partial revolution" that requires regulators to "reexamine policies" grounded on traditional monopoly theories. (G. Barbour, "Public Utilities Regulation: The Opening of a New Era," 116 *Pub. Util. Fort.*, No. 11 (November 28, 1985) at 15.)

Opening the door to cogeneration means rethinking utility regulation. Promoting an entreprenuerial enterprise, such as cogeneration, cannot simply be grafted onto traditional regulation which assumed the necessity for vertically integrated monopolies with exclusive territorial rights (the horizontal monopoly). In this new era of competition regulation must engage in a "step-by-step and balanced approach" in the transition to a more competitive market in electricity and related services. (G. Barbour, *Id.*) The goal of regulators in 1985 and beyond must be to define where natural monopolies end and competitive forces begin, and then proceed to harmonize the two. This is the regulatory crossroad described by Commissioner Barbour and ushered in by the technological advances and changing economics of electric power production.

Cogeneration is an idea whose time has come again. It is a proven and feasible technology which can be readily employed in New Jersey just as it has in California, Texas and other states where energy businesses have flourished alongside healthy electric utility systems. All that remains is for the State to open up the electricity market and allow investors to compete effectively and fairly with utility power sources. This chapter and the specific policies which follow are intended to produce that result. But in the end the fate of the cogeneration industry will lie with the industry itself and its ability to sell its services to New Jersey businesses and institutions which are eager for a way out of continually rising energy bills. All that the State can and should do is to create conditions favorable for cogeneration to develop at its own pace and on its own merits.

One of the primary reasons for promoting cogeneration is that energy costs have become a critical factor in the ability of states to sustain existing industries and attract new ones. In New Jersey high cost power is an economic concern of the highest priority. Indeed, there appears to be a strong correlation between the level of energy prices in a state and that state's competitive status within the industrial market. *The 1984 Alexander Grant Study on General Manufacturing Business Climates of the Forty-Eight Contiguous States of America* noted that energy costs in New Jersey remained "unacceptably high," despite the fact that New Jersey rose from 47th place to 24th place in terms of overall business climate.

Ownership Options

The ownership and operation of a cogeneration facility can be structured in many ways, which can be compressed into three basic approaches: industrial, joint industrial/utility, and third-party.

Industrial Ownership

In this option the cogeneration facilities are built, owned and operated by the same company or entity which receives the cogenerated power. Both the thermal and electrical energies produced by the system are utilized at the site with excess electrical energy sold to the utility. The majority of the State's existing cogeneration plants fall into this category, including all cogeneration systems which produce mechanical shaft horsepower. Hoffman-LaRoche's cogeneration plant at Belvidere, Warren County is an example of this option. Backup service is purchased from the utility in case of breakdown or scheduled maintenance.

Joint Industrial/Utility Ownership

This option refers to a cogeneration facility owned in part by an electric utility and an industrial partner. The role of the utility may also be assumed by a subsidiary of the utility.

An example of joint ownership is Riegel Paper, where the gas turbine is owned by a subsidiary of NUI, the generator by JCP&L and the waste heat boiler by Riegel Paper.

Third-Party Ownership

This ownership option refers to a cogeneration facility which is owned, operated, and otherwise managed by a corporation formed solely for this purpose. Thermal and electrical outputs are sold to another party or parties.

An example of this option is Trenton Integrated Community Energy System (ICES) project, a government-sponsored system owned and operated by the Trenton District Energy Company (TDEC), which is a private concern consisting of Cogeneration Development Corporation of New York City and a number of general partners. Landlords who generate inexpensive cogenerated power for resale to industrial parks or shopping mall tenants also fall into this category.

Financing

Feasibility Studies: The Department has proposed legislation to appropriate funds for site-specific feasibility studies of industrial cogeneration. Coal conversion studies would be funded from this appropriation as well. The Department has already identified more than 2,000 large boilers which are potential targets for cogeneration. Based upon available information from other states with similar programs, site-specific feasibility studies performed by independent licensed engineers range from $700 to $30,000. The Department would pay up to half of the cost of each feasibility study, limited to a maximum of $5,000.

Construction: The New Jersey Economic Development Authority (EDA) was given the legislative mandate to "guarantee up to 90 percent of the amount of a loan to . . . an energy improvement system." *N.J.S.A.* 34:1B-5(r). Thus, cogenerators are eligible for funding at below prevailing market interest rates. Many small- and moderate-sized businesses will find subsidized interest rates a strong incentive to evaluate the potential for cogeneration.

Potential cogenerators in the main can be expected to turn to traditional lending sources for their investment capital. To do so, however, investors must receive sufficient indication of success if they are to proceed with financing. At present, investors are simply unable to gauge the credit-worthiness of projects in this State due to the unpredictable nature of power sales from the cogenerator to the utility (buy-back rates).

Other economic incentives are available through liberal tax treatment of facilities. These include the investment tax credit and accelerated depreciation allowances. With pending federal tax reform, however, these incentives may soon be ended and cogeneration will be forced to compete even more with other investment opportunities. This likely change in the Internal Revenue Code is further justification for a strong State policy in favor of cogeneration if it is ever to have a chance to develop in New Jersey.

As a rule, economic incentives should not continue indefinitely. Their primary purpose is to provide a sound basis for renewing cogeneration as a means of producing energy. After that, cogeneration must compete on its own merits. Incentives, therefore, must be recognized as short-term benefits which can and should be reduced as the proportion of cogenerated electricity increases. Simultaneously, the liberal tax benefits and related incentives available for the central station generation of electricity should also be phased out so that a truly "level playing field" is created. In the meantime, however, special incentives will be necessary for the re-introduction of cogeneration into the New Jersey economy and energy mix.

In the section which follows the Department sets forth in detail the initiatives that it will undertake to advance cogeneration in the State, the problems faced by this new industry, and the particular solutions that must be employed.

How the DOE Will Promote Cogeneration

The Department will promote the fullest possible economic use of cogeneration in New Jersey in five basic ways.

First, the DOE will continue its public education program.

Second, the DOE will establish a special "Cogeneration Center" at the DOE to assist potential users and developers of cogeneration.

Third, the DOE will work for any legislation needed to end the remaining barriers to cogeneration, so that it can compete on a "level playing field" with utility power sources.

Fourth, the DOE will apply its energy conservation and planning regulations to require utilities affirmatively to plan for the incorporation of substantial amounts of cogeneration and other forms of non-utility, alternative technologies into their supply mix.

And fifth, the DOE will implement this chapter of the Master Plan in every arena of importance to cogeneration, notably in proceedings before the BPU and in the policies of the DEP.

Public Education

On May 23, 1985, over 500 representatives of cogeneration developers, banks, businesses, utilities, and government officials crowded into a room at the Gateway Center in Newark to attend the Governor's Forum on Cogeneration in New Jersey, sponsored by the DOE. Among the companies that discussed their successful cogeneration efforts in New Jersey was Hoffman-LaRoche with its 23 MW Belvidere plant. Other speakers described cogeneration's future as a way to conserve energy, lower electricity bills, and substitute for isolated, single-purpose power plants now in use.

On September 10 and 20, 1985, the DOE held hearings on utility policies regarding cogeneration; gas and electric utilities testified on September 10. On September 20, the DOE heard responses from the cogeneration industry, followed by a concluding session on September 24 due to the overflow of witnesses. These hearings are part of the record in this Master Plan. They have proven to be instrumental in its development.

The DOE plans to hold more seminars, conferences, public hearings and, if need be, investigations, to examine the problems and publicize the promise of cogeneration in New Jersey. These educational sessions will be especially helpful in explaining all facets of cogeneration policies to the public and private sectors alike.

The Cogeneration Center at the DOE

The rudiments of a Cogeneration Center at the DOE are already in place. The Commissioner has pinpointed cogeneration as the leading single initiative of the Department. He has named a member of his staff to work as a full-time cogeneration coordinator. Other offices within the Department devote much of their attention to advancing the cause of cogeneration.

More, however, is needed and clearly justified if this environmentally sound, economic and highly reliable approach to energy efficiency is to reach its full potential. Therefore, in keeping with his power to "organize the work of the Department and [to] establish therein such administration subdivisions as he may deem necessary," (*N.J.S.A.* 52:27F-8), the Commissioner will establish a Cogeneration Center at the DOE. This center will act as a central clearinghouse for cogeneration opportunities; it will mediate problems and disputes; it will cooperate with the Department of Health in its efforts to cogenerate at the many institutions under its jurisdiction; it will assist the DEP in permit procedures; and, perhaps most important, it will be a full-time advocate for cogeneration in the State.

The Center will also contain a registry of cogeneration projects that will enable it to tabulate the growth of cogeneration in the State and to focus attention on projects in need of assistance. In this respect, the center will function much as the Office of Business Advocacy within the Department of Commerce and Economic Development was intended to do—to serve as a proponent of a technology with immense potential to benefit the entire State.

Legislation and Lobbying

The Legislature has passed and the Governor has enacted a bill, S-2531 (P.L. 1985 C. 359), which exempts all sales of natural gas to cogenerators from the Gross Receipts and Franchise Tax. This tax, initiated decades ago as a substitute for local property taxes, has burgeoned into a 14 percent sales tax on all electricity and natural gas sold by regulated utilities. But gas sold to electric power companies, for use in generating electricity is exempt from the tax. Thus, electric utilities have an immediate 14% price advantage over cogenerators. By exempting from tax gas sold for cogeneration, the Legislature has helped to level the playing field of competition between potential cogenerators and traditional utility-supplied electricity. In addition, the Legislature has passed and the Governor has enacted another bill, S-2529 (P.L. 1985 C. 266), which exempts cogeneration equipment from sales tax.

The Cogeneration Center will work with legislators and the Governor's office in promoting the best legislation possible. The center will testify, draft bills, organize coalitions, and generally work for the passage of laws needed and justified to further the public interest in a thriving cogeneration industry in New Jersey.

The Energy Conservation and Planning Regulations

Cogeneration and small power production are among the most efficient and dynamic forms of energy conservation yet devised. They include windmills, waste heat recovery, resource recovery and other forms of alternative technologies. Because a cogenerator, in effect, is able to use the same energy twice, cogenerating both heat or steam and making electricity, a cogenerator is also an energy saver of the highest order.

Moreover, as cogeneration replaces the inherently inefficient use of isolated, single-purpose power plants run by utilities—seldom even half as efficient as cogeneration—we may see net reductions in the use of certain fossil fuels to make electricity, even if these fuels are used in cogeneration. Recent data show that electric power utilities continue to rely heavily on natural gas or oil to make electricity; yet they waste most of the heat created by the burning of these fuels rather than capturing the heat for dual use, as would a cogenerator. For example:

> More than 34% of Atlantic Electric's in-state generation was derived from oil and gas;
>
> Approximately 94% of JCP&L's native generation was oil- or gas-fired;
>
> Some 58% of PSE&G's in-state generation came from burning the same fuels;
>
> And for New Jersey utilities as a whole, about 60 percent of power generated within the State was produced by oil- and gas-fired facilities.

Compared to cogenerating the same amount of electricity through oil or gas, these figures suggest that vital fuels are being used wastefully. A shift to cogeneration and other alternative technologies can change this.

In short, cogeneration can substitute for the burning of oil or natural gas by utilities as part of a comprehensive energy conservation and planning effort. Even if all cogenerators use natural gas, the fuel of choice for cogeneration, there could be a net reduction in fuel used to produce the same quantity of megawatt hours and on-site heat use that would otherwise come from separate utility and on-site heating. In this way we see that promoting cogeneration saves natural gas given the innately more efficient two for one properties of cogenerating heat and electricity.

New Jersey is not the first state to reach this conclusion. The California Energy Commission, for example, has recently published its new energy plan. The Commission counts heavily on cogenerated electricity for much of the State's power needs over the next 10 years. In fact, no new power plants of any kind will be built by utilities in that fast-growing state. See, generally, *The 1985 California Electricity Report: Affordable Energy in an Uncertain World,* C.E.C., P106-85-001 (May, 1985). The Commission tabulates that some 7,300 MW of cogeneration capacity are under contract with utilities; about 2,000 MW are considered "likely to be available" based upon a historical rate of 28 percent of "all identified projects" coming to fruition (*Id.*, at 60, Table 4-5).

In sum, the Department will interpret its Energy Conservation and Planning Regulations (*N.J.A.C.* 14A:20-1.1, *et seq.*) with the above precepts in mind—namely, that conservation and cogeneration are interrelated. Each electric utility's energy conservation plan will include, *inter alia*, its evaluation of "programs designed to promote energy conservation through the use of alternative technologies," including cogeneration (*Id.* at 1.4(a)6). The DOE will then determine if these plans comport with the goals of the regulations and the DOE Act to assure "a secure, stable, and adequate supply of energy at reasonable prices" for the State (*N.J.S.A.* 52:27F-2). To be approved by the DOE, utility plans must show how they promote cost-effective cogeneration and other forms of energy conservation. Utility plans which do not meet this test will not be approved and will, therefore, be amended. Approved plans, in turn, will be enforced through all measures available by law, including (if need be) judicial injunctions and penalties (*N.J.S.A.* 52:27F-21).

Implementing This Master Plan

Finally, and perhaps most importantly, this Master Plan provides much-needed guidance for the future of cogeneration in New Jersey. The Master Plan is intended to show other departments and agencies in the State with jurisdiction over cogeneration how to use their power to promote its widespread use without sacrificing other public concerns. How the agencies respond to this plan is, therefore, critical to the success of cogeneration.

Thus, some explanation of the proper role of the Master Plan in the deliberations of other agencies—notably, but not exclusively, the Board of Public Utilities—may be helpful. (These comments would also apply to any other section of the Master Plan.)

The Department of Energy Act authorizes the Department to adopt a State Energy Master Plan which agencies must implement to the "maximum extent practicable and feasible" (*N.J.S.A.* 52:27F-15b).

This means that, each "State instrumentality" will abide by the Plan as if it adopted this Plan. The only difference may be that agencies are empowered to relax the Plan's demands when it is clearly necessary to do so, based upon evidence that compliance is not "practicable and feasible."

To assist each instrumentality in complying, the DOE may prepare "such guidelines as the Department determines to be relevant" and helpful (*Id.*). Guidelines are offered by the DOE wherever the Commissioner finds a need to provide greater direction and specificity to the Plan than the Plan itself conveys. Since the guidelines are merely explanatory of the Plan, they should be honored in the same way as the Plan itself. The Commissioner has determined that the cogeneration policies and the textual explanations therein are sufficiently precise that no guidelines are needed at this time. (See *N.J.S.A.* 52:27F-15(b) which grants the Commissioner discretion in resorting to guidelines: ". . . The Department shall prepare . . . such guidelines as the department determines to be relevant to assist each such instrumentality in conforming with said energy Master Plan. . .")

Cogeneration: Problems and Remedies

Unless stated otherwise, all references here or in any other part of this Master Plan to cogeneration or small power production shall mean the same as the definition of "qualifying facility" or "cogeneration and small power production" adopted by the Federal Energy Regulatory Commission, 18 *C.F.R.* 292.101 and .202.

At the September 1985 hearings on cogeneration, the Department considered basic problems or barriers which inhibit the economic use of cogeneration. After careful deliberation, the Department has determined that the major inhibiting factors are as follows:

1. Buy-back rates: The rates offered by electric utilities for the purchase of cogenerated electricity are too low, too variable, and too unpredictable. They also fail to satisfy the requirement of PURPA to offer rates based upon the "full avoided cost" in the long-run of cogeneration as a substitute for power plants owned and operated by electric utilities.

2. Back-up power rates and access: Evidence suggests that electric utilities continue to charge rates for back-up power to cogenerators that appear excessive in light of actual experience to date around the country. Pursuant to the Board of Public Utilities Order in Docket 8010-687 (October 14, 1981), utilities were permitted to charge rates based upon an assumed system outage of 15 percent. Experience shows that the outage rate is closer to 5 percent. Excessive rates discourage investment in otherwise feasible cogeneration systems. Now a decision by the Federal Energy Regulatory Commission (FERC) has raised much doubt as to whether third-party cogenerators will have access to back-up power at any price.

3. Wheeling access and rates: Electric utilities continue to maintain barriers to non-utility power sources gaining access to transmission lines for the sale of their cogenerated power to utilities in different service territories. These barriers include unpredictable wheeling rates and non-economic restraints which bear little relationship to the burdens and benefits of installing large quantities of cogeneration on the system. In addition, cogenerators serving more than one facility need to engage in "self-wheeling" in order to take full advantage of economies of scale.

4. Unequal bargaining power: Utilities have unfair bargaining advantages over cogenerators due to the monopsony position of the utility (many sellers but one buyer), the greater risk exposure of cogeneration investors, and other factors. Steps must be taken to prevent utilities from taking advantage of their monopsony status, including the use of standard form contracts and incentives/penalties to promote good faith bargaining with cogenerators.

5. Access to natural gas: Natural gas is the principal fuel of cogeneration, largely due to its clean-burning properties, which are critical to the location and operation of cogeneration units in urban and densely populated areas. Unfortunately, prospective cogenerators have had great difficulty in securing adequate supplies at affordable prices.

6. Environmental permit procedures: Potential developers have complained of difficulty in gaining necessary air pollution and related permits from the Department of Environmental Protection. They also fear the exaction of unreasonable air pollution requirements that may make cogeneration uneconomic.

7. The future of cogeneration in a power-glutted market: There is a persistent concern that cogeneration may be stifled by the continuing, and in some cases growing, glut of uneconomic but utility-owned electric power generating capacity. This concern arises even though cogeneration can supply large amounts of power at rates that are cheaper than much utility capacity, even though cogeneration can reduce net pollution and net energy use, and even though it promotes a more reliable electric power system. This concern is especially pressing in the case of the PSE&G service territory, where most of the State's cogeneration capacity is found.

8. Miscellaneous Concerns:

(a) Evidence indicates that some utilities do not always negotiate in good faith. Regulation is needed to assure good faith efforts to conclude contracts.

(b) To assure least-cost energy for consumers, cogenerators should be allowed to "bid" to displace more expensive power sources, including utility capacity.

(c) While utilities should be permitted to enter the market for cogeneration development, special safeguards are needed to protect competition.

Buy-back Rates for Cogeneration and Small Power Production

One of the thorniest issues of cogeneration is how to compute the buy-back rates for cogenerated power. Many articles and journals have addressed this question, as has virtually every state regulatory commission in the nation, leading often to varied and creative approaches. (See, e.g., C. Wooster, "Cogeneration: Revival through Legislation?" 87 *Dick. L. Rev.* 705 (1983); W. Collins, "Electric Utility Rate Regulation: Curing Economic Shortcomings Through Competition," 19 *Tulsa L. Jour.* 141 (1983); M. Yokell and D. Marcus, "Rate Making for Sales of Power To Electric Utilities," 114 *Pub. Util. Fort.*, No. 3, Aug. 2, 1984, 21-28; J. Schillaci, "The Simultaneous Buy and Sell Provisions of PURPA Section 210 Regulations," 106 8 *Pub. Util. Fort.* No. 8 at 43-45; S. Silverstone, *PURPA Provisions on Cogeneration and Small Power Production* (1980); "The Appropriateness and Feasibility of Various Methods of Calculating Avoided Costs," B-141 (1982) (Draft document, National Regulatory Research Institute); R. Lock, "Statewide Purchase Rates Under Sec. 210 of PURPA," 3 *Solar L. Rep.* 419 (1981); "Calculating Capacity Costs in Cogenerated Rates," 108 *Pub. Util. Fort.* 57, 58 (Sept. 24, 1981); Stirba, et. al., "Implementing PURPA; the Selection of an Appropriate Methodology," 6 *Journal Energy Law and Policy* 91 (1985); and Yokell and Porter, "You Can Avoid Pitfalls in the Sale of Cogenerated Power," *Cogeneration*, 31, Sept.-Oct. 1984. See also, R. Munson, *The Power Makers*, Rodale Press, 1985, and C. Flavin, *Electricity's Future: The Shift to Efficiency and Small-Scale Power*, World Watch Paper 61 (1984) for a broader discussion of the future role of cogeneration.)

How much is a utility required or allowed to pay a cogenerator for electricity sold to the utility? The Public Utility Regulatory Policies Act (PURPA), passed in 1978 as part of the National Energy Act, requires utilities to pay cogenerators at a rate no lower than the "full avoided cost" (FAC) of the utility (PURPA, Sec. 210, 16 *U.S.C.* 824a-3 (1982); and FERC regulations, 18 *C.F.R.* 292.101(b)(6)(1985). In addition, the purchase rate must be "just and reasonable to the electric consumer . . . and in the public interest," and "[n]ot discriminate against qualifying cogeneration and small power production facilities" (*Id.*, at (a)(i) and (ii).

The FAC is defined by FERC as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the [cogenerator], such utility would generate itself or purchase from another source" (18 *C.F.R.* 292.304 (b)(4) (1985). Interpreting these and other regulations has led to a nearly constant stream of litigation, culminating in three United States Supreme Court decisions which appear now to have settled the issue at least enough for development to proceed. These critical decisions are: *F.E.R.C. v. Mississippi*, 456 U.S. 742 (1982) [Supreme Court upheld the constitutionality of PURPA, in particular the decisional duties imposed on state regulatory commissions]; *American Paper Institute v. American Electric Power*, 461 U.S. 402 (1982) [Court upheld FERC's "full avoided cost" formula and interconnection rules against challenge by three utilities.]; and *Consolidated Edison Co. v. New York Pub. Serv. Com.*, 53 U.S.L.W. (1985) [Court dismissed Con Edison's challenge to the constitutionality of a minimum purchase rate for cogenerated power of 6¢ per kilowatthour set by legislation which may exceed the true avoided cost, if set pursuant to FERC rules.]

The *Draft Energy Master Plan* (March 1985) requires the BPU to set rates which "are equal to the fully avoided costs of capacity (present value of new baseload plant) and energy (current average generation expenses of each utility's oil and gas units)" (*Draft Energy Master Plan*, at 132, 135). This approach has been criticized as combining "apples and oranges" because the cogenerator should receive energy payments based on the energy costs avoided by the baseload power plant also avoided. *(In the Matter of the Public Hearings In Re: Draft of the 1985 Energy Master Plan*, September 10, 1985, Statement of B. Parent, at p. 28 [hereafter "Tr." followed by p. number and date]). Since the DOE believes that the appropriate avoided power plant is a "proxy coal plant," the avoided energy cost should be that of coal, not the more expensive oil or gas. It has also been criticized for deviating from the current policy of the BPU, which is to require utilities to negotiate with each cogenerator the costs of purchasing power from the Pennsylvania-New Jersey-Maryland (PJM) grid plus a 10 percent add-on (commonly referred to as "PJM plus 10") for the energy component, and the PJM capacity deficiency payment for the capacity component. *In the Matter of the Consideration and Determination of Cogeneration and Small Power Production Standards Pursuant to the Public Utility Regulatory Policies Act of 1978*, Docket No. 8010-687 (October 14, 1981), at 3 (hereafter "Board's Order") ["We further believe that the setting of avoided energy cost at 10 percent above the PJM billing rate will help to adequately promote cogeneration and small power production in New Jersey. . ."].

The DOE believes that a response to these criticisms is in order. It is important to begin by stating the fundamental steps in determining the FAC as contemplated by the DOE.

The Full Avoided Cost is the Sum of the Capacity and Energy Components

Using an incremental, or long-run, approach to FAC requires that we consider the ability of cogeneration to replace or defer the construction of new utility owned and operated power plants. (Yokell and Marcus, "Rate Making for Sales of Power To Electric Utilities," 114 *Pub Util. Fort.*, No. 3, (August 2, 1984) at 22 (hereafter "Yokell and Marcus"). If cogeneration in the aggregate replaces or delays the construction of a large coal or nuclear power plant, consumers may see a net, long-term reduction in their incremental rates. Rates will be lower than they would have been but for cogeneration, although cogeneration may not reduce rates below their present level.

With cogeneration development total electric power generating capacity will increase without corresponding investments by electric utilities or their ratepayers. Cogeneration also provides other tangible and intangible benefits which do not always show up in consumers' rates. Also known as "positive externalities," these benefits include improved system reliability and efficiency, reduced air and water pollution, and a shift in risk-taking from utility ratepayers to cogeneration investors. (See Flavin and Wooster, generally, and see also Morris, "The Upcoming Boom in Cogeneration", 115 *Pub. Util. Fort.* No. 11, 17-19, (May 30, 1985.). These factors help to explain the federal directive that buy-back rates for cogeneration be set on the basis of the "incremental costs" to the utility (18 *C.F.R.* 292.304.)

The DOE interprets "incremental costs" to mean the capital and energy costs combined of a utility constructing and operating its own new power plant. This view accords with the great majority of jurisdictions and reviewers who have concentrated on this question and resolved it independently, (Wooster, 87 *Dick. L. Rev.* 705, 735-57, *supra*, for a state-by-state listing.)

The question, therefore, devolves into two parts: What will be the capital or capacity component and what will be the energy component of the rate to be paid to cogenerators?

Capital or Capacity Component

Two general methods have been identified to this problem: the Differential Revenue Requirement method (DRR) and the Proxy Unit Approach (PUA) (Yokell and Marcus, *supra*, at 23).

The DRR mirrors what a utility would do in calculating the value of a cogenerator's electricity sales. Essentially, it directs the regulatory authority to find the revenues required under a hypothetical "optimum generation expansion plan over a selected period" assuming no contribution by cogenerators. Then perform the same calculation after "forcing the [cogenerators] into the plan at the assumed time" (*Id.*). Next, subtract the revenues required under step 2 from those required under step 1. This represents the financial value of cogeneration to the utility. Contracts can then be awarded based upon an applicant's share of the capacity allocated to cogeneration in the utility's expansion plan. The DRR has been favored by most utilities.

Practical flaws in applying the DRR approach render it virtually useless to regulators. Foremost among them is the inherent dependence of DRR on a battery of assumptions and data that are often subjective and largely in the utility's sole control. Even if regulatory officials possess the rationale of each utility assertion, it would be burdensome and difficult, to say the least, to test fully the basis and accuracy of each utility calculation on a timely basis. Presumably, the reports filed by utilities under 18 *C.F.R.* 292.302(b), requiring annual avoided cost reporting "on a cents per kilowatt-hour basis," might reflect the data to be used in a DRR approach; but the task of verifying data is enormous. (See *Pub. Serv. Coord. Transp. v. State*, 5 *N.J.* 196, 217-219 (1950) in which the New Jersey Supreme Court admonished the State PUC to probe all data provided by regulated utilities rather than accepting them as true.) Before this task of verification, probably through the adversarial and public hearing method, could be completed, the data would be rendered stale and the process might have to start anew. Meanwhile, much cogeneration would be left in abeyance awaiting the outcome. The DOE, therefore, rejects the DRR method at the present time due to these practical considerations, despite its obvious appeal as a theoretically more thorough and rigorous approach to determining cost-avoidance.

The Proxy Unit Approach (PUA) avoids many of these pitfalls. It is also so simple that most major "calculations can be performed on a hand calculator by anyone who understands the basic elements of utility operations" (Yokell and Marcus, at 23). The PUA looks simply at a hypothetical power plant—assumed to be replaced by many cogenerators—and the costs of financing, building and operating that unit. (Compare this method to the difficulties in examining the entire utility expansion plan over several decades of the DRR.) The PUA allows the regulatory officials to break the question down into the relevant, manageable parts, such as:

—What is the proxy unit? (e.g., fuel, size, location, operating characteristics, etc.)

—What is the timing of the proxy unit? (e.g., when would it be needed but for the cogenerators?)

—How much will the proxy unit cost?

—How reliably would this proxy unit operate?

—What is the present value of avoiding this proxy unit which can therefore be awarded to the cogenerators and form the basis for their compensation?

Determining The Proxy Unit

There are at least four ways to decide on the proxy unit. Each has several problems, but one has benefits that ultimately outweigh its difficulties.

The Utility's Most Recently Completed Unit: The obvious benefit of this approach is that it yields objective and specific numbers. All can see the costs actually incurred and passed on to ratepayers in the last power plant built. The problem is that the newest power plants built by New Jersey's electric utilities, except for Rockland Electric, have been nuclear power plants. Hope Creek, at $3.8 billion or higher, is so costly that if it is used as the basis for cogeneration planning, excessive buy-back rates might be produced. No New Jersey utility is likely ever again to spend so much on a single power plant, with or without cogeneration. More cogeneration than is justified could be stimulated, and ratepayers might pay rates that are unjust.

The Utility's Next Power Plant: The benefit of this proxy unit is that it may actually conform to the facility that cogeneration will displace. This proxy unit has much certainty and realism to it. However, it leaves too much within the discretion, control and judgment of the utility which may have a strong interest in deterring non-utility power sources within its service area. A utility could stifle the growth of cogeneration simply by altering its demand forecasts and resource plans at will. It might publicly plan on no more power plants for the foreseeable future and assign a "zero" value to cogeneration. Then when cogenerator investors are deterred from competition with the utility, it can reverse itself if need be and resume planning for a power plant or power purchases which healthy competition from cogeneration might have avoided. This approach, therefore, suffers from a potential for "bait and switch" manipulation that renders it unfair and unreliable.

The Utility's Next Unit After Certification by the DOE: This approach borrows from the preceding approach, but it has the balancing effect of an outside review by the DOE that will require each utility to submit detailed plans for energy conservation (*N.J.A.C.* 14A:20-1.4 through 1.8). Once the DOE has reviewed and approved the utility plans, it may then certify them (*Id.* at 1.9). In this way, a finding may be forthcoming as to what the appropriate avoided power plant will be with respect to each utility. The advantages to this approach are numerous. DOE reviewers can determine on a utility-specific basis what is the optimum plan for that utility. How much conservation investment should the utility plan to accomplish? How much will this defer the need for power generation or purchase, whether from PJM or from cogenerators? Clearly, such a planning process can work. However, it may not be suitable to the singular purpose of identifying a proxy unit and the consequent setting of avoided cost rates to be paid to potential cogenerators. Delays can be expected in the process of preparing, submitting and reviewing of utility plans. These delays could forestall otherwise justified cogeneration development.

More to the point, this planning process is directed primarily toward the promotion of conservation, particularly in the residential sector; it is still the least costly, most environmentally sound form of energy development (Draft Master Plan, at 157, 173). It would be anomalous if promoting residential conservation should serve to bar, even temporarily, the cost-effective development of commercial and industrial cogeneration. Both merit support and devoted attention. And, since much of the conservation initiative will be limited to residential and small commercial ratepayers, it is only fair and proper that cogeneration should proceed at its own legitimate pace, given its strong benefits to industrial and large commercial users who have had to fend for themselves in coping with rising electric rates.

In due course, the DOE believes that it will be able to fine tune the planning process so that the cogeneration and conservation initiatives are effectively merged. The conservation regulations contain many inducements to cogeneration that will directly benefit this effort as well. Nevertheless, until such time, the DOE finds that there is a clearly preferable methodology.

The Hypothetical Statewide Power Unit: The most practical approach to a proxy power plant is to determine the hypothetical power plant on a statewide basis exclusive of statewide conservation developments. Such a pragmatic approach recognizes the statewide regulation and interconnectedness of the investor owned power companies. It also reflects the regulatory simplicity of identifying one unit that would, in fact serve all the users of the State at varying times due to power exchanges and interconnections. Furthermore, it removes the opportunities for a utility to "bait and switch" and eliminates the delays and regulatory expense of engaging in laborious company specific assessments of power plant investment decisions that are still several years away.

What is New Jersey's Statewide Proxy Power Plant?

As stated in the March, 1985 Draft Master Plan, the DOE is convinced that the appropriate statewide proxy unit is a hypothetical baseload coal-burning power plant. When it is needed could be the subject of debate. (See, e.g., the Electric Facility Need Assessment Act. *N.J.S.A.* 48:7-16, et seq.) Historically, State regulators have had little involvement in formal reviews of the need for new facilities. The related question of timing, i.e., when a power plant justified for billing to consumers and bringing into operation, has received only minimal attention as a rule. Thus, it would seem anomalous to apply a stricter standard to small, non-utility facilities than was applied to large, utility units over the years. Nevertheless, new facilities can be justified and, indeed, are needed whenever they will reduce electricity costs, lower acid rain deposition from State dependence on out-of-state coal plants or generally enhance system reliability.

A review of the existing installed capacity of the New Jersey utilities indicates that as of December 31, 1984, it was 13,278 MW. However, significant amounts of firm capacity purchases are presently being made by ACE and JCP&L. As of December 31, 1984, these firm purchases were about 1,400 MW. Some of these purchase contracts will start expiring in 1992 over a nine-year period. In order to continue providing adequate service, the utilities would, absent massive conservation and cogeneration programs, need to build new facilities. The most likely candidate for this capacity expansion would be a coal-fired plant in the size of 600 MW.

It might be expected that this plant would burn primarily low sulphur coal at 1.5-3.5 percent sulphur content in order to conform with New Jersey's strict air pollution control limitations. (See, e.g., *N.J.A.C.* 7:27-7.1, *et seq.*; sulphur content; 7:27-10.1, sulphur in coal; 7:27-5.1, general prohibitions, 7:27-8.1, permits and certificates; 7:27-13.4, ambient air quality standards for sulphur dioxide, and 7:27-3.1, further controls on combustion of fuels.) It would also be equipped with scrubbers and other air emission elimination systems, consistent with the requirements of the "State Implementation Plan" adopted by the DEP. *N.J.A.C.* 7:27-13.2(a)-(c).

Such a plant could be installed in 1992 at a cost of approximately $1,900 per KW in current dollars. In order to compute the capacity payments for this proxy plant in 1992 to be paid to a cogenerator in 1986, the DOE suggests using the methodology developed by the State of Florida. Under the Florida methodology, monthly capacity costs in dollars per KW are calculated for the proxy unit. The savings associated with deferring this unit for any length of time is then calculated, and this amount is paid out to the cogenerator over the life of the cogeneration contract. With this technique, for the New Jersey proxy plant to be built in 1992, a cogenerator in 1986 would receive a capacity payment of $12.27 per KW per month for a 10-year contract. This translates into approximately 2.4¢ per kwh for a 70 percent capacity factor.

The Energy Component

Logically, it would seem that the energy component of the proxy power plant should serve as the basis for compensating the cogenerator for energy actually delivered. If the cogenerator displaces a unit of coal power plant, then both its capacity and energy payment schedule should be based on the same unit. This reasoning formed the heart of comments by the BPU and PSE&G. They referred to the DOE's proposal that cogenerators be paid for capacity based upon a baseload coal unit and for energy based upon a gas or oil-fired peaking unit as an "apples and oranges" approach.

The DOE remains convinced that there is a sound basis for combining apples and oranges, yielding in this case an energy "salad" for the residents of New Jersey. This is so for the following reasons:

—As a rule, cogeneration facilities burn oil or natural gas. Since cogenerators must purchase these relatively high-cost fuels, they deserve to be paid for their efforts just as a utility "passes through" its fuel costs (*In the matter of Redi-Flo Corp.*, 76 N.J. 21 (1978). Also, if they are ever to compete "on a level playing field" with utility power plants, they may require temporary incentives. This incentive factor both compensates for incentives routinely given to utilities and recognizes the many intangible benefits of cogeneration. Indeed, in the BPU's original orders of 1981 in Docket No. 8010-687 regarding the buy-back rates for cogeneration, the Board added a premium of 10 percent to the PJM billing rate—hence, PJM plus 10—expressly due to these external benefits. ("[W]e are of the opinion that there is intrinsic value to smaller, decentralized cogeneration and small power production facilities." *Board's Order*, at 4.) Since 1981 the public has come to appreciate that these benefits far exceed their previous estimates. They include burning alternative fuels; using energy more efficiently; enhancing reliability for electricity supply; reducing consumption of oil or natural gas by electric utilities; increasing economic security for industrial and commercial ratepayers; lowering acid rain in the State; and the secondary benefits of having a thriving "emerging technologies" industry in the State (See J. Cannon, *Acid Rain and Energy: A Challenge for New Jersey*, [Inform, Inc., 1984]. For a report on one state's efforts in this regard, see *The 1985 California Electricity Report: Affordable Electricity in an Uncertain World*, Cal. Energy Comm., P106-85-001, at 143.)

—New cogeneration facilities replace both peaking and baseload units. Given the short lead-time for constructing and installing cogeneration facilities, they offer the promise of substituting for high cost power generation of all types in a very short period. For the next few years, cogeneration investors can quickly displace otherwise uneconomic power generation and purchases. In so doing, the current price of oil and natural gas is the appropriate avoidance standard for compensating these investors, especially given the continued dependence of utilities on natural gas and oil as fuel sources at power plants in-state. Eliminating these inefficient and uneconomic uses of prime fossil fuels should be a leading objective of the State.

The Department recognizes that setting the avoided cost rate must also take into consideration the interests of non-cogenerating ratepayers. If cogeneration can be stimulated at a lower rate, then all public interests are better served. This balancing factor is well recognized (See e.g., 18 *C.F.R.* 292.304(a)1). ("Rates for purchase shall . . . [b]e just and reasonable to the electric consumer of the electric utility and in the public interest.") Consequently, the Department has determined that the energy component shall be that of the most efficient baseload oil- or gas-fired steam units.

The Department agrees, however, that the energy component should be reduced to the avoided energy of a baseload proxy unit as of the date when that power plant theoretically would be needed. In other words, if the coal unit is assumed to be needed, but for cogeneration, in 1992, then as of 1992 the energy component should be based on a coal plant in that same year.

In this way the DOE has created a kind of "two-tier" pricing policy. In the first tier are cogenerators who respond swiftly to this Master Plan, sign contracts, and otherwise serve as pioneers for those who will follow. (Pennsylvania calls this a pioneer rate). Being among the first should merit special consideration. Those who follow will reap the benefits of their successes. They will find an easier regulatory path, assuming their product is competitively priced. Accordingly, those who invest after 1992 should receive an energy rate equal to avoided coal-fuel costs in the same year. Non-utility power producers in operation before that year will receive the premium rates based upon oil or natural gas steam units until that same year.

An Alternative: Locked-in PJM Rates

The electric power utilities, as stated, continue to support retention of the Board's pricing policy announced five years ago. This policy reflects a spot-market approach which has slowed cogeneration investment in the State. It may be, however, that one of the most basic flaws in this approach—its unpredictability—can be corrected. Since utilities routinely project future trends in the PJM billing rate, as central to their planning for new facilities, there is no reason why cogenerators should not also enjoy the benefits of that forecasting. The trend lines for the PJM billing rate could serve as the trend line for cogeneration buy-back rates. This would alleviate much of the unpredictability in the 1981 BPU order. A cogenerator should be able to choose a locked-in trend in the projected PJM billing rate, just as a utility relies on this information to foreshadow its investment decisions.

Accordingly, cogenerators may select a contract for buy-back power rates using the "ramped-up" PJM billing rate for the energy component as the formula for their compensation. Whether the 10 percent premium should be increased, as seems likely, is another question. Such an option may be simpler than the proxy unit method; it also may be faster than the PUA. It will, in any event, be up to the cogenerator to choose.

Summary

The State must alter its pricing policies to attract and retain cogeneration investment. Therefore, the DOE adopts a two-tier pricing plan, using the proxy coal unit for capacity costs together with the energy cost of a baseload oil or gas unit until 1992, when it will shift to the avoided energy cost of the same coal unit. Alternatively, a cogenerator may choose to use the PJM billing rate (plus some appropriate premium, 10 percent under the BPU's 1981 orders) that is locked in to a projection of the future PJM billing rate. This rate will be likely to escalate in keeping with rising PJM billing rates; therefore, it is also a ramped up rate that will guarantee an increasing revenue stream to a cogenerator, provided it performs to expectations.

In fashioning these rates, the State must be careful to provide incentives only where cogeneration actually takes place. The Department therefore proposes that the rates described in this Plan apply only to power supplied by cogenerators to utilities beyond a cogenerator's own needs. Cogenerated electricity must be based upon the principles of thermal dispatch of power. Naturally, any rates established under these criteria must be fair to existing customers, include a consideration of the long-term reliability of the qualifying facility and cover the cost of any transmission enhancements required to interconnection.

Back-up Power Rates and Access

Few industries would invest in cogeneration without the availability of the utility's electricity when the cogenerator needs repair. Historically, refusal to deal with cogenerators enabled the utility industry to drive them out of business (Wooster, 87 *Dick L. Rev., supra.*

at 712-14). PURPA and the regulations of FERC now guarantee that utilities must not discriminate against cogenerators in the sale of back-up, maintenance, supplemental or interruptible power (16 *U.S.C.* 824 a-3(b), and 18 *C.F.R.* 292.305). Of special note, FERC regulations and the BPU's orders prohibit utilities from projecting that all cogenerators will be off-line at the same time, a technique used in the past to charge them an excessive demand charge (based on the fiction that the utility will reserve capacity for their use at all times, even when not needed) (18 *C.F.R.* 290.305 (c) (1).).

The BPU's 1981 orders authorized a demand charge predicated on the assumption that cogenerators as a group would be off-line 15 percent of the time. (See p. 6 of the October 14, 1981 order which describes the Board's "assumption of diversity" of 15 percent at the generation level.) More current experience, however, shows that even this rate is too high. Nationally cogenerators have a group outage rate closer to 5 percent. Therefore, barring any experience to the contrary unique to New Jersey, the State should use this lower figure in calculating back-up power rates. Doing so also conforms with the caveat in the BPU's original order that "such charges and their underlying assumptions should be reviewed as soon as more data is available." (*Board's Order*, p. 6.)

Unfortunately, a recent decision by FERC undercuts this protection for many cogenerators. In the *Alcon* decision, FERC ruled that the utility must supply back-up power only to the actual owner and operator of the cogeneration equipment, but not to the industrial customer of the cogenerator (*In the matter of P.R.E.P.A (Alcon)*, FERC Docket No. QF 84-147 (1985). Over a third of all cogeneration is the product of third-party financing and operation where cogeneration specialists, taking advantage of tax incentives, operate the facility for the industrial purchaser of the steam and electricity. The Alcon decision could stifle third-party investment.

There is a simple way to avoid the harsh and restrictive nature of the Alcon case. State regulatory officials can order utilities *under state law* to provide full back-up, supplemental and maintenance power at affordable rates to third-party cogeneration (See, e.g., *N.J.S.A.* 48:2-13, -16, -23, -24, and -27). Utilities in New Jersey must provide such nondiscriminatory service at fair rates to all cogeneration facilities, regardless of who in fact owns title to the hardware or operates the equipment.

Besides the rates to be charged for cogeneration back-up, there is much concern over the non-economic aspects of gaining access to the utility system. The industry complains of long delays by utilities, indecisive and unresponsive negotiations, refusals to interconnect with the utility's network, high costs to interconnect, unreasonable and repetitious demands for safety and compatibility assurances, and other forms of apparent passive resistance (See, e.g., Transcript of September 20, 1985, statements of J. McNair, pp. 127-28; R. Topper, p. 147; J. Barnes, p. 161, 162). These problems can be as discouraging to investors as the economic difficulties described above.

Accordingly, the Department and the BPU will order utilities to cease and desist from any behavior that unreasonably delays or frustrates a cogenerator's request for access. The BPU will assist in the identification and prevention of any form of stalling tactics, recalcitrance or anti-competitive behavior. Much of this problem, it is expected, will be resolved in the standard offer contracts which a cogenerator will be entitled to sign and enforce against the utility, and in other protections against bad faith bargaining.

Wheeling Access and Rates

Control over transmission lines has helped electric power utilities to eliminate competition by public or municipal systems. (Indeed, a crucial development in the history of the electric utility was the invention of long-distance transmission. See, e.g., R. Munson, *The Power Makers*, 50-52.) Such concerns motivated the U.S. Supreme Court in *United States v. Otter Tail Power Co.* to order a private utility to allow a municipal utility to transport power across its franchise area using its transmission network, even though the two were *de facto* competitors (410 U.S. 366, 377 (1973). (The Supreme Court relied upon the finding that "Otter Tail has a 'strategic dominance in the transmission of power in most of its service area' and that it used this dominance to foreclose potential entrants into the retail area from obtaining electric power from outside sources of supply." (See discussion of Otter Tail as a classic example of the "bottleneck monopoly" in "Refusals to Deal by Vertically Integrated Monopolists", 87 *Harv. L. Rev.* 1720 (1974).)

In the same way, utilities have a long history of using transmission line monopoly to stem the entry of potential non-utility competitors—namely, cogeneration and small power production—into their service area (R. Munson, *supra*, 55-71). Some journal writers now believe that the only "natural monopoly" remaining in electric power lies in the long-distance transmission of electricity at high voltage (Cohen, "Efficiency and Competition in the Electric-Power Industry, 88 *Yale L. Jour.* 1511, 14-18, citing numerous authorities, which recognizes the continuing "economies of scale in bulk-power supply," as contrasted with the increasing diseconomies in large-scale central station power generation.) Typically, the situation arises where an industrial firm seeks to generate its own power and sell the excess to the local utility; when this request is denied, the factory may try to sell the output to another utility or to buyers outside the service territory. Typically, as well, this request to wheel the cogenerated power has been denied or subjected to onerous conditions and uncertain rates.

PURPA and implementing FERC regulations, however, show that Congress intends for cogenerators to be able to sell their power to other utilities through fair access to wheeling services (18 *C.F.R.* 292. 303 (b), (c) and (d).). But much discretion remains in FERC and at the state level as to what the wheeling charges may be and how to resolve other wheeling controversies. At least one state, Texas, has assumed complete control over intrastate wheeling (*Cogen Rept.*, Oct. 11, 1985 at 5). In New Jersey and most states, however, wheeling rates may be subject to FERC regulation.

Often as important as wheeling charges is whether the wheeling utility may assume line losses in the wheeling contract. In the typical utility-to-utility wheeling, power is brought in from afar and some line loss might be expected as the local utility picks up the power at its border and transmits it elsewhere.

Since cogenerators export rather than import power, the situation is reversed. In most states which have considered the issue, it is recognized that cogeneration results in negative line losses. That is, the additional increments of non-utility power added to the lines help to offset line losses otherwise experienced by the utility. Cogenerated power is generally produced at a location which is closer to the load than the utility's power plants. When cogenerated power is wheeled, electrons are not transmitted to the far-away purchasing utility. Instead, they are fed into the grid, and power is delivered to the purchasing utility. If the cogenerator is located close to major load usage in the transmitting utility's service territory—usually the case, especially in densely populated and heavily developed New Jersey—the added power will reduce overall line losses as if it were sold to and used by the host utility.

The line loss issue is often crucial. A utility can experience a 5 percent line loss in transporting power from its border to another utility; but if a comparable level of cogeneration is near a large load, the utility should expect a savings of approximately 5 percent. Instead of being charged for line losses, therefore, cogenerators in this situation should receive a credit.

Two New Jersey-based utilities, PSE&G and JCP&L, have expressed a willingness to wheel on certain conditions. ACE however, and to a lesser extent JCP&L, have raised the contention that the State should not require wheeling by a utility on a long-term or firm basis. ACE argues that its transmission system was built for and paid for by its franchise customers and they must have first priority. ACE also argues that its transmission lines are already loaded at 98 percent of its capacity on a year-round basis. If so, then it appears certain that ACE, located in a fast-growing area, will need to expand its transmission capacity in any event. Cogenerators as a class can reduce loading on bulk power transmission lines if they export power or engage in simultaneous buy-sell transactions in which no power is exported to the grid. Thus, a transmission capacity credit would seem particularly appropriate on ACE's system.

ACE's argument that its transmission capacity was built for and is being paid for by its franchise customers misses the point of wheeling services to cogenerators, also among their customers. Wheeling can reduce the costs of transmission services otherwise absorbed by other ratepayers because cogenerators should pay their fair share of transmission capacity. In this respect, if ACE or any other company fails to provide wheeling services when capacity is available, it imposes unnecessary costs on its other customers.

Furthermore, it appears incongruous to deny wheeling services to cogenerators that will provide power efficiently, reliably and within the State while providing such services to out-of-state utilities—which is routinely done through PJM interaction. JCP&L imports 70 percent of its power requirements and ACE has contracted for large power imports from Pennsylvania Power & Light; much of this power could be provided in-state through efficient cogeneration that also may reduce acid rain from Pennsylvania coal plants. In-state cogeneration that can wheel from one utility to the next will help right these imbalances.

Setting wheeling rates may be the province of FERC, but there is every indication that the federal regulators will defer to proposals by the states. The methods employed in Texas are noteworthy and may be applied in New Jersey. Two approaches that were debated were a boundary method and a megawatt mile approach. Reportedly, the Texas PUC arrived at a hybrid method that will provide some compensation to all affected utilities and at the same time provide for a stable, easy-to-calculate and verifiable approach.

The New Jersey BPU will be called upon to adopt without delay a similarly definite and fair method of determining wheeling rates and terms of service. (In its 1981 order the Board directed that "[a] Phase II proceeding be established to consider the issue of wheeling within the State of New Jersey." *Id.*, p. 11. On November 13, 1985, the BPU called together various electric utilities for a conference to begin discussion of a BPU wheeling policy.) The goal must be to establish a statewide market for cogenerated power that allows it to be used where it is most needed. In addition, cogenerators should be permitted and encouraged to engage in self-wheeling in which they wheel power from one or more facilities to multiple customers. In this way the most optimally-sized cogeneration system can be constructed and put into operation without running the risk of being charged excessive wheeling rates or being declared a public utility.

Unequal Bargaining Power and Standard Offer Contracts

An electric power utility is both a monopoly and a monopsony. It is a monopoly because it is the only company authorized by law to generate and sell electricity to other customers within a designated service territory. It is a monopsony because by law all non-utility power providers are limited to selling all their excess power to the same utility or risk being declared a public utility (Hamilton and Bros, "The Need for Standard Contracts and Prices for Small Power Producers," 115 *Pub. Util. Fort.*, No. 11, May 30, 1985, 24-32).

Such a position of power—as the sole buyer and seller—creates an unequal bargaining situation which can frustrate and stifle the entire cogeneration effort. The monopsonist utility can raise entry barriers through subtle exactions, called transaction costs. It can, for example, discourage cogeneration by engaging in drawn-out contract negotiations requiring time and expensive expert assistance; the utility's time and costs will be passed on to ratepayers, but the cogenerator must bear its own. The utility can say it is eager for cogeneration, but it can rotate negotiators, so that each one must start the process anew; or it can send negotiators who lack expertise or the authority to close a deal. By imposing unfavorable take-it-or-leave it contract terms, the utility can simply dictate its own bottom line all too often.

Such monopsony abuses are not merely theoretical; they are actual and historical. They were at the heart of the *Otter Tail* decision, discussed earlier, which found the utility's practices to be in violation of federal antitrust laws. They were also singled out repeatedly and frequently by cogeneration witnesses in hearings before the DOE as characteristic of their own experiences (See, e.g., Tr. statement of P. Maistro, p. 213). Thus, it is imperative that clear, enforceable and definite measures be in place if we are to even the bargaining positions of the utility and the would-be cogenerator and reduce transactional barriers to a minimum.

The best approach to correcting these problems is to establish standard offer contracts. This approach is used in California with unprecedented success; it is also the approach favored by journal writers and by the cogeneration industry (Hamilton and Bros, *supra.*) And, while it is opposed by New Jersey's electric power utilities, they have failed to bring forth reasons to support their opposition, other than the simple truism that each cogenerator is different.

The standard offer contract is a uniform contract with the essential terms already filled in and approved by the State. (Logically, a variety of standard offers may be approved by the State, depending on such variables as whether the cogenerator will use renewable fuels or burn solid waste, the size of the cogenerator, and other factors.) The contract empowers the cogenerator to sign the contract "as is" or negotiate any condition it wishes. But the utility cannot refuse the contract as signed. Once the cogenerator has signed it, the contract is an enforceable legal instrument *(Id.)* In this way, bargaining positions are more nearly equalized, and if negotiations flag, the cogenerator always has the option of fixing his signature to the bottom of the page.

The outline of such a contract at a minimum should include the following:

Part I. Business Relationship to the Utility .

A. Status with FERC as a qualifying facility.

B. Purchase price for power and method of payment to the non-utility producer.

C. Price for back-up power and method of payment to the utility.

D. Cost of interconnection and method of payment.

E. Liability.

F. Liability insurance.

G. Access to producer's facilities.

H. Conditions for interruption of

1. power to the facility, or
2. power from the facility.

I. Notice requirements for interruption.

J. Penalty clause for nonperformance of any provisions in the contract.

K. Dispute resolution and arbitration.

Part II. Technical Relationship with the Utility (including safety features)

A. Conformance to applicable laws, codes, regulations and ordinances.

B. Technical requirements for

1. interconnection and
2. operation.

The most important single element in this contract is the price for power: How much can the potential investors expect in the revenue stream from this facility? Since New Jersey will adopt a statewide proxy unit method of calculating buy-back rates, together with a pioneer rate for energy, this will be filled in at the conclusion of that process of determination. Alternatively, for those eager to proceed in the interim, the locked-in projection of the PJM billing rate—together with a premium for the environmental and social benefits of cogeneration—may also serve as one contract rate. (The Legislature could even establish a "floor rate" as it did in New York; this rate would then be the minimum for the benefit of a cogenerator.)

Access to Natural Gas

Cogeneration facilities can use almost any combustible matter as their fuel. Some units burn almond shells, corn husks, sawdust, and other forms of waste, including municipal solid waste (resource recovery). Others are not cogenerators at all, but are wind-powered forms of small-power production. Still others will use coal. Most, however, rely on the cleanest burning fuel possible, natural gas. With the end of the gas crisis of the 1970s, natural gas is in abundant supply; but a combination of factors has made it difficult for this gas glut to translate into low prices for all users, including cogenerators. Yet gas is clearly the best fuel, particularly because of air quality standards in New Jersey. As a result, no cogeneration policy is comprehensive without making provision for access to natural gas.

Until very recently, many industries were turning to direct purchases of gas from producers far from New Jersey as one way to beat the high cost of gas delivered by Local Distribution Companies (LDC's or gas utilities). However, a court order in *Maryland Peoples' Counsel v. FERC*, 761 F. 2d 768 (D.C. Cir. 1985), and 761 F. 2d 780, and the rising tide of competition in gas transportation services have led FERC radically to alter the rules of gas transportation in Order No. 436.

Interstate pipelines historically purchased gas from the well-head producers, then sold it in bulk to the LDC's which re-sold it retail to the public. The new FERC policy gives pipelines a fundamental choice. Either they can transport all gas on a nondiscriminatory policy or they may not transport at all. They no longer may transport gas to some customers and not for others or charge what FERC labels as discriminatory or preferential rates. (They can of course, continue to transport and sell their own gas.) While a policy against discrimination appears basic to fairness, it may not lead to the result sought by FERC—more competition in the interstate natural gas market. When the pipelines are glutted with their own high-priced gas which they cannot sell, they are naturally reluctant to transport cheaper gas through their pipelines to cogenerators buying gas from others.

As this transition to the new FERC rules evolves, cogenerators have three choices on fuels: First, they can choose to use non-traditional fuels, such as solid waste or even coal. Second, they can choose to burn natural gas. Or, third, they can choose to burn oil.

The first is highly desirable, where it can be accomplished safely and without harm to the environment. Indeed, it is State policy to encourage or compel counties to plan for the ultimate disposition of municipal solid waste in resource recovery facilities that will generate electricity (*N.J.S.A.* 13:1E-6(b)(1) and 1E-93, and 48:13A-1, *et seq.*). See also, Part One, Chapter 3 of this Master Plan. However, siting waste-to-energy plants will prove difficult and controversial, as with landfills.

If a firm can burn low-sulphur coal or coal in a fluidized bed or otherwise comply with air quality standards, it should be encouraged to do so. Coal, however, has not yet proven itself as an attractive fuel for urban cogeneration projects, especially smaller ones.

This leaves natural gas or oil for most users. The former is clean to burn, which makes it highly desirable in urban settings where so many cogeneration projects can be expected. The latter is not nearly so clean and comes primarily from foreign imports. But at least there are oil dealers from which to choose.

The DOE believes that natural gas is by far the preferred choice. Without transportation gas, utilities must provide gas to these users on a reliable and affordable basis. (If not, some companies may be forced to construct their own connections to interstate pipelines, by-passing the LDC entirely.) Many gas utilities seem eager to provide all the gas they can. They recognize that gas for cogeneration will be an excellent load leveler: It will help to balance the gas company's (winter) heating-peak season with the electric utility's (summer) cooling-peak season. By selling large quantities of gas in the summer to a cogenerator, which in turn sells power to a utility straining to meet peak demands, both utilities appear to benefit along with the cogenerator.

Environmental Permit Procedures

Siting cogeneration units in a densely populated, heavily industrialized state can be difficult. The DEP routinely requires a variety of permits for any industrial, fuel-burning installation. Cogeneration is no exception. Of special concern to the industry is how long it takes to receive permit approval. (Tr. statements of R. Toppe, at 146; B. Trobaugh at 196, P. Maistro at 211, and H. Kociencki at 220, September 20, 1985.) In addition, investors worry that costly selective catalytic converters will be required on all new installation, should California's Air Resources Board adopt such a rule and other states, including New Jersey, follow suit.

The DOE believes that the DEP should recognize the positive environmental externalities conferred by cogeneration, including reducing acid pollution from western coal plants. The latter is the cause of almost all the acid rain that now harms so much of the country, especially the East Coast (J.S. Cannon, *Acid Rain and Energy: A Challenge for New Jersey* [Inform, Inc., 1984], at 2.). Acid rain, in particular, is produced by large coal-burning power plants that supply New Jersey with much of its energy.

Therefore, the DOE calls upon the DEP to establish a rapid, one-stop permitting process for cogenerators that will lessen out-of-state energy dependence. The environmental agency should be vigorous in seeking out ways to offset the pollution generated at the facility (pollution offsets). Giving the facilities explicit credit for their contribution to New Jersey's acid rain efforts is clearly justified.

Cogeneration in a Power-Glutted Market

California has led the nation in promoting a successful cogeneration industry. In less than five years installed cogeneration capacity has jumped from 300 MW to about 2,000 MW with still more under negotiation *(The 1985 California Electricity Report, supra.)* The California Energy Commission and the PUC are now facing the problem which the utilities had told them could never happen: too much cogeneration capacity.

Some commentators fear that a cogeneration glut could lead to a death spiral in electric utilities. As more customers generate their own power and sell back to the utility, which is obligated to buy, fewer customers will be left to pay the fixed costs of the utility. The utility will then raise rates to the remaining customers, which will lead to still more customers leaving the system, cogenerating their own power, or simply increasing their conservation. This concern is especially troubling for utilities which are just finishing costly nuclear power plants. Such utilities may call for caps to be placed on new cogeneration capacity. Alternatively, they may do all in their power to discourage cogeneration through whatever legal means are at their disposal.

Restricting the amount of new capacity from these other sources is at best a short-term solution that would impose substantial hidden costs on the public. The public will pay more than it should if potential cogenerators are denied the opportunity to supply the public with lower cost energy. Setting a limit on cogeneration is roughly akin to tariffs, import quotas and other trade restrictions that may protect certain interests but only by transferring hidden costs to the public. At the same time, the existing utility network must be maintained. Accordingly, some method must be found for encouraging constant innovation and competition but without undermining the basic infrastructure in electricity that is the hallmark of the utility industry.

The DOE believes that there are several approaches to this problem. No utility power plants should be exempt from the competitive forces of non-utility power. Nor should non-utility sources be shielded against the winnowing effects of market forces. The best solution is one which follows the least-cost principle of promoting economic dispatch of power sources, whether they are owned and operated by utilities or by non-utilities.

Placing all power generators on a level playing field is the logical next step in the revolution in electric power regulation and development unleashed by PURPA. There is no need to place an arbitrary lid on new power, if each new increment survives a rigorous test of the marketplace. Simply put, there is no glut of power if adding more capacity means lowering production costs, reducing consumer bills, or reducing the pollution caused by single-purpose power plants. This new, decidedly more open system would resemble the growth era of the 1950s and 60s when each new utility project capitalized on economies of scale and reduced cost and rates to all. The major difference here is that the test of need for new capacity would be based upon market forces. Also, much of the new capacity would be non-utility units that displace utility units; just as new utility capacity in those years often drove non-utility sources out of operation.

In such a competitive setting, if "new" power sources replace the "old" sources, the latter could then be written off (perhaps mothballed, placed under new management, or sold off) if found to be obsolete. the uneconomic units would no longer be "used and useful" to consumers. Therefore, they would not be charged to ratepayers. This approach avoids the "Catch-22" that competition will lead to higher rates even when the competitors will supply electricity at lower rates, because utilities may charge ratepayers for economically obsolete capacity. If a facility—whether it is a cogenerator or a utility unit—cannot compete, then the State must not tolerate its forced subsidization by the public. Such a process might be characterized as one which focuses on the fully avoidable cost to the consumer, not to the utility, although in the long-run the result should be the same.

Change and innovation would substitute for the static concept that utility facilities, once approved, stay in the rate base until they are too old to operate or until they are replaced by new utility units. With *de facto* and *de jure* competition ushered in by cogeneration and other non-utility power sources, the power supply industry might resemble the automobile retail market: new vehicles replace existing cars even if they retain some useful life (as evidenced by the used car trade), not because the current stock of cars is determined by some authority to be inadequate in number or seating capacity, but because the new entries offer consumers a choice of lower cost, more reliability, greater safety, or other perceived attractions. Regulation, in an atmosphere of competition, will have to adjust to facilitate a healthy mix of embedded utility capacity, notably in the transmission and distribution area, and emerging non-utility sources that can bid against each other to serve consumers in the lowest cost, most efficient and environmentally sound manner. In this light, there can never be a glut of ways to improve service, improve air quality, and reduce consumers' bills.

New Jersey does not have to begin today to confront a saturated market for non-utility power sources, but the time for doing so could come even faster than in California, which has served the nation so well as a kind of energy laboratory. As a result, the BPU and the DOE, aided by the active participation of the emerging cogeneration industry and the existing utilities, must begin immediately to prepare for a regulatory regime which accurately mirrors the competitive forces now gathering. Therefore, no lid needs to be considered at this time and no moratorium on new cogeneration appears justifiable in the future, if we proceed to plan and prepare for a smooth transition to market-based energy policies in this vital area.

Miscellaneous Concerns

The duty to negotiate in good faith: While the provision of standard offer contracts and firm buy-back rates will do much to promote good faith bargaining by utilities, more protection may still be in order. Utilities may devise tactics or demands which discourage cogeneration. For example, JCP&L's demand that cogenerators sign a recapture clause would deny a cogeneration investor the current use of contracted for payments. (See Statement of Scott Spiewak at Tr. 55-56, September 20.) As such, it can only be described as a bad faith negotiating position. Other bad faith demands can be expected to be identified. To prevent these from holding up the contract process, the BPU and the DOE must maintain an open door policy for resolution of contract disputes. In particular, the BPU should have an expedited appeal process available to all cogenerators. This process would entitle any aggrieved party to petition the BPU for expedited disposition of a contract claim or an argument that a bargaining position is in bad faith. A list of such bad faith demands should be maintained and updated. Whenever a utility has been found to have negotiated in such a manner, penalties should be imposed on the utility and rewards allocated to the cogenerator which brought them to the attention of the BPU.

Maintaining Data on Cogeneration Development: Every cogenerator should file a registration statement with the DOE and the BPU simultaneous with its request for contract negotiations with a utility. The registration statement will require that the applicant identify the fuels to be used, and the size of the facility, as well as provide other relevant and potentially helpful information. With this process, it will be possible to monitor negotiations, review the milestones in each project, and determine whether any facility should lose its place in line for failure to proceed, while pushing other projects forward. A final registry of facilities will also help energy planners account for the full impact of cogeneration in the State, as it progresses from project inception to on-line facilities.

Utility Entry Into Cogeneration Marketing: With the growth in cogeneration, it is understandable that electric utilities should become interested in this source of power production. The risks to permitting such diversification are obvious. Utility-owned subsidiaries might receive more favorable treatment from their parent utilities, such as higher buy-back rates, easier negotiating, better credit and billing terms, and more favorable cancellation provisions. These fears have been realized in some states. In California, for example, San Diego Gas & Electric has been charged with agreeing to an energy-pricing formula for its subsidiary which exceeds the avoided cost offered to other cogenerators (

Cogen. Rept., November 8, 1985, p. 5). Clear conflicts of interest have been found where Southern California Edison personnel hold important positions in its wholly-owned cogeneration-subsidiary (*Id.*)

PURPA limits utility ownership in any qualifying facility to less than 50 percent of the equity in the project (18 *C.F.R.* 206). By implication, a utility, therefore, may invest up to that amount and still qualify as a cogenerator entitled to all the guarantees of a non-utility cogenerator. This policy creates incentives for utility management to favor their own subsidiaries, however arms-length the transactions might appear.

On the other hand, if utility shareholders can enjoy some of the benefits of a healthy cogeneration industry, their management will be more receptive to the concept in general and to specific projects in particular. Also, utility investment capital, customer relations and engineering abilities can be helpful in promoting the growth of this vital industry.

The Department believes that the State should offer conditional encouragement to the trend of utilities entering the cogeneration market. (PSE&G and JCP&L have already established such subsidiaries which are actively signing up projects.) Mindful of the risk of anti-competitive actions, however, the State must impose a higher level of scrutiny and special safeguards to all utility-subsidiary projects, at least until the independent cogeneration industry in the State has grown sufficiently to compete equally with utility-owned units. Thus, all contracts for large increments of cogeneration from utility-subsidiaries should be subject to a period of review by the BPU. Similarly, a policy of notice and protest should be offered in all such contracts, such that independents can protest to the BPU if they believe that they were squeezed out of a bid or were otherwise unfairly disadvantaged in efforts to sign up a customer. Should no problems develop in New Jersey over a reasonable period, then such procedures might be discontinued. But at least in the early going, New Jersey must profit from the experience in other states and take steps to see that this nascent industry is given the chance to flourish, while permitting proper opportunities for utilities to advance in this worthwhile direction.

Setting Cogeneration Quotas or Goals: One way to promote utility use of cogenerated power is to set quotas. Failure to achieve these goals could lead to penalties. The California PUC imposed a 1/7 of 1 percent penalty at the conclusion of its OII-26 investigation on the rate of return of PG&E for its failure to promote alternative energy contracts. The utility's response was dramatic with PG&E soon emerging as a national leader in the promotion of alternative and small-power energy sources (G. Maneatis, "The Nation's Leading Alternative Energy Utility: PG&E," 114 *Pub. Util. Fort.*, No. 13, Dec. 20, 1984, 18-22. For a history of this seminal case, see D. Roe, *Dynamos and Virgins*, Random House, 1985). New Jersey may need to have the option of imposing penalties for utility failure to promote cogeneration, to bargain in good faith, or otherwise to develop its full potential.

Incentives for small-power production: Many small cogeneration projects, namely units of 100 kilowatts or less, find it difficult to obtain needed financing due to the marginal economics of all small facilities. These include: capital costs which are high relative to labor, interconnection costs, fuel costs, and stand-by charges. Yet these small units offer great benefits to users and, in the aggregate, to society through their contribution to system reliability and economic development. They are most apt to be used by financially strapped customers, such as non-profit hospitals, YMCA's, schools, and other small to medium-size institutions. By reducing their costs of energy, small power production can enable them to provide greater services at lower costs to their clients and the community.

Accordingly, in order to facilitate their widespread use, the Department believes that units with a capacity of 100 kw or less should have the option of running their load meter backwards, rather than require them to sell their excess output to the utility. Any electricity sold to a utility would first be offset by a credit for purchases from the utility in a simultaneous "buy-sell" transaction, at the customer's request. All net energy sold to the utility would be billed at the retail rate applicable to the user.

SUMMARY AND RECOMMENDATIONS
ISSUES AND PROBLEMS
ACTIONS AND STRATEGIES

1. A STANDARD METHOD OF CALCULATING FAIR UTILITY BUY-BACK RATES IS NEEDED TO ENCOURAGE THE DEVELOPMENT OF COGENERATION.

[The rates offered by electric utilities for the purchase of cogenerated electricity are too low, too variable, and too unpredictable. In addition, these rates fail to satisfy the PURPA requirement to offer rates based upon the "full avoided cost" of cogeneration as a substitute for utility-owned and -operated power plants.]

THE BPU SHALL COMMENCE A PROCEEDING TO ESTABLISH RATES FOR COGENERATION BUY-BACK. THIS PROCEEDING SHALL BEGIN NOT LATER THAN 90 DAYS AFTER THE ADOPTION OF THIS PLAN AND SHALL CONCLUDE AS EXPEDITIOUSLY AS POSSIBLE, BUT IN NO CASE SHALL THE PROCEEDING LAST MORE THAN SIX MONTHS BEFORE A FINAL ORDER IS ISSUED. PROGRESS REPORTS SHALL BE PREPARED AND MADE PUBLIC EVERY 30 DAYS TO DETAIL ALL CRITICAL PATHS AND PROGRESS, ANY IMPEDIMENTS TO MAINTAINING THE HEARING SCHEDULE, AND SUCH OTHER INFORMATION AS THE DOE MAY REQUEST.

THIS PROCEEDING SHALL DETERMINE ALL ISSUES RELATING TO THE APPROPRIATE BUY-BACK RATE. FOR THE CAPACITY COMPONENT OF THE RATE, THE BPU WILL USE THE PROXY UNIT METHOD OF ANALYSIS, ASSUMING THE NEED FOR A NEW BASELOAD COAL-FIRED POWER PLANT, AS DESCRIBED HEREIN, BY 1992. FOR THE ENERGY COMPONENT, THE BPU SHALL DETERMINE THE RATE BASED UPON THE CURRENT RATE FOR OIL- OR GAS-GENERATED ELECTRICITY AT A BASELOAD FACILITY. THIS RATE SHALL APPLY FOR THE PERIOD OF 1986-1992, AT WHICH TIME THE PROXY UNIT'S FUEL COST WILL BE THE ENERGY COMPONENT INSTEAD.

THE BPU SHALL MAKE AVAILABLE FOR COGENERATORS RATES BASED UPON LONG-TERM, LEVELIZED PJM COST PROJECTIONS.

THE ELECTRIC UTILITIES SHALL FILE WITH THE DOE AND MAKE PUBLIC THEIR ESTIMATES OF PROJECTED PJM PURCHASE POWER RATES FOR THE NEXT 5-, 10- AND 15-YEAR PERIODS. A COGENERATOR SHALL HAVE THE OPTION OF SIGNING A CONTRACT WITH A UTILITY USING THESE ESTIMATES. HOWEVER, A COGENERATOR OR ANY OTHER PERSON MAY OBJECT TO THE ESTIMATES. THE BPU SHALL THEN COMMENCE A HEARING, WHICH SHALL BEGIN AND CONCLUDE AS EXPEDITIOUSLY AS POSSIBLE, BUT IN NO CASE SHALL LAST LONGER THAN 30 DAYS.

2. BACK-UP POWER RATES AND LACK OF ACCESS TO BACK-UP POWER DISCOURAGE INVESTMENT IN OTHERWISE FEASIBLE COGENERATION SYSTEMS.

[A 1981 BPU order allows the utilities to base their charges upon an assumed system outage rate of 15 percent, while experience indicates that the outage rate is closer to 5 percent. Gaining access to the utility system often involves problems such as long delays, lack of cooperation, unreasonable demands, and high costs to interconnect. In addition, a FERC decision has raised much doubt as to whether third-party cogenerators will have access to back-up power at any price.]

UPON REQUEST OF A COGENERATOR, EACH ELECTRIC UTILITY SHALL PROVIDE ALL NECESSARY FORMS OF BACK-UP POWER, INCLUDING BUT NOT LIMITED TO SUPPLEMENTARY POWER, BACK-UP POWER, MAINTENANCE POWER, AND INTERRUPTIBLE POWER. NO UTILITY MAY LIMIT THE OFFER OF OR ACCESS TO BACK-UP POWER TO ANY COGENERATOR OR ITS CUSTOMERS ON THE BASIS OF OWNERSHIP INTEREST OR FINANCING BASIS OF THE COGENERATION UNIT.

EACH UTILITY SHALL PUBLISH A GENERIC LIST OF COMPONENTS FOR INTERCONNECTION WHICH SHALL APPLY IN ALL CASES EXCEPT WHERE THE APPLICANT PRESENTS A CLEARLY DISTINCT PROPOSAL THAT MERITS INDIVIDUALIZED ATTENTION AND NEGOTIATION. THIS LIST SHALL BE SUBMITTED TO THE BPU WITHIN 30 DAYS OF THE ADOPTION OF THIS MASTER PLAN AND, UNLESS OBJECTED TO, SHALL CONSTITUTE THE STEPS REQUIRED FOR SUCCESSFUL INTERCONNECTION. IF OBJECTED TO, THE BPU SHALL PROMPTLY SCHEDULE AND COMPLETE A HEARING AND ISSUE A DETERMINATION NO LATER THAN 30 DAYS AFTER THE CONCLUSION OF THE HEARING. IF ANY UTILITY UNREASONABLY DELAYS OR OBSTRUCTS A COGENERATOR IN ITS EFFORTS TO OBTAIN INTERCONNECTION, THE BPU SHALL IMPOSE FINANCIAL PENALTIES TO BE AWARDED IN PART TO THE COGENERATOR BRINGING THE COMPLAINT.

THE RATES FOR SALES OF BACK-UP POWER SHALL NOT BE BASED UPON THE ASSUMPTION THAT FORCED OUTAGES OR OTHER REDUCTIONS IN ELECTRIC OUTPUT BY ALL COGENERATION FACILITIES ON AN ELECTRIC UTILITY'S SYSTEM WILL OCCUR SIMULTANEOUSLY, OR DURING THE SYSTEM PEAK, OR BOTH; AND SHALL TAKE INTO ACCOUNT THE EXTENT TO WHICH SCHEDULED OUTAGES OF THE COGENERATION FACILITIES CAN BE USEFULLY COORDINATED WITH SCHEDULED OUTAGES OF THE UTILITY'S FACILITIES. THE BPU SHALL REQUIRE UTILITIES TO SUBMIT STANDARD BACK-UP POWER RATES AS PART OF THE REQUIREMENT TO SUBMIT AND MAINTAIN STANDARD OFFER CONTRACTS.

EACH COGENERATION FACILITY SHALL BE OBLIGATED TO PAY ANY REASONABLE INTERCONNECTION COSTS WHICH THE BPU AUTHORIZES THE UTILITY TO CHARGE. NO RATE MAY EXCEED THE ACTUAL AND REASONABLE COST OF COMPLETING THE INTERCONNECTION, UNLESS A RETURN ON SAME IS AUTHORIZED BY THE BPU ON SIMILAR INTERCONNECTIONS FOR NON-COGENERATING CUSTOMERS. NO INTERCONNECTION FEE SHALL BE REQUIRED TO BE PAID IN ADVANCE. EACH COGENERATION FACILITY SHALL HAVE THE OPTION OF PAYING ITS INTERCONNECTION COSTS AS PART OF ITS REGULAR BILLING OR AS A DEDUCTION FROM BUY-BACK RATES. STANDARD BUY-BACK RATES AND TERMS SHALL BE INCLUDED IN EACH STANDARD OFFER CONTRACT.

3. COGENERATORS MUST HAVE ACCESS TO TRANSMISSION LINES TO WHEEL EXCESS ELECTRICITY AT REASONABLE RATES.

[Electric utilities maintain barriers, including unpredictable wheeling rates and non-economic restraints, to non-utility power sources who wish to gain access to transmission lines for the sale of cogenerated power to utilities in different service territories. In addition, cogenerators serving more than one facility need to engage in self-wheeling to take full advantage of economies of scale.]

IF A COGENERATION FACILITY AGREES, AN ELECTRIC UTILITY SERVING THE AREA WHEREIN THE FACILITY IS LOCATED SHALL TRANSMIT THE ENERGY OR CAPACITY OR BOTH TO ANY OTHER ELECTRIC UTILITY. IF THE UTILITY FAILS TO DO SO, UPON REQUEST THE UTILITY SHALL BE OBLIGATED TO PURCHASE THE POWER FOR USE IN ITS OWN SYSTEM AND SHALL PAY THE COGENERATION FACILITY AS IF IT HAD PERFORMED AS REQUESTED, UNLESS THE UTILITY SHOWS GOOD CAUSE FOR ITS REFUSAL TO WHEEL. GOOD CAUSE SHALL MEAN THE PHYSICAL OR ENGINEERING INABILITY TO TRANSMIT THE POWER DUE TO LACK OF TRANSMISSION CAPACITY, NOT INCLUDING A LACK OF CAPACITY CAUSED BY THE RESERVATION OF CAPACITY FOR UTILITY-GENERATED POWER NOT ON THE SYSTEM, TRANSMISSION OF POWER FROM OTHER UTILITIES OR WHEN A LACK OF CAPACITY SHOULD HAVE BEEN FORESEEN BY THE UTILITY DUE TO GROWTH ON THE SYSTEM.

WHERE UTILITY TRANSMISSION CAPACITY HAS BEEN FOUND BY THE BPU TO BE SATURATED, THE BPU SHALL ORDER THE UTILITY TO DEVELOP PLANS FOR THE EXPANSION OF CAPACITY IN THE MOST ENVIRONMENTALLY SOUND AND FISCALLY PRUDENT MANNER, BUT THE UTILITY SHALL NOT CHARGE COGENERATION FACILITIES MORE THAN THEIR FAIR SHARE OF NEW CAPACITY ON THE BASIS OF AN AUCTION AND BID SYSTEM IN WHICH UTILITY-SUPPLIED POWER SHALL HAVE NO ADVANTAGE OR PREFERENCE OVER POWER TO BE GENERATED BY A COGENERATION FACILITY.

ANY UTILITY TO WHICH SUCH ENERGY OR CAPACITY IS TRANSMITTED SHALL PURCHASE SAME AS IF THE COGENERATION FACILITY WERE SUPPLYING ENERGY OR CAPACITY DIRECTLY TO SUCH ELECTRIC UTILITY, EXCEPT THAT THE RATE FOR PURCHASE BY THE ELECTRIC UTILITY SHALL BE ADJUSTED UP OR DOWN TO REFLECT LINE LOSSES AND SHALL NOT INCLUDE ANY CHARGES FOR TRANSMISSION.

NO UTILITY SHALL CHARGE FOR LINE LOSSES DUE TO TRANSMISSION UNLESS THE UTILITY DEMONSTRATES THE ACTUAL INCIDENCE OF SAID LINE LOSSES ATTRIBUTED TO THE SPECIFIC COGENERATION FACILITY IN QUESTION.

NO UTILITY SHALL CHARGE FOR LINE LOSSES DUE TO TRANSMISSION IF THE COGENERATION FACILITY IS LOCATED WITHIN REASONABLE PROXIMITY OF LARGE LOAD DEMANDS ON THE UTILITY SYSTEM, DUE TO THE NEGATIVE NATURE OF SUCH LINE LOSSES.

NO UTILITY MAY CHARGE FOR LINE LOSSES UNLESS THE BPU APPROVES SAID CHARGES, AND IN NO CASE SHALL A COGENERATION FACILITY BE REQUIRED TO PAY FOR SUCH LOSSES IN ADVANCE OR WITHOUT THE OPTION TO PAY OVER A MUTUALLY AGREED PERIOD.

THE BPU SHALL ESTABLISH UNIFORM, STATEWIDE RATES FOR TRANSMISSION SERVICES WHICH SHALL BE INCLUDED IN STANDARD OFFER CONTRACTS AT THE OPTION OF THE COGENERATION FACILITY. SUCH RATES SHALL BE NON-DISCRIMINATORY AND NO GREATER THAN THE ACTUAL COST OF TRANSMISSION, TOGETHER WITH SUCH RETURN ON INVESTMENT AS THE BPU AUTHORIZES.

UPON REQUEST, EACH COGENERATION FACILITY SHALL BE ENTITLED TO TRANSMIT ITS POWER GENERATION OR ANY PORTION THEREOF TO AND AMONG ITS CUSTOMERS ON A NON-DISCRIMINATORY BASIS AT A RATE TO BE DETERMINED BY THE BPU.

4. THE USE OF STANDARD OFFER CONTRACTS CAN HELP TO EQUALIZE THE BARGAINING POWER OF UTILITIES AND COGENERATORS.

[Many factors contribute to the unfair bargaining advantages of utilities over cogenerators, including the monopsony position of the utility and the greater risk exposure of cogeneration investors. Steps must be taken to prevent utilities from taking advantage of their monopsony status.]

THE BPU SHALL REQUIRE EACH ELECTRIC UTILITY TO PREPARE STANDARD OFFER CONTRACTS WITHIN 30 DAYS OF THE ADOPTION OF THIS MASTER PLAN. EACH CONTRACT SHALL ADDRESS AT A MINIMUM ALL THE REQUIREMENTS PRESENTED IN THIS PLAN AS SUITABLE FOR CONTRACT OFFERS AND SUCH OTHER REQUIREMENTS AS THE BPU OR THE DOE SHALL, FROM TIME TO TIME, REQUIRE TO BE INCLUDED.

A STANDARD OFFER CONTRACT IS AN OFFER TO ENTER INTO A CONTRACT WITH ANY QUALIFIED COGENERATION FACILITY. IT SHALL INCLUDE ALL ESSENTIAL TERMS REQUIRED OF THE UTILITY AND THE COGENERATION FACILITY AND ENTITLES THE FACILITY TO ACCEPT THE TERMS OF THE CONTRACT ON ITS FACE OR TO NEGOTIATE ANY CHANGES, ADDITIONS, OR DELETIONS IT WISHES. UPON SIGNING THE CONTRACT AND FILING A CERTIFIED COPY WITH THE UTILITY, THE BPU AND THE DOE, THE CONTRACT SHALL BE BINDING ON THE SIGNATORY AND THE UTILITY.

ANY COGENERATION FACILITY SHALL BE ENTITLED TO ACCEPT THE STANDARD OFFER CONTRACT PRESENTED TO THE BPU OR IT MAY PROTEST THE TERMS, CONDITIONS OR ANY LANGUAGE IN THE CONTRACT OFFER AND REQUEST A HEARING WITH THE BPU, WHICH THE BPU SHALL COMMENCE AND COMPLETE AS SOON AS POSSIBLE, NOT TO EXCEED SIX MONTHS. AT THE CONCLUSION OF THIS HEARING, THE BPU SHALL REQUIRE WHATEVER CHANGES, ADDITIONS OR DELETIONS NECESSARY TO ACHIEVE THE PURPOSES OF THIS MASTER PLAN. THE STANDARD OFFER AS APPROVED OR MODIFIED SHALL THEN OPERATE AS A BINDING LEGAL INSTRUMENT IN THE SAME MANNER AS A STANDARD OFFER CONTRACT SUBMITTED BY THE UTILITY AND SUBJECT TO ACCEPTANCE BY A QUALIFIED COGENERATION FACILITY.

5. COGENERATORS NEED ACCESS TO ADEQUATE, AFFORDABLE SUPPLIES OF NATURAL GAS

[Natural gas is the principal fuel of cogeneration and, due to its clean-burning properties, the fuel of choice in urban and densely populated areas. Prospective cogenerators often have difficulty in securing supplies at affordable prices.]

THE BPU SHALL REQUIRE EACH NATURAL GAS UTILITY (LOCAL DISTRIBUTION COMPANY OR LDC) TO OFFER TO PROVIDE NATURAL GAS TO ANY COGENERATION FACILITY AS THE PRIMARY FUEL FOR THE FACILITY IN SUCH QUANTITIES AND QUALITY NECESSARY FOR SUCCESSFUL COGENERATION. WITHIN 30 DAYS OF THE ADOPTION OF THIS PLAN, EACH LDC SHALL ALSO PREPARE AND SUBMIT PLANS TO THE BPU AND THE DOE WHICH SHALL DETAIL THE AMOUNTS, QUALITY AND RATES TO BE CHARGED FOR NATURAL GAS FOR COGENERATION, ANY SERVICE EXTENSIONS NECESSARY, AND ANY RESTRICTION OR CONDITIONS ON THE RECEIPT OF SUCH SERVICES.

RATES FOR TARIFFS FOR NATURAL GAS FOR COGENERATION SHALL BE NO HIGHER THAN THOSE FOR NATURAL GAS SOLD BY THE LDC TO SIMILARLY SITUATED CUSTOMERS, EXCEPT THAT SOME CREDIT SHOULD BE ACCORDED COGENERATORS IN LIGHT OF THE EXTERNAL BENEFITS CONFERRED BY COGENERATION.

6. IN ORDER TO ENCOURAGE COGENERATION, THE PROCESS OF OBTAINING ENVIRONMENTAL PERMITS MUST BE EXPEDITED.

[Cogeneration developers have had difficulty in gaining the necessary environmental permits from the Department of Environmental Protection. They also fear the exaction of unreasonable air pollution requirements that may make cogeneration uneconomic.]

THE DEP SHALL ESTABLISH A PROCEDURE FOR THE PROMPT AND FAIR RESOLUTION OF ALL PERMIT REQUIREMENTS FOR COGENERATION APPLICANTS WITHIN A SINGLE OR INTEGRATED PERMIT PROCESS.

DUE TO THE POTENTIAL NET REDUCTIONS IN VARIOUS AIR POLLUTANTS IN NEW JERSEY FROM THE WIDESPREAD USE OF COGENERATION TO SUBSTITUTE FOR UTILITY POWER GENERATION AND PURCHASES, THE DEP SHALL DEVISE AN OFFSETS STRATEGY WHEREBY POLLUTANTS EMITTED AT THE LOCAL LEVEL FROM A COGENERATION FACILITY MAY BE OFFSET FROM NET REDUCTIONS IN POLLUTANTS ENTERING THE SAME GENERAL AREA.

THE DEP SHALL DEVISE AND EMPLOY METHODS FOR DETERMINING THE AGGREGATE AIR QUALITY IMPACTS OF VARIOUS LEVELS AND TYPES OF COGENERATION USAGE AS AN ALTERNATIVE OR SUPPLEMENT, IN WHOLE OR IN PART, TO REQUIRING INDIVIDUALIZED AIR QUALITY REVIEWS FOR EACH COGENERATION APPLICANT.

7. THE GROWTH OF COGENERATION MAY BE STIFLED BY THE CONTINUING AND, IN SOME CASES, GROWING GLUT OF UNECONOMIC BUT UTILITY-OWNED ELECTRIC POWER GENERATING CAPACITY.

[As more customers generate their own power and sell back to the utility, fewer customers will be left to pay the fixed costs of the utility. The utility will then raise rates to remaining customers, leading to still more customers leaving the system, cogenerating their own power, or simply increasing conservation. Restricting the amount of new capacity from other sources is at best a short-term solution that would impose substantial hidden costs on the public.]

EACH COGENERATION SPONSOR SHALL FILE WITH THE DOE A CONFORMING COPY OF ITS APPLICATION TO BE CERTIFIED AS A QUALIFYING FACILITY PURSUANT TO FERC REGULATIONS, 18 *C.F.R.* 292.203 AND .207, AT THE SAME TIME THAT IT FILES FOR SAME WITH FERC. THE DOE SHALL THEN MAINTAIN AN OPEN REGISTER OF "QF" APPLICATIONS AND ALL UPDATES AS

PROVIDED BELOW. EACH COGENERATOR SHALL THEN FILE WITH THE DOE AT LEAST ONCE EVERY SIX MONTHS, OR MORE OFTEN IF SO ORDERED. A REPORT SETTING FORTH THE FOLLOWING:

A. A LIST OF CRITICAL MILESTONES IN THE DEVELOPMENT OF THE COGENERATION PROJECT, ESTIMATED DATES FOR ACHIEVING THOSE CRITICAL POINTS AND ANY IMPEDIMENTS AND PLANS FOR MEETING SAME.

B. THE STATUS OF THE COGENERATION PROJECT IN MEETING THE MILESTONES IDENTIFIED IN ITS PRIOR REPORT OR AS THEY MAY BECOME KNOWN:

C. THE STATUS OF THE PROJECT WITH THE DEP AND ANY OTHER FEDERAL, STATE OR LOCAL AGENCY WHICH REQUIRES PERMITS TO CONSTRUCT OR OPERATE THE FACILITY;

D. THE STATUS OF THE COGENERATION PROJECT IN ITS CONTRACT DEALING WITH ANY ELECTRIC UTILITY REGARDING BUY-BACK RATES, INTERCONNECTION, BACK-UP POWER, WHEELING, NATURAL GAS, OR ANY OTHER RELEVANT NEGOTIATION ISSUE INVOLVING REGULATED UTILITIES IN NEW JERSEY;

E. A CONFORMING COPY OF THE CONTRACT(S) WITH THE ELECTRIC UTILITY(IES) AT THE TIME IT IS SIGNED AND FINALIZED;

F. A NOTARIZED STATEMENT FROM THE PROJECT SPONSOR WITHIN 24 HOURS OF THE DATE THAT (1) CONSTRUCTION HAS BEGUN ON THE FACILITY, (2) WHEN CONSTRUCTION HAS BEEN COMPLETED, AND (3) WHEN THE FACILITY HAS BEEN BROUGHT INTO OPERATION;

G. A REPORT OF THE FACILITY'S OPERATING RECORD AT THE CONCLUSION OF EACH CALENDAR YEAR, NOTING ANY CHANGES IN HEAT RATE, FUEL USE, SIZE, EFFICIENCY, OUTAGES, OR OTHER RELEVANT INFORMATION.

AT LEAST ANNUALLY THE DOE SHALL PUBLISH A STATUS REPORT ON COGENERATION IN NEW JERSEY WHICH SHALL INCLUDE, BUT NEED NOT BE LIMITED TO, A SUMMARY OF THE PRIOR DATA AND SHALL PROMINENTLY SET FORTH A STATEMENT AS TO THE AMOUNTS OF COGENERATION PLANNED, CERTIFIED WITH FERC, UNDER CONTRACT, UNDER CONSTRUCTION, AND IN OPERATION.

ANY COGENERATION PROJECT OF 100 MW OR LARGER SHALL BE DESIGNATED AND CONSIDERED TO BE AN "ENERGY FACILITY" PURSUANT TO THE DEPARTMENT OF ENERGY ACT, *N.J.S.A.* 52:27F-15(c), AND THEREFORE SHALL REQUIRE A FINDING OF NEED AND CONFORMANCE WITH THE APPROVED ENERGY FORECAST AND RESOURCE PLAN OF THE AFFECTED UTILITY(IES), PURSUANT TO THE REQUIREMENTS OF *N.J.A.C.* 14A:20-1.1, *ET SEQ.*, AND THE ENERGY FACILITY REVIEW POLICIES OF THE DEPARTMENT.

WITHIN SIX MONTHS OF THE ADOPTION OF THIS MASTER PLAN, EACH ELECTRIC POWER UTILITY SHALL SUBMIT A PLAN TO THE DOE AND TO THE BPU FOR ACHIEVING A REALISTIC MARKET FOR POWER COMPETITION BETWEEN AND AMONG UTILITY FACILITIES AND NON-UTILITY FACILITIES, INCLUDING METHODS FOR COMPARING THE DIRECT AND INDIRECT COSTS OF POWER GENERATION, SYSTEM EFFICIENCY AND RELIABILITY AND ENVIRONMENTAL IMPACTS. THE PLAN WILL DESCRIBE METHODS FOR AUCTIONING RIGHTS TO SELL POWER TO THE UTILITY ON A NON-DISCRIMINATORY BASIS. UTILITY FACILITIES AND NON-UTILITY SOURCES WILL HAVE EQUAL OPPORTUNITY TO COMPETE FOR THE OPPORTUNITY TO GENERATE AND MARKET ELECTRICITY, IN ORDER TO FURTHER THE GOALS OF A LEAST-COST ENERGY STRATEGY FOR RATEPAYERS. WITHIN 30 DAYS OF RECEIPT OF THE PLANS, THE DOE AND THE BPU SHALL SET FORTH DATES FOR HEARINGS TO CONSIDER SUCH PLANS AND DETERMINE HOW BEST TO PROMOTE COMPETITION AND LEAST-COST DELIVERY OF RELIABLE, ENVIRONMENTALLY SOUND SERVICE. THESE HEARINGS SHALL BE COMPLETED WITH AN ORDER ISSUED SETTING FORTH SUCH STRUCTURE OF A MARKET FOR POWER SOURCES WITHIN ONE YEAR OF THE ADOPTION OF THIS PLAN.

8. COGENERATORS MUST BE PROTECTED FROM BAD FAITH DEMANDS AND BARGAINING

[Evidence indicates that utilities do not always bargain in good faith. While standard offer contracts and firm buy-back rates will promote good faith bargaining, more protection may be needed.]

NO UTILITY MAY REQUIRE AS A CONDITION OF ANY CONTRACT THAT THE COGENERATION FACILITY AGREE TO A RECAPTURE CLAUSE OR ANY OTHER ARRANGEMENT WHICH WILL DENY TO THE FACILITY AND ITS INVESTORS THE IMMEDIATE USE OF ALL PAYMENTS FOR THE SALE OF CAPACITY OR ENERGY.

EACH UTILITY SHALL NEGOTIATE IN GOOD FAITH AT ALL TIMES WITH ANY COGENERATION OWNER, OPERATOR OR SPONSOR AND SHALL ENDEAVOR TO REACH AN AGREEMENT IN THE SHORTEST POSSIBLE TIME.

THE BFU SHALL ESTABLISH AN ABBREVIATED PROCESS FOR THE HEARING OF COMPLAINTS, PROTESTS OR PETITIONS FOR DECLARATORY RULINGS ON BAD FAITH ACTIVITIES OR NEGOTIATING POSITIONS. UPON SUCH A FIND, THE BPU SHALL ORDER THE UTILITY TO CEASE AND DESIST FROM SUCH BAD FAITH ACTION, AND IT SHALL ORDER THE UTILITY TO PAY OR CREDIT TO THE COGENERATION PROJECT A SUM EQUAL TO ALL COSTS ATTRIBUTABLE, DIRECTLY OR INDIRECTLY, TO SUCH BAD FAITH ACTIONS.

THE BPU SHALL DEVISE, DEVELOP AND MAINTAIN A CURRENT LIST OF BAD FAITH PRACTICES, WHETHER PRESUMPTIVELY OR PER SE BAD FAITH, AND IT SHALL ENTERTAIN PETITION FOR DECLARATORY RULINGS WITH RESPECT TO ANY PRACTICE WHICH THE PETITIONER BELIEVES SHOULD BE ADDED TO OR REMOVED FROM THE LIST. SUCH PRACTICES SHALL INCLUDE, BUT NOT BE LIMITED TO, INJECTING BAD FAITH DEMANDS INTO THE NEGOTIATION PROCESS, HABITUALLY OR REPEATEDLY FAILING TO MEET REASONABLE REQUESTS FROM A POTENTIAL COGENERATOR FOR MEETINGS, ANSWERS OR DECISIONS, OR FAILING TO BRING TO MEETINGS REPRESENTATIVES KNOWLEDGEABLE ABOUT THE PARTICULARS OF THE COGENERATION PROJECT AND QUALIFIED TO RENDER DECISIONS THAT BIND THE UTILITY IN THE MANNER OF A BUSINESS AGENT. A UTILITY DEEMED TO BE ENGAGING IN SUCH BAD FAITH NEGOTIATION SHALL BE LIABLE TO THE COGENERATOR FOR ALL COSTS PROXIMATELY CAUSED BY SUCH BAD FAITH NEGOTIATION OR DEMANDS, AS DETERMINED BY THE BPU.

9. COGENERATORS MUST HAVE THE OPPORTUNITY TO PROVIDE LEAST-COST ENERGY FOR CONSUMERS.

[Cogenerators have not in the past been able to displace utility-generated capacity, even though the power generated from these sources is more expensive.]

IF A UTILITY REFUSES TO CONTRACT FOR CAPACITY OR ENERGY OR BOTH FROM AN OTHERWISE QUALIFIED COGENERATION FACILITY DUE TO A LACK OF NEED FOR THE POWER, AND IF NO OTHER PURCHASER OF THE POWER IS FOUND BY THE UTILITY WHICH WILL PURCHASE POWER TRANSMITTED TO IT, THE COGENERATION FACILITY MAY BID AGAINST POWER SUPPLIED BY UTILITY-OWNED AND -OPERATED FACILITIES OR OTHER NON-UTILITY PROJECTS. THE UTILITY SHALL SELECT THE POWER SOURCE WHICH AVOIDS THE GREATEST COST OTHERWISE INCURRED BY THE RATEPAYERS OF THE UTILITY. IF THE COGENERATOR IS AGGRIEVED BY THE DECISION OF THE UTILITY, IT MAY PETITION THE BPU FOR A DECLARATORY RULING THAT THE UTILITY SHOULD PURCHASE THE POWER OFFERED BY THE COGENERATOR UPON A FINDING THAT (1) THE POWER THAT WOULD BE DISPLACED COSTS MORE TO PRODUCE OR SUPPLY THAN THE POWER FROM THE COGENERATOR, WHETHER CAPACITY OR ENERGY OR BOTH; AND (2) THE COGENERATOR OFFERS NON-ECONOMIC BENEFITS, SUCH AS ENHANCED SYSTEM RELIABILITY, THE BURNING OF ALTERNATIVE FUELS, THE REDUCTION OF AIR OR WATER POLLUTION OR OTHER ADVANTAGES SUPERIOR TO THOSE FROM THE UTILITY FACILITY OR OTHER NON-UTILITY FACILITIES ON THE SYSTEM.

THE BPU AND THE DOE SHALL REQUIRE ELECTRIC UTILITIES TO PURCHASE FROM COGENERATORS POWER (CAPACITY OR ENERGY OR BOTH) WHICH IS LESS COSTLY TO RATEPAYERS THAN UTILITY-OWNED OR -OPERATED CAPACITY EXCESS, REGARDLESS OF WHETHER SUCH UTILITY CAPACITY IS IN RATE BASE, WHENEVER THE NON-UTILITY SOURCE WOULD CONFORM TO OR OTHERWISE PROMOTE A LEAST-COST ENERGY STRATEGY. IN MAKING THIS FINDING, THE BPU SHALL FIND THAT THE NON-UTILITY SOURCES PROMOTE A LEAST-COST ENERGY STRATEGY WHENEVER SAID COGENERATION FACILITIES OR INCREMENTS CAN DISPLACE COSTLIER UTILITY FACILITIES. THE BPU SHALL THEN PROCEED TO DETERMINE WHETHER SAID CAPACITY WHICH IS DISPLACED SHOULD BE REMOVED FROM RATE BASE AS NO LONGER USED AND USEFUL.

10. SMALL COGENERATION FACILITIES MUST BE PROTECTED FROM UNFAIR COMPETITION FROM UTILITIES THAT ENTER THE COGENERATION MARKET.

[Utilities are beginning to enter the market for cogeneration development; however, special safeguards are needed to protect competition.]

ANY COGENERATION FACILITY OF 100 KW OR LESS SHALL BE CONSIDERED A "SMALL POWER PRODUCTION FACILITY."

THE BPU SHALL REVISE ITS COGENERATION AND SMALL POWER PRODUCTION TARIFF/RIDER QFS (MARCH 21, 1985, DOCKET NO. 8412-1239) TO IMPLEMENT THE OPTION OF NET ENERGY BILLING AT A RATE EQUAL TO THE UTILITY'S EFFECTIVE RETAIL RATE FOR THE CUSTOMER, WHICH SHALL APPLY FOR ANY SMALL POWER PRODUCTION FACILITY.

THE BPU SHALL REVIEW EACH CONTRACT FOR CAPACITY, ENERGY OR BOTH FOR ANY COGENERATION FACILITY OF 1 MW OR GREATER THAT IS FINANCED OR OWNED IN PART BY THE SUBSIDIARY OF AN ELECTRIC UTILITY. THE BPU SHALL DETERMINE WHETHER THE UTILITY OFFERED ANY PREFERENCE TO THE PROJECT THAT IS NOT AVAILABLE TO NON-UTILITY UNITS, AND SHALL, IF IT SO FINDS, DISAPPROVE OF SAME OR IMPOSE SUCH NEW STANDARDS AS IT FINDS APPROPRIATE.

THE BPU SHALL PROVIDE 30 DAYS FOR ANY PERSON TO PROTEST THE AWARDING OF ANY CONTRACT TO ANY COGENERATION FACILITY THAT IS FINANCED OR CONSTRUCTED IN WHOLE OR PART BY A UTILITY SUBSIDIARY.