WATER ELECTRIC FORT PIERCE UTILITIES AUTHORITY GAS SEWER

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August 28, 1990

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Florida Department of Environmental Regulation
2600 Blairstone Road
Tallahassee, Florida 32399

Attention: Mr. Barry Andrews

Dear Mr. Andrews:

REFERENCE AIR PERMITS: Unit #6 - AO-56-113534
Unit #7 - AO-56-112679
Unit #8 - AO-56-112678
Unit #9 - AO-56-175955

In accordance with our meeting with you on July 24, 1990 and subsequent discussions, we are submitting six(6) copies of the Prevention of Significant Deterioration (PSD) Application for our H. D. King Unit 9. We have also enclosed one paper copy and one disk copy of the computer modeling runs.

A check in the amount of $5,000 is enclosed for the required application fee.

If you have any questions regarding the application or supporting data, please feel free to call Mr. Steve Day of Black & Veatch at (913) 339-2880.

Sincerely,

Harry Schindehette, P.E.
Director of Utilities

jbm
Enclosure

cc: Jack Miller
Steve Day
Harry Lamb
M. Harley
C. Halladay
B. Andrews
G. Harper EPA
L. Brooks, SE Dist

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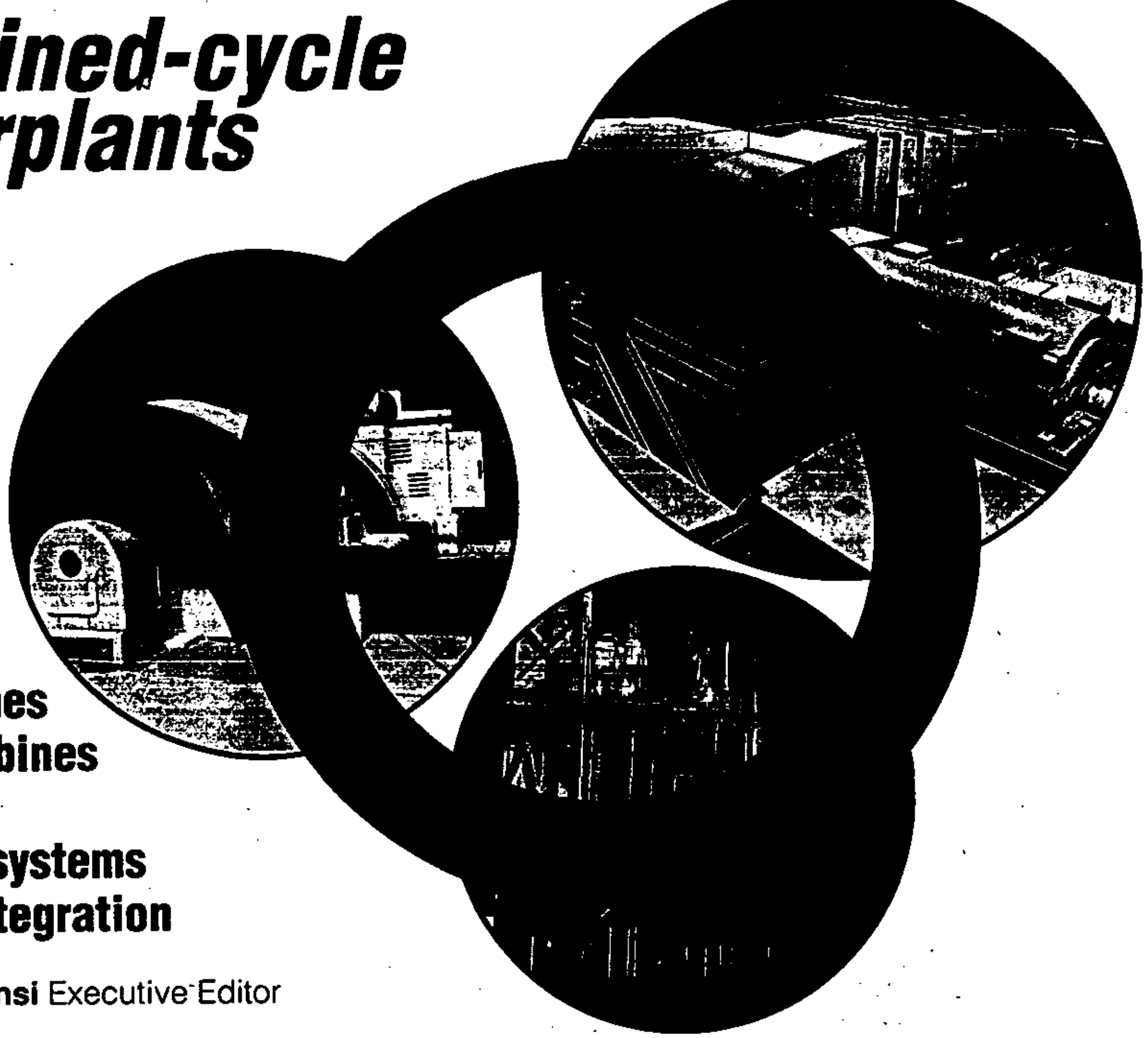
Combined-cycle powerplants



- **Gas turbines**
- **Steam turbines**
- **HRSGs**
- **Auxiliary systems**
- **System integration**

By **Jason Makansi** Executive Editor

[redacted] than competing nuclear and conventional fossil-fired steam/electric stations. [redacted] are other traditional advantages long held by the combined cycle (Figs 1, 2).

To these must be added several advantages that have appeared more recently. [redacted] as similar programs for boilers and steam turbines either stagnated, reverted to government sponsorship, or focused on problems with existing units. [redacted] stations.

Unlike conventional steam turbines, gas turbines come in specific sizes. But the range of sizes has expanded—at both ends—in the last few years. [redacted] largest machines can deliver 40% more power today than they could only five years ago. These high-output units are expected to better serve the needs of utilities and independent power producers. Strong interest in cogeneration prompted turbine manufacturers also to focus on the 500-kW to 10-MW market, the segment traditionally served by engine/generators.

The application range of combined cycles has also expanded. Cogeneration, especially projects based largely on the sale of electric power to utilities, is a good match for combined cycles because it can offer maximum power generation at the expense of thermal output. Several aircraft-derivative-type gas turbines in the 10-60-MW range and heavy-duty types previously popular for industrial applications, such as for offshore platforms, anchored many of the cogeneration plants built in the 1980s (see box, p 110).

Combined cycles also can be retrofitted to existing powerplants (see box, p 122). Adding an HRSG and steam turbine converts a peaking gas turbine into a unit more suitable for intermediate- or base-load duty, or just into a more efficient system. Adding a gas turbine to a fossil-fired boiler in place of the forced-draft fan, also called a turbocharged boiler scheme, can improve efficiency and raise capacity. This scheme is not yet popular in the US, although it has been applied at several sites in Europe.

Existing steam turbines can also be repowered by adding a new gas turbine and HRSG, and retiring the boiler. Finally, at least one unfinished nuclear powerplant was successfully converted to a combined cycle (Fig 3) and several others are under consideration.

However, the primary driving force behind the combined-cycle market has little to do with technology or applications. The presence of the so-called worldwide "gas bubble" deflated prices from their late 1970s levels concurrent with a similar supply/demand/price scenario for petroleum. But most industry observers think that the era of inexpensive premium fuels has about had its day.

Thus, solid-fuel compatibility, perhaps more than anything else, has led to the great expectations for combined cycles in the coming years; indeed, the specter of surges in premium-fuel prices has always been held over the head of the potential combined-cycle user. For one thing, the possibility of making gas turbines compatible with coal helped convince bureaucrats in Washington to essentially repeal the 1978 Fuel Use Act in 1987.

Even though technologies such as coal gasification and pressurized fluidized-bed combustion (see box, p 118) are just now being commercially demonstrated, plant owners gain more confidence in the long-term economics knowing that a premium-fuel-fired gas turbine can later be converted to a coal-based combined cycle if needed. Of course, a simple-cycle gas turbine can be converted to combined cycle without coal.

Gas turbines

The combined cycle is anchored by the gas turbine. In fact, for the most part, advances in gas-turbine technology are responsible for performance gains with combined cycles.

Gas turbines are fundamentally classified as light or aircraft-derivative and industrial. Distinctions are blurring as each borrows technology from the other. To illustrate: Designers of aeroderivative units for cogeneration service have borrowed industrial features. Meanwhile, many of the performance gains achieved by heavy-duty units can be attributed to materials and design advances with the aeros.

Higher firing temperatures in both boost efficiency without appreciably increasing their size. The new class of 150-MW machines (Figs 4, 5) exhibit turbine inlet temperatures of around 2300F. Combined-cycle plants based on these units are expected to show heat rates below 7000 Btu/kWh and fuel-to-power efficiencies of 50% and above when firing premium fuels.

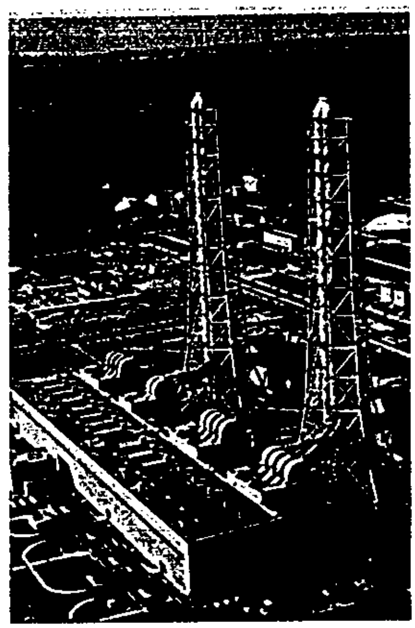
Such high temperatures can be accommodated only by extensive design changes to the conventional hot-gas path. The first several stages of blading are generally constructed of high-strength alloys and/or are coated with special materials for corrosion and oxidation resistance. Internal and external air-cooling circuits also are required for the first few stages of blades and for stationary nozzles. Cooling air is typically drawn from the compressor discharge or from individual compressor stages. In some cases, an intercooler is used if the temperature of the compressor discharge is too high to provide effective cooling of the blading and hot-gas-path components.

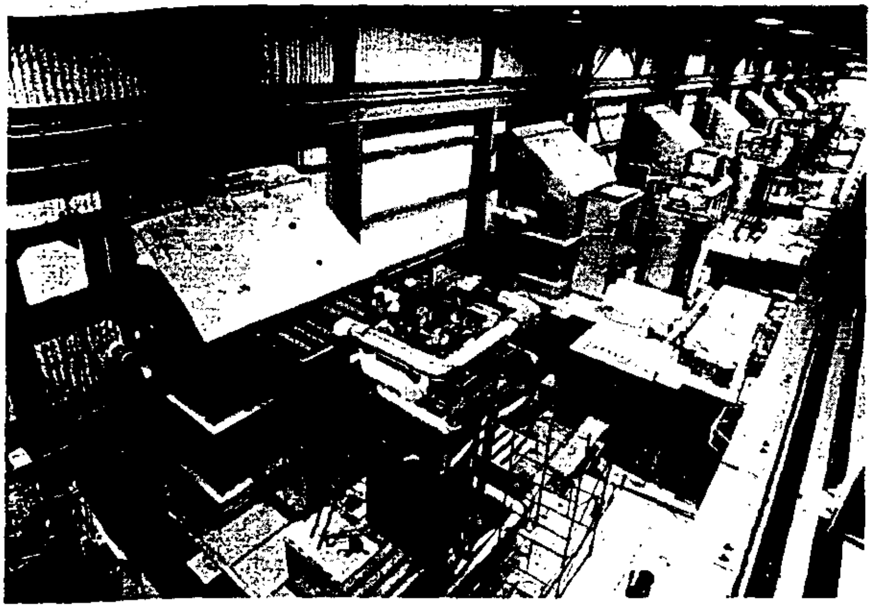
Another basic gas-turbine descriptor, like the turbine inlet temperature, is the pressure ratio. The pressure ratio at which the gas-turbine thermal efficiency is greatest is different from that at which the specific power output (a term denoting output in megawatts divided by mass flow through the unit) is greatest. Therefore, for a given turbine inlet temperature, the combined-cycle thermal efficiency must be optimized around the pressure ratio where the specific power output of the gas turbine is greatest. This presents a dilemma for turbine designers because it is not easy to change the pressure ratio for a given machine model. Pressure ratios for today's large machines are around 14:1.

An obvious consequence of the higher firing temperature is a correspondingly higher turbine exhaust temperature—typically 950F to 1050F. This adds to the options available for combined cycles. For one, steam bottoming cycles with reheat make more sense. For another, supplementary firing of the exhaust can be avoid-

1. Largest gas turbine in US repowers steam turbine at powerplant in Virginia (left)

2. World's largest facility, in Japan, includes 14 gas turbine/HRSG modules





3. Largest combined cycle for cogeneration service features 12 85-MW gas-turbine/HRSG modules supplying steam to one 365-MW steam turbine

ed. Similarly, the high compression ratios lead to higher temperatures in the compressor discharge, a source of heat for such steam-side duties as preheating feedwater should it be desirable to further integrate the gas and steam cycles.

On the other hand, high firing temperatures confound efforts to limit NO_x and CO emissions from the gas turbine. Water/steam injection is a popular way to minimize NO_x emissions. Recall that adding water or steam in the combustion zone lowers the flame and gas temperature, and suppresses NO_x formation by up to 70%. Steam injection appears to be favored today, especially for combined-cycle installations. Though it takes 50% more steam on a mass basis to obtain equivalent reduction, it is thought by some to pose lower potential for damage to critical turbine components and does not penalize the heat rate as much to make up for the heat of vaporization lost when water is injected.

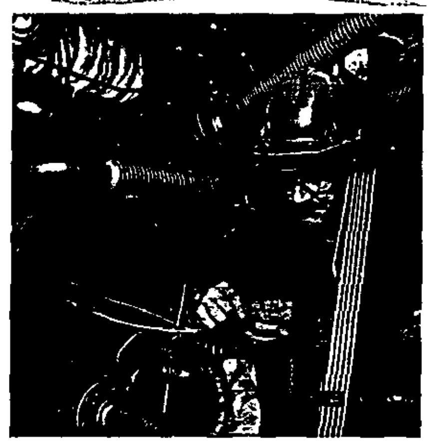
To continue reducing emissions in the face of higher firing temperatures, virtually all of the major vendors have or are developing some form of multiple combustor arrangement employing staged combustion (Fig 6). Key factors are adequate premixing of air and fuel upstream of the combustor and stable control of fuel and air as the system transfers from one burner stage to another.

One approach is use of a mechanical shutter to distribute air between the combustion and dilution zones so that the combustor burns fuel at near-stoichiometric conditions at all times. Another concept is to employ a set of mini-burners fired according to a predetermined sequence instead of the single burner used in older units. Finally, one supplier replaced a single fuel nozzle on the combustor can with six nozzles mounted so that additional piping is not required. In addition to reducing NO_x emissions, this significantly reduces noise, shortens flame length, and extends the period between overhauls.

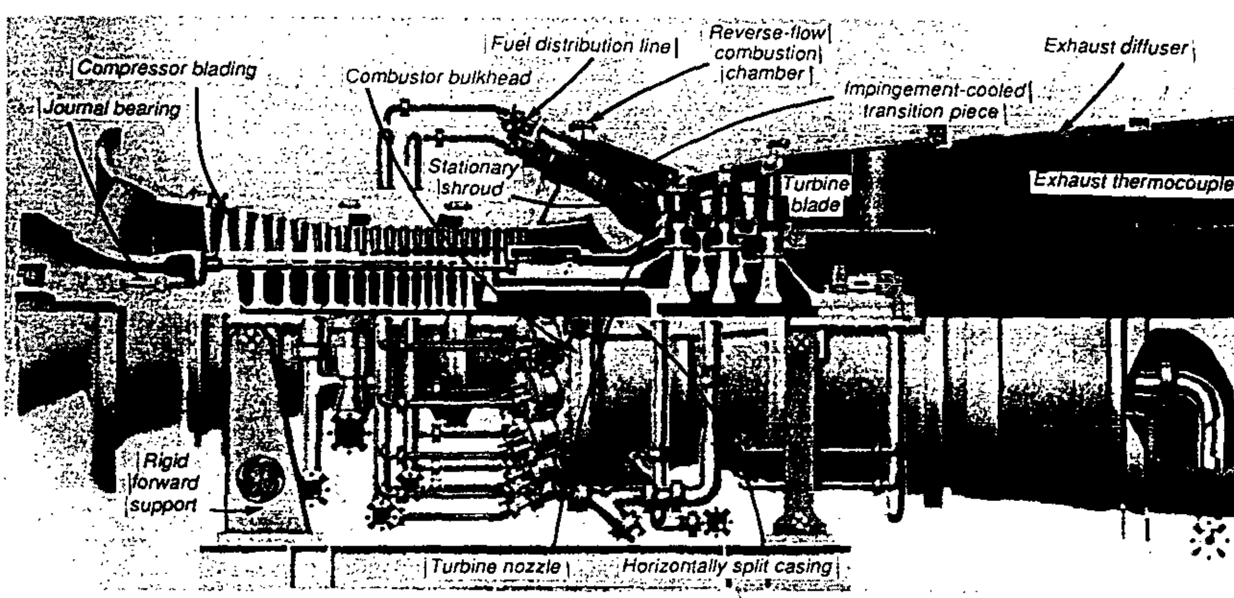
In general, today's combustors can achieve NO_x emissions levels of between 30 and 70 ppm at 15% excess O_2.

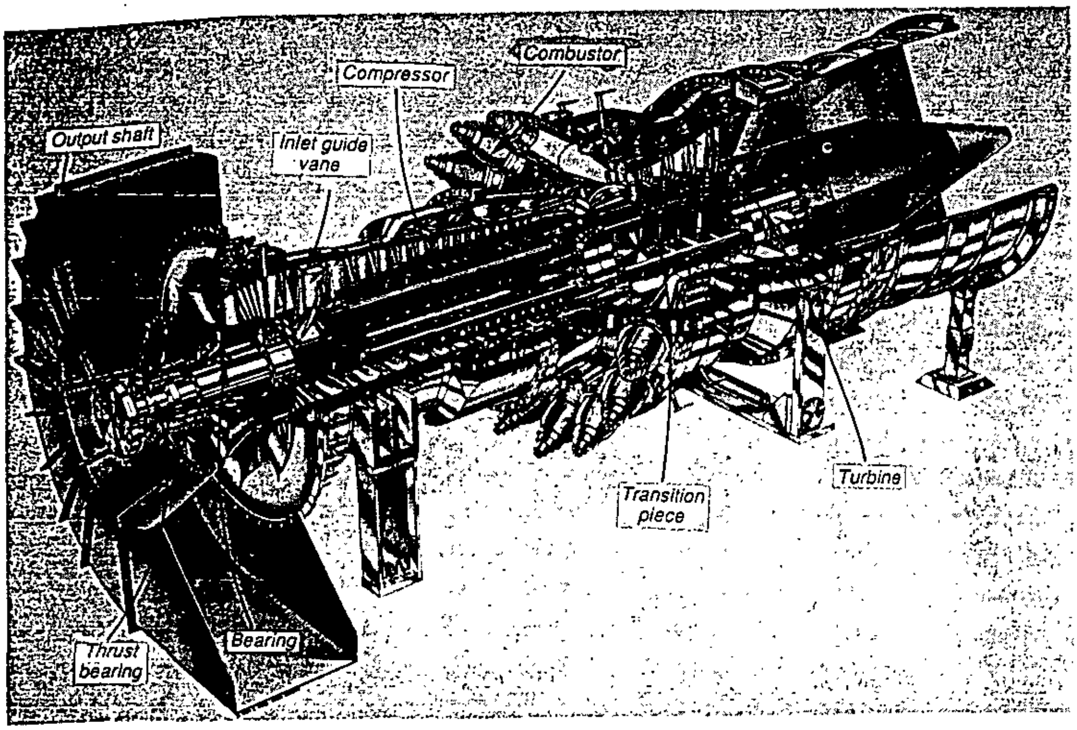
Small-machine advances

Though advances in large machines are taking center stage today, don't overlook what's happening with small units, especially the movement of machines from the



4. Gas turbines of nominal 150-MW size have inlet temperatures of about 2300F, fuel-to-power efficiencies of 50% and above in combined cycle





5. **Advanced cooling** techniques and high-strength thermally resistant alloys are required for large gas turbines to handle the high firing temperatures

aircraft industry to the power industry (Fig 7). In the most recent example, the industrial application features a turbine with the same inlet temperature as the previous-model aeroderivative but benefits from higher efficiency in the high-pressure compressor and high-pressure (h-p) turbine and the low-pressure turbine/power turbine.

Simple cycle, the machine has an efficiency close to five percentage points higher than previously, with an output of 40 MW or higher, depending on whether steam or water is injected into the combustor for NO_x control. In a combined-cycle configuration, output is expected to top 50 MW with net thermal efficiency of close to 52% when fired by natural gas.

Another concept being investigated by several manufacturers is an intercooled version of a recuperative gas turbine. In one configuration, an intercooler is placed between the existing two-stage centrifugal compressor. The intercooler circulates an ethylene glycol/water mixture which picks up the heat of compression. It is said to lower fuel consumption by over 25% and increase power output by 40% compared to a machine without reheat.

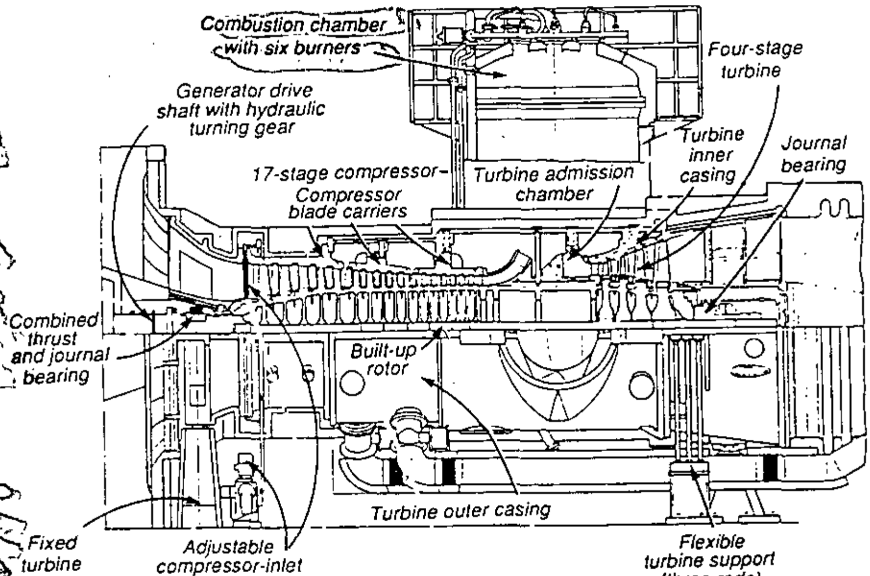
Year 2000 machines

With the worldwide market active, gas-turbine technology continues to advance at a rapid pace. Within 10 years, turbine inlet temperatures are expected to be around 2500F, pressure ratios around 16:1; also the largest units will produce more than 200 MW and offer combined-cycle efficiencies near 60%.

To reach this point while continuing to reduce emissions, further improvements in combustion technology must ensue. An example is the double-cone premix burner (Fig 8). Primary air enters the cone via the longitudinal slots that form between the two half-cones. The parallel cones contain a series of small orifices through which the gaseous fuel enters the conical plenum. Liquid fuel can be injected via an atomizing nozzle at the apex of the burner. Main feature of this design is that there is no separation between premix and combustion zones. It reportedly can be used for annular as well as vertical, silo-type combustors.

Catalytic combustion is also in the offing for meeting emissions restrictions at higher and higher temperatures. Leaner combustion can be accomplished by using a catalyst to sustain the reactions. The challenge is to find a catalyst and substrate that can survive in a 2500F environment under thermal cycling normally imposed on gas turbines.

Longer term, gas-turbine cooling and



6. **Multiple combustor arrangements** are necessary to keep NO_x production in check as firing temperatures are increased

or materials technology must be extended appreciably. Ceramic materials for hot-gas-path components are an area of active investigation. For one thing, this can eliminate the complex cooling circuitry needed with today's—and tommorrow's—designs. Ceramic coatings already have been demonstrated, but ceramic construction of combustors and of the first few stages of the hot gas path poses future challenges. Stationary components are likely to come first.

For the combined-cycle application, an interesting option involves steam cooling (Fig 9) of the blades in the first few stages. It is a logical extension of water-cooling techniques developed earlier. Most of the steam's energy can be easily retained in the bottoming cycle, losing only about 2% to various leakage paths. Technical challenges here include understanding the heat-transfer characteristics of steam in the various turbine components and developing adequate seals where the steam enters and leaves the rotor.

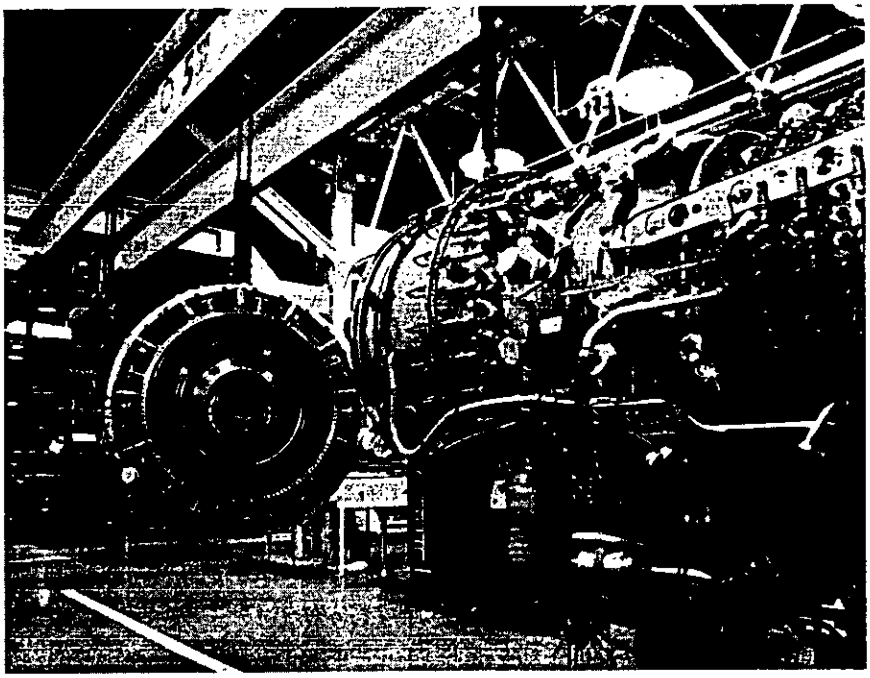
RAM important, too

As impressive as performance gains are, penetration of combined cycles for power generation may depend as much, if not more, on reliability, availability, and maintainability (RAM). In the eyes of many utilities for example, RAM characteristics of combined cycles are suspect because of poor RAM experience with their peaking gas turbines. Whether the reputation is deserved—combined cycles are anticipated to operate many more hours, reducing the thermal cycling imposed on the machine—is a question worth raising. But as operating temperatures, pressures, and service time rise, RAM characteristics will become even more critical.

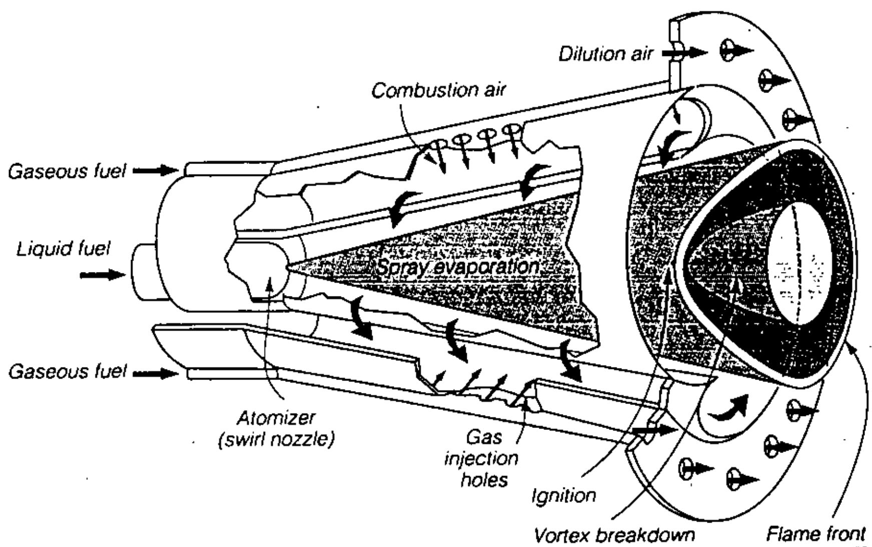
Large gas turbines are scaled up or down (such as from 50 to 60 Hz and vice versa) from smaller designs using basic scaling laws. But the scaling of thermodynamic performance is better known than the scaling of mechanical properties, especially thermal stresses that cause thermal fatigue. Such considerations must be accounted for in machine design.

Turbine vendors are factoring RAM design parameters into their machines in many ways. While one naturally thinks of the high-temperature components, the exhaust end requires some thought as well. Higher exhaust temperatures could lead to greater potential for flutter phenomena. This must be considered in material selection along with other factors.

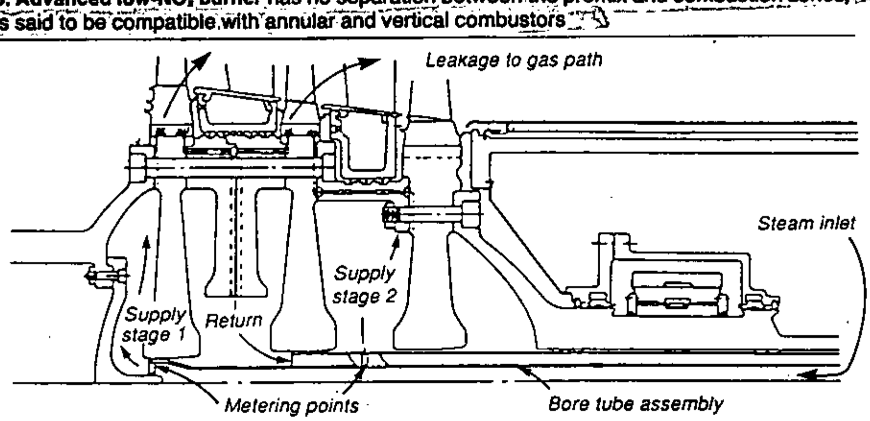
More sophisticated diagnostics may be another way to improve RAM characteristics. Instruments such as optical pyrometers for reading blade temperatures, optical fiber thermometers for monitoring hot-gas temperatures, and combustor viewing probes are being developed.



7. Aeroderivative gas turbines, as part of a combined cycle, increasingly find application in cogeneration in the under-100-MW capacity range



8. Advanced low-NO$_x$ burner has no separation between the premix and combustion zones, is said to be compatible with annular and vertical combustors



9. Advanced cooling of the turbine hot-gas path based on steam flow may be particularly appropriate for combined-cycle application

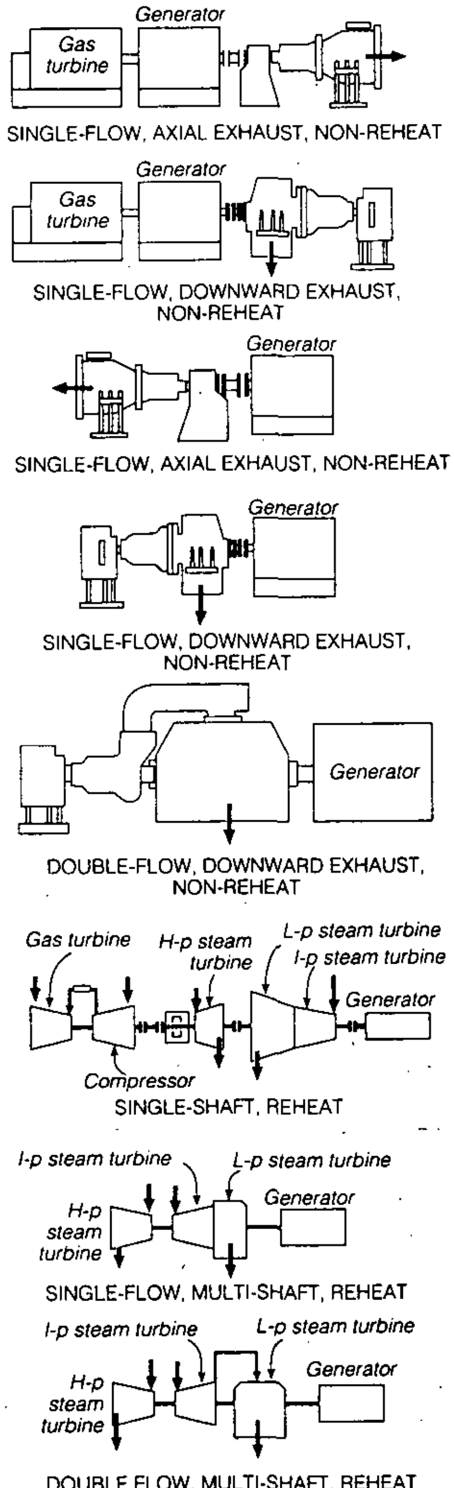
Steam turbines

With respect to combined cycles, steam-turbine technology tends to fall in the shadow of gas-turbine technology. Indeed, the idea is to match the steam turbine to the gas turbine(s), not the other way around—unless an existing steam turbine is being repowered. In fact, much of the steam-turbine-related activity in combined cycles involves developing units optimized for each of the available gas-turbine packages so that the steam turbine becomes a production item much like the gas turbine. Contrast this to the steam turbine that is custom-designed to match the exact output of a field-erected boiler.

At the high end of the capacity spectrum, modestly sized reheat units make sense. Some designs may be more adaptable to reheat. Two-casing single-shaft units, for example, may better handle the differential thermal expansion characteristic of reheat units than single-casing designs. Across the low- to mid-capacity range, wherever possible, single-flow units are employed with axial exhausts. This eliminates the condenser floor and simplifies installation because the entire unit can be at ground level. Other benefits of single flow include lower installed costs and improved efficiency because blades at each stage are longer.

Steam turbines in combined-cycle installations generally operate in the sliding-pressure mode throughout the load range to maintain efficiency. This leads to a relatively simple single-admission steam inlet arrangement. In at least one design, both h-p and low-pressure (l-p) turbine inlets are used. Main steam and l-p steam are mixed prior to expansion in the l-p turbine to reduce thermal stresses.

Another characteristic of combined-cycle application is moderate inlet steam temperatures and pressures, leading to wetter steam in the last stages of the low-pressure stage. This situation is similar to nuclear and geothermal steam turbines. Moisture removal and drainage must be considered along with means of preventing droplet erosion.



10. Many configurations are possible for matching steam turbine to gas turbine

Combined cycles are known for their fast-start and excellent cycling capabilities, but both must be accommodated in steam-turbine design. Areas of concern include: proper matching of steam and metal temperatures, gland-sealing steam temperatures, and axial thrust.

Horizontally split, single-casing designs may be more restrictive than two-casing units with a circumferential split when matching steam and metal temperatures. Other options include: (1) lowering steam pressure to reduce casing thickness and any effects from the temperature differentials, (2) using two half-capacity steam turbines, (3) incorporating steam bypass lines to the condenser, and (4) employing an external means of heating critical parts such as the steam chest and casing flange.

Depending on the types of seals used in the steam turbine, a separate supply of superheated steam may be required if the combined cycle experiences many starts and stops. Reason: Superheated steam from the HRSG cools quickly when the gas turbine comes off line; saturated steam from the auxiliary boiler is only suitable for a cold turbine. Alternatives include an electric or fired superheater or an auxiliary boiler with superheat capability.

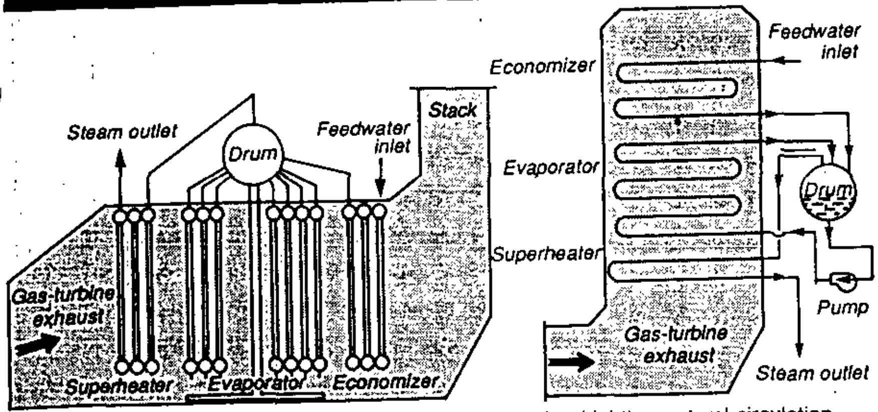
Casing or cylinder arrangements (Fig 10) are varied and depend on, among other things, trade offs between operating and capital costs and the number of gas turbine/HRSG modules the steam turbine will serve. Single-flow single-casing design may be the best choice with only one gas turbine. Two modules can be served with a single-flow single-casing or two-casing double-flow approach. The latter involves higher first cost but better efficiency. The same principle holds for three gas-turbine/HRSG modules: A two-cyinder, double-flow arrangement is less efficient but less costly than a three-cylinder four-flow arrangement.

Now that reheat steam-turbine configurations make sense for combined cycles, it may not be long before supercritical steam turbines add value, too. Supplementary firing can boost steam temperature to beyond 1050F. But the next generation of large gas turbines, predicted to have exhaust temperatures at or above 1150F, can incorporate bottoming cycles with main steam temperatures of 1100F or higher. And, material advances may provide opportunities to superheat steam in coal gasifiers, thereby eliminating the gas-turbine exhaust temperature as the constraint on the steam bottoming cycle.

HRSGs

In combined cycles, the HRSG provides the critical link between the gas turbine and the steam turbine. Once relatively straightforward, the design of the HRSG becomes more involved depending on the application for the combined cycle, the need for NO_x control downstream of the gas turbine, use of supplementary firing, and the need for enhancements to the thermal cycle—such as reheat and multiple pressure levels.

HRSGs for combined cycles are broadly classified as natural- or forced-circulation (Fig 11). In the former, gas-turbine exhaust flows horizontally past vertical tubes. Circulation is maintained by the density difference between the cold feedwater supplied through a downcomer to the evaporator tubes and the water/steam



11. HRSGs are classified fundamentally as forced-circulation (right) or natural-circulation (left). Note vertical and horizontal arrangements

mixture flowing to the steam drum. Forced-circulation units feature turbine exhaust flowing vertically past horizontal tubes. Feedwater is pumped through the tubes.

An alternative to the conventional drum-type HRSG is the once-through design. It eliminates the need for the drum, level controls, and blowdown and recirculation systems. High-alloy construction minimizes feedwater treatment requirements. Several years of experience have been obtained in small industrial cogeneration and combined-cycle systems. More recently, the once-through HRSG has been prepackaged for application to packaged gas turbines as small as 1 MW.

Traditionally, most HRSGs in Europe have been specified as forced-circulation while those in the US are generally natural-circulation (Fig 12). Natural-circulation units tend to be simpler to operate—avoidance of pumps is a primary reason. On the other hand, forced-circulation units can generally be made smaller, particularly with respect to plot space, and can be started up faster, although the actual differences in size and startup time may be small, and depending on the application, not significant. Proponents of both claim ease in handling a wide range of gas-turbine load and exhaust characteristics.

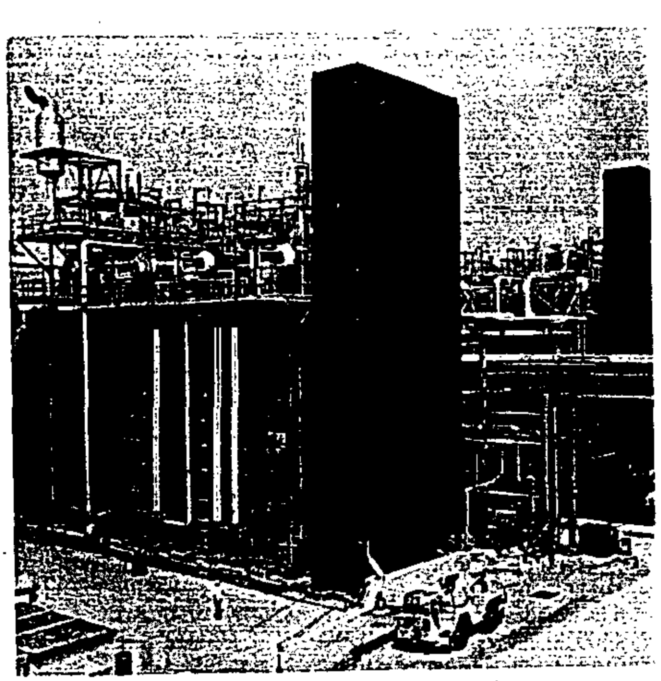
Variations in both gas-turbine exhaust velocity and temperature must be accounted for in HRSG design. Changes in ambient-air conditions, load, and/or quantities of steam or water injected into the combustor for NO_x control all affect the flow pattern experienced by the HRSG. This situation can be complicated by having two or more gas turbines exhausting into one HRSG. Flow straighteners are often specified to make the HRSG gas inlet more uniform.

In combined-cycle cogeneration applications, two- and three-pressure-level HRSGs may be required (Fig 13) and a few units have four pressure levels with over a dozen superheater, evaporator, and economizer sections. L-p steam is usually used for feedwater heating while medium-pressure steam may be used in the process and h-p steam feeds the steam turbine. The deaerator may be mounted on top of the l-p steam drum.

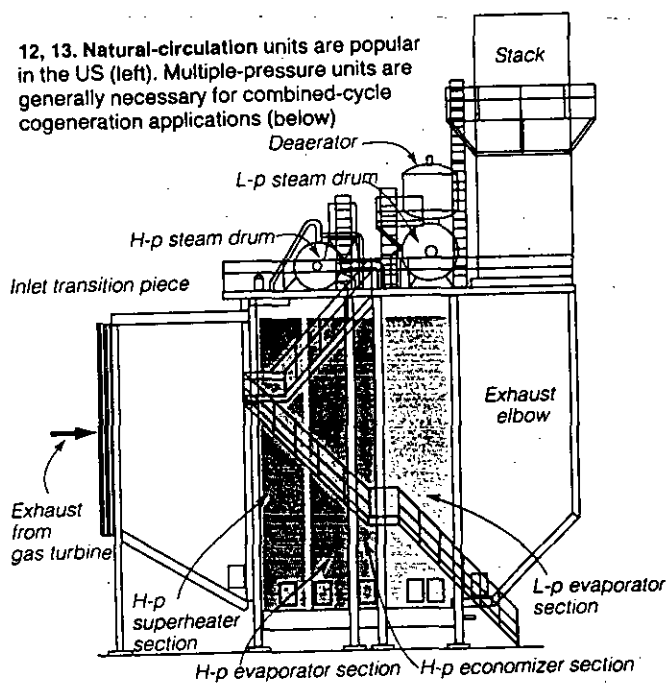
One way to maximize heat recovery is to cascade steam-drum continuous blowdown. That is, blowdown from the h-p steam drum passes to the medium-pressure steam drum where it flashes and steam is recovered. Likewise, heat in the medium-pressure drum blowdown is recovered in the l-p drum.

As steam temperatures and pressures are elevated to meet the requirements of today's combined cycles, they must be accommodated in HRSG design. Thermal stresses are particularly important because the system must retain its rapid-start/stop and load-cycling capabilities. Consider the mass and thermal load being directed to or away from the HRSG in the span of a fraction of an hour as a gas turbine is started up or shut down. Also, the steam cycle of combined cycles is usually operated in sliding-pressure mode, meaning that h-p drum pressure evolves like steam flow which follows the gas-turbine load. The resulting transients become important in drum and other HRSG component design to ensure adequate life and prevent deterioration from fatigue.

Dewpoint corrosion becomes more of a factor as designers strive for the lowest stack temperatures by including feedwater heating in the HRSG. Acid-dewpoint corrosion must be accounted for if the fuel being burned has even a trace of sulfur in it. Also, potential for water dewpoint corrosion increases when water or steam is



12, 13. Natural-circulation units are popular in the US (left). Multiple-pressure units are generally necessary for combined-cycle cogeneration applications (below)



injected into the combustor for NO_x control because it greatly increases the moisture content of the turbine exhaust.

Flexibility, but also cost, is added to the system by providing an HRSG bypass, allowing the gas turbine to operate in the simple- or combined-cycle mode and/or to modulate flow to the HRSG. Keep in mind that the dampers required for this service are often found to be unreliable and special attention to them is required in both design and operation and maintenance.

Louver dampers may allow better control over exhaust flow than flap-type dampers but they exhibit higher leakage rates. Size will also play a role in selecting the appropriate damper as will application. Cogeneration plants may find that the louver's modulating ability outweighs leakage drawbacks. Plants intended for base-load power generation may avoid the bypass altogether while ensuring that the HRSG can withstand temperature gradients. Another alternative is to implement a steam-turbine bypass system for simple-cycle operation.

Supplementary firing

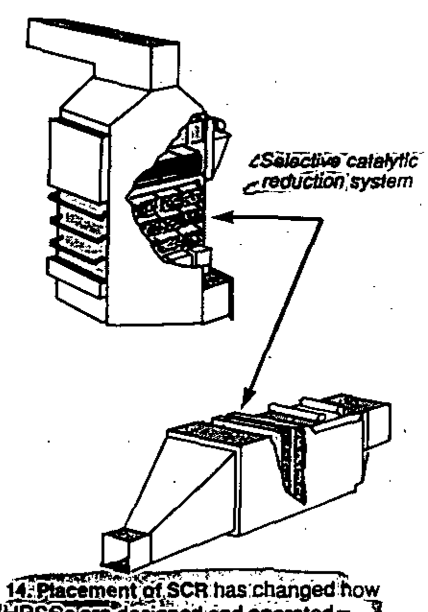
In some combined-cycle applications, more steam is needed than may be available from just the gas-turbine exhaust. Supplementary firing of gas or oil directly into the hot exhaust with a duct burner upstream of the HRSG yields important advantages, especially because the exhaust has enough oxygen to sustain good combustion. For one, an optimum match can be made between electric power and steam needs to maintain system output throughout the load range.

In some cases, the burner must also be designed to supply all the necessary heat input for full steam generation—using a separate fan for the combustion air source—when the gas turbines are down. In past years, this downtime may have reflected mostly planned or unscheduled outages, relatively short periods. Recently, though, dispatchability has become a requirement for some gas-turbine-based cogeneration systems. Depending on the purchasing utility's seasonal load curves, the auxiliary burner may be called upon to maintain steam output for a long period of time.

With the burner elements constantly exposed to exhaust temperatures of 900F or more, the design must be extremely robust and include alloys capable of withstanding these temperatures day in and day out. Regardless of whether O_2-starved exhaust or ambient air is the "air" source, the burner design will still have to ensure that emissions, especially CO, are kept within compliance. Fuel piping, flame safety logic, and combustion controls must also be flexible enough to handle the varying conditions.

SCR in the HRSG

Need for selective catalytic reduction (SCR) has certainly changed the way



14. Placement of SCR has changed how HRSGs are designed and operated

Combined cycles run gamut of sizes for cogeneration service

As utility application of combined cycles dwindled in the mid- to late 1970s, cogeneration and small power took up the slack—at both ends of the size spectrum. Systems as large as 465 MW (Fig A) serve in areas like the Gulf Coast and California where the industrial appetite for steam and power persists, where growth demands expansion of generation capability, and/or where state legislation provides incen- (continues on p 112)

A: Large Gulf Coast combined-cycle plant is independently owned and supplies large quantities of process steam to adjacent industrial facility

B: Combined-cycle system for cogeneration serves a university in Colorado; makes use of highly packaged aeroderivative gas turbine

HRSGs are designed and operated. Recall that SCR involves the injection of ammonia into flue gas upstream of a catalyst structure (POWER special report, *Reducing NOx emissions*, September 1988). NO_x is catalytically reduced to nitrogen and water.

To meet the temperature requirements of the catalytic process, the SCR is usually sandwiched in between HRSG components (Fig 14). Location depends on matching the process temperature window of the catalyst with the proper window in the HRSG. But the HRSG temperature profile is a moving target that depends on gas-turbine load and ambient air conditions. Gas velocities through the SCR portion of the HRSG may have to be adjusted to meet residence-time requirements for the NO_x-reduction reactions.

Other considerations include ensuring proper control of ammonia injection (Fig 15) and mixing with turbine exhaust. Note that the NH_3 injection-nozzle grid may be located relatively far from the catalyst structure. Also, if sulfur is present in the fuel—and as SO_3 in the exhaust—it can react with ammonia to form, among other compounds, ammonium bisulfate which can promote rapid corrosion of downstream heat-transfer tubes. Provisions for water washing the cold section of an HRSG with SCR should be considered.

SCR in the HRSG may also limit operational flexibility. Supplemental firing can drastically change the temperature profile throughout the HRSG and turndown of the gas turbine must be accomplished while maintaining the exhaust in the correct temperature range. It may difficult to meet emissions limits if turbine exhaust is bypassed around the HRSG. As a final note, realize that as required NO_x removal efficiencies go up, it becomes more difficult to optimize the SCR process.

(continued from p 110)
tives or encourages the practice. Some are operated by so-called independent power companies who sell the steam to an industrial site and power to the utility. More recently, large combined-cycle plants have been constructed or planned for East Coast sites (Fig D).

These large systems represent the state-of-the-art in combined-cycle applications today. Many operate base load but some also are designed to be dispatchable—that is, the utility purchasing the power output can dictate when and at what load they should operate. They must be configured and controlled to reliably provide electric power on requirement *and* meet the steam demand of the industrial host. Steam demand can fluctuate widely within small time periods.

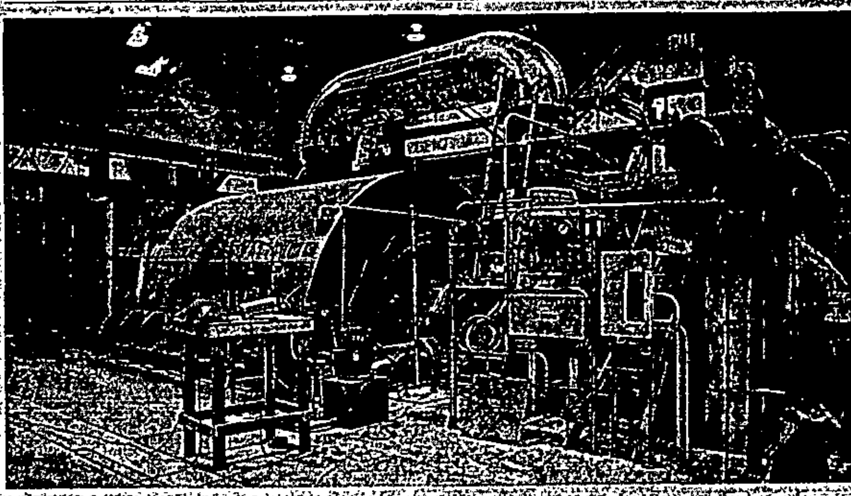
Experience with cogeneration and independent powerplants reportedly has been very favorable, although several more years of operation will be required to provide a meaningful data base on reliability and availability—a data base that the utilities undoubtedly will be interested in as they consider combined cycles for base-load power generation.

Combined cycles based on aeroderivative gas turbines (Figs B, C) are popular choices for cogeneration in the 10-100-MW capacity range. While most are fueled by natural gas, with distillate as backup, many fire methane from sewage treatment plants and landfills and refinery byproducts. Availability of digital controls has gone a long way toward making these systems manageable by operators or personnel with little training or experience with power equipment.

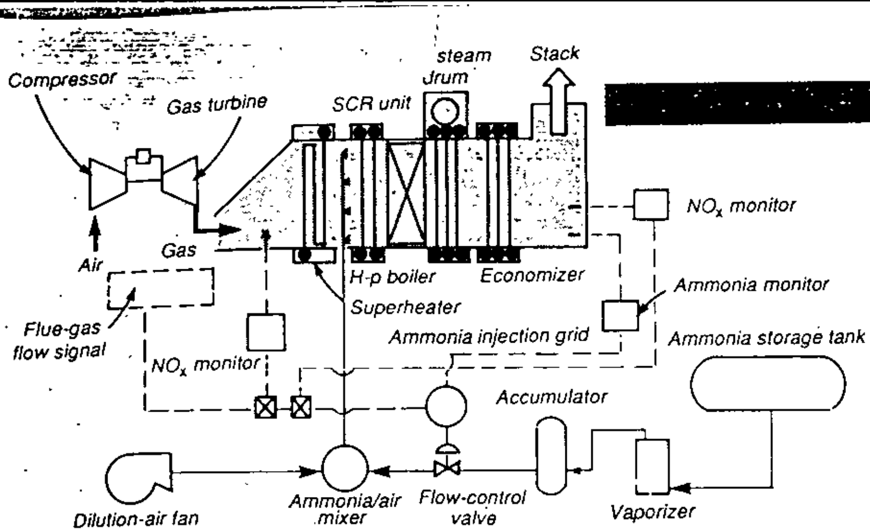
Many small systems take full advantage of laws requiring local utilities to buy back the power. Indeed, the steam-turbine cycle is often added mainly to increase electric power output while having just enough steam output to meet the efficiency requirements of the Public Utility Regulatory Policies Act of 1978—the legislation that promoted independent power.

Popular in Europe, although not in the US, is the idea of using combined-cycle systems for district heating. Here, power generation is sacrificed somewhat so that steam is of sufficient quality to circulate through what often amounts to miles of piping. Thermal efficiency of these plants is nominally 80%. By their nature, district heating systems must be sited close to urban centers, dictating clean combustion.

C: Entertainment center receives electric power and process steam from combined-cycle system based on aeroderivative gas turbine



D: Large cogeneration combined-cycle plants have more recently been installed at sites on the East Coast



15. The injection of ammonia for SCR can significantly affect the reliability and maintainability of the HRSG, and must be factored into design

Auxiliary systems

While the gas turbine, HRSG, and steam turbine comprise the major components of the combined cycle, many other components are necessary to complete the installation and/or to optimize performance. Only a brief mention of some of these is given here as more complete information is available elsewhere.

Water system

Combined cycles consume less water than competing forms of power generation. Nevertheless, competition for water is intensifying among such interests as agriculture, industry, residences, and recreation and wildlife preserves. Where water is available, its quality may be less than desired. Thus, the minimization of raw water makeup—either through greater water recycle within the plant (Fig 16) or by selecting alternatives to water use—will drive the design of combined cycles as it will other types of powerplants.

Avoiding water cooling is one way of sharply cutting down on water consumption. A direct air-cooled condenser can be used in place of the traditional surface condenser. So-called dry cooling towers avoid the plume and blowdown characteristic of wet cooling towers; however, dry cooling is not nearly as thermally efficient as wet cooling.

Boiler-feedwater treatment must receive more attention as steam temperatures and pressures rise to meet the performance goals of today's combined cycles. While utilities are likely to be familiar with these more stringent requirements, other potential users whose experience is limited to lower steam conditions should understand high-purity feedwater treatment.

Conditioning of inlet air

Higher temperatures in gas turbines and the need to maintain efficiency from base-load combined cycles dictate inlet-air treatment (Fig 17) that is more involved than it has been. Air filters, always a common element, now include pulse-jet fabric filters for extreme duty in addition to more conventional barrier and panel filters that can be equipped with automatic self-cleaning mechanisms. Microprocessor-based controls may be specified to avoid excessive pressure drop under all operating conditions.

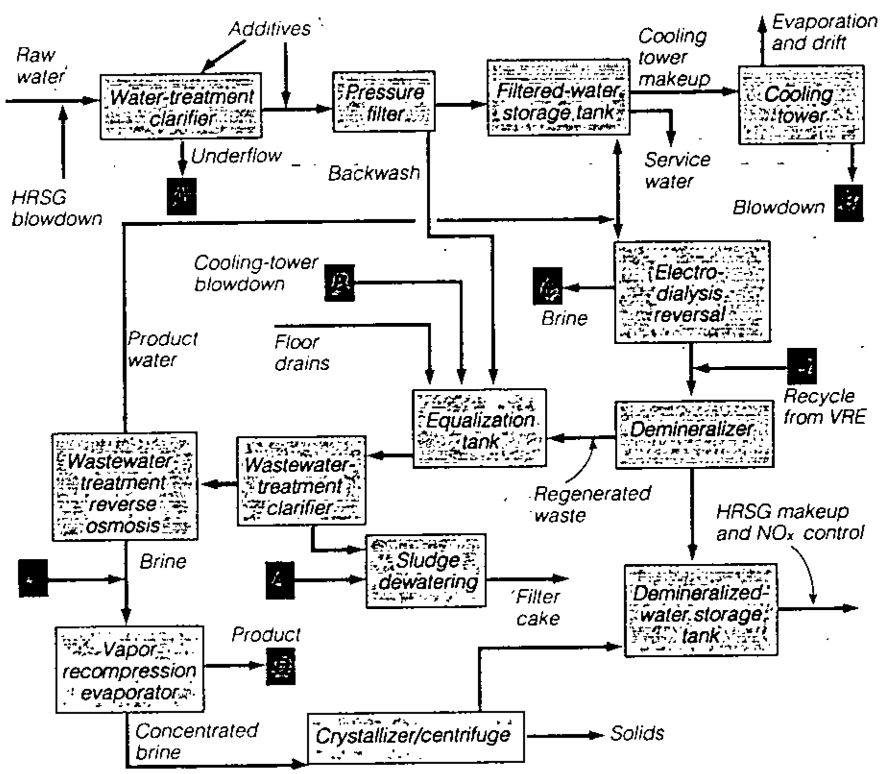
Ambient-air temperature has a signifi-can't effect on combined-cycle output. For this reason, evaporative coolers have been used more extensively in recent years to maintain output, especially in regions having extended periods of high temperature and/or high humidity. Evaporative coolers convert sensible heat into latent heat without changing the total heat content of the mixture. This increases the moisture content and density of the air. Removal of soluble contaminants and some NO_x reduction are other claimed advantages.

Fuel systems

Like those in the inlet air, contaminants that find their way into the gas turbine from the fuel can cause considerable loss of performance and can contribute to premature degradation of hot-gas-path components and heat-transfer surfaces in the HRSG. Much of the experience with combined cycles comes from installations where clean fuels are fired and fuel preparation is minimized.

A few installations routinely fire crude or residual oil which does require considerable fuel treatment, particularly the removal of salts and suspended sediment. However, performance still tends to suffer compared to systems fired by natural gas and distillate.

Regarding fuel systems, an important point to remember is that secondary or backup fuels may have to be used. Backup fuel systems require periodic inspection and maintenance, especially when they've gone a long time without use.



16. Though water consumption by combined cycles is less than for competing systems, approaching zero discharge will still be an important consideration

Oil storage tanks and handling systems are a particular area worth investigation. Resid and distillate fuels are both subject to oxidation and deterioration resulting in the accumulation of dirt, sediment, gum deposits, and sludge. Microbial growth at the fuel/water interface can cause severe pitting-type corrosion. And if coal gas is to be used at some point, it is critical to understand how even minute quantities of contaminants can affect combined-cycle performance.

System integration

A basic understanding of combined cycles is not complete without a review of those factors that affect the entire system. Here the term integration refers to physical integration of the primary components described above and factors important to the operation and performance of the combined cycle as a whole—such as operating mode, reliability/availability issues, and control systems. Also covered in this section are combined steam and gas cycles that do not involve a steam turbine.

As you review this information, keep in mind that as the combined cycle moves into base-load generation duties—either for cogeneration or power generation—further integration of the steam and gas cycles is inevitable.

Reheat

As mentioned earlier, the new large gas turbines have exhaust temperatures high enough to justify reheat in the steam cycle without supplementary firing (Fig 18). This represents the highest efficiency combined cycle available today.

Depending on the how the reheat cycle is configured (Fig 19), the thermal performance at rated conditions can vary by up to three percentage points, according to one estimate. It is interesting to compare this gain to that achievable with advances in gas-turbine firing temperature or in the steam cycle from higher main-steam pressure and temperature. The reheat surface is easily placed in the HRSG. One possibility is to arrange it in parallel with the superheater.

Note that reheat temperatures—in the range of 950 to 1000F—generally are close to those used in conventional fossil plants. Reheat-steam pressures are, however, more moderate, less than 500 psig. An important difference: Feedwater is heated by gas-turbine exhaust, not by extraction steam. Feedwater heating is often the subject of economic optimization for conventional fossil-fired plants, leading to custom design of the steam turbine. Avoiding extractions helps designers standardize steam turbines for the combined cycle. Condensate can be deaerated in the condenser.

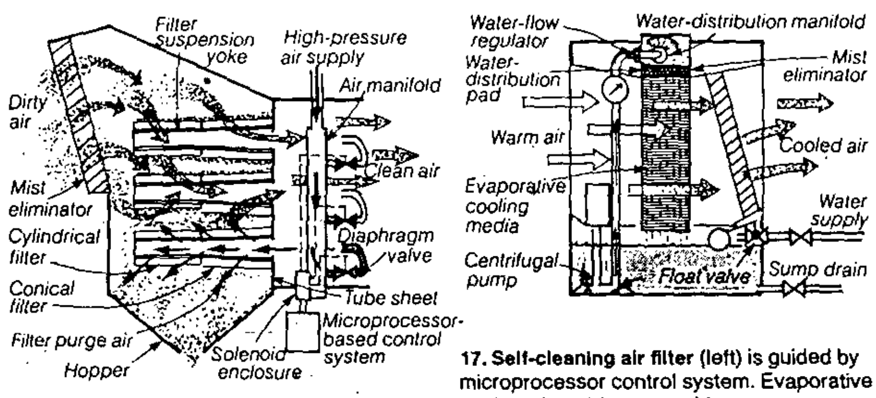
Reheat offers other advantages as well. It reduces the moisture content of the steam in the last few l-p turbine stages. This can lead to use of longer last-stage blades and more compact single-flow turbine instead of a double-flow arrangement. On the other hand, higher steam temperatures and pressures call for use of shorter blades on the steam-turbine inlet stage. This leads to steam leakage losses and must be accommodated in design.

Single-shaft units

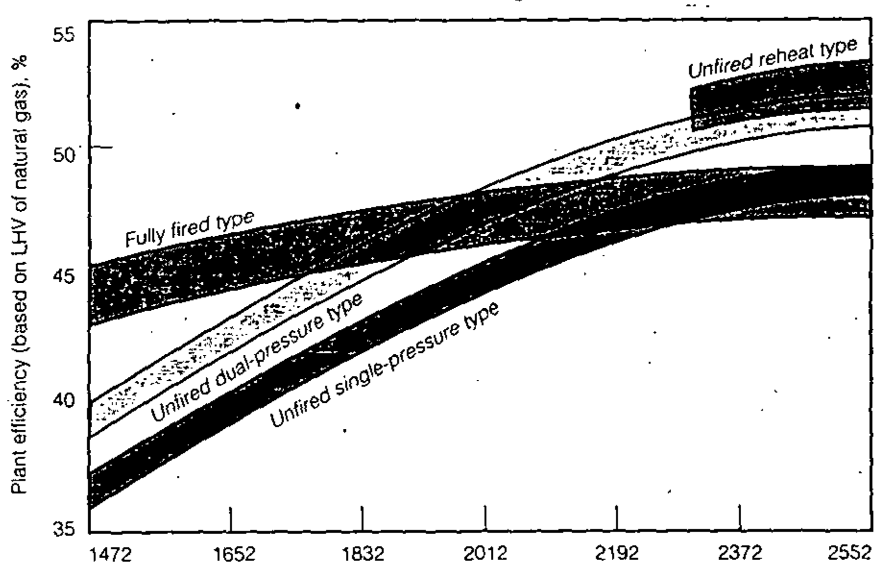
A recent advance in combined-cycle design that is likely to have important applications is combining the gas turbine, steam turbine, and generator on a single shaft (Fig 20). While this has been available for years for smaller non-reheat units with single-casing steam turbines, the concept has now been applied to reheat units with h-p, intermediate-pressure (i-p), and l-p turbine elements. Even a double-flow l-p casing can be accommodated in the single-shaft arrangement, although this application is more challenging.

Features of one manufacturer's single-shaft design include: a single thrust bearing, all rotors connected with solid couplings, a common control system that integrates operation of the inlet steam control valve with the gas-turbine fuel and inlet guide-vane controls, and common lubricating and hydraulic control fluid systems. The generator is connected to the inlet end of the i-p turbine.

Like all condensing steam turbines, whether single- or multi-shaft, the annulus area of the exhaust must be matched with condenser pressure for a given site. Different l-p sections having varying last-stage blade lengths can be selected to optimize the steam turbine to the plant site.



17. Self-cleaning air filter (left) is guided by microprocessor control system. Evaporative cooler (above) boosts turbine output



18. Higher firing temperatures in today's gas turbines help to justify reheat steam cycles without the inefficiency of supplementary firing

Although there are trade offs in the thermodynamic performance of the single-shaft arrangement, the vendor indicates that overall performance is essentially identical to that of a multi-shaft design. The single-shaft approach does involve special considerations in the area of thermal expansion and movement and rotor flexibility.

Obvious, but worth noting, is that the single-shaft arrangement takes away the flexibility of installing a simple-cycle gas turbine first and then adding a steam turbine at a later date.

Operating modes

Combined cycles offer much in terms of operating flexibility. In the most basic sense, the gas turbine can be operated simple-cycle or in the combined mode. This allows the plant to satisfy capacity requirements in increments and also to produce electricity during steam-cycle component outages. Basic economic decisions must be made regarding the extent to which individual gas-turbine modules should share auxiliary systems.

Advanced coal processes add fuel flexibility to combined cycle

When it comes to selecting the generation technology for base-load electric-utility service and large-scale cogeneration, conventional wisdom has always penalized the combined cycle for its inability to use coal, the world's most abundant fossil fuel and the one most stable in price over the long haul. With the commercial introduction of advanced coal-conversion and combustion techniques (Fig A), this argument has been effectively removed. However, it is important to understand how coal-based processes affect the design, operation, and performance of a combined-cycle powerplant. Special emphasis must be placed on how the process can be integrated with the combined cycle to increase efficiency—that is, compared to a non-integrated plant design.

For near-term use, coal gasification (CG) and pressurized fluidized-bed combustion (PFBC) are viewed by industry experts as the most important technologies. Both are available today from a variety of suppliers in combined-cycle modules of several hundred megawatts or more. And, both are in the process of being demonstrated at capacities large enough to attract widespread industry interest. However, the scale at which these processes have been operated is not necessarily the same scale at which they are being offered commercially. And it is important to realize that these systems will not be as efficient as combined cycles firing premium fuels.

CGCC and PFBC-CC represent wholly different approaches to matching combined-cycle efficiencies with coal utilization. In the CGCC approach (Fig B), coal is first gasified, then fired in a combustion turbine. Like conventional combined cycles, around two-thirds of the total power output comes from the gas-turbine cycle, one-third from the steam cycle. The gasifier can be fully decoupled from the powerplant acting only as a fuel supplier, or the two can be integrated to whatever degree is desirable. Users contemplating the later addition of gasifiers to combined cycles need to appreciate this fact.

Depending on the gasification process, decoupling can involve substantial penalties on cycle performance. Areas that should be considered include: (1) design of the gas turbine combustor to burn coal gas without sacrificing efficiency or environmental performance; (2) need for high-temperature, high-pressure coal-gas cleanup—a technology

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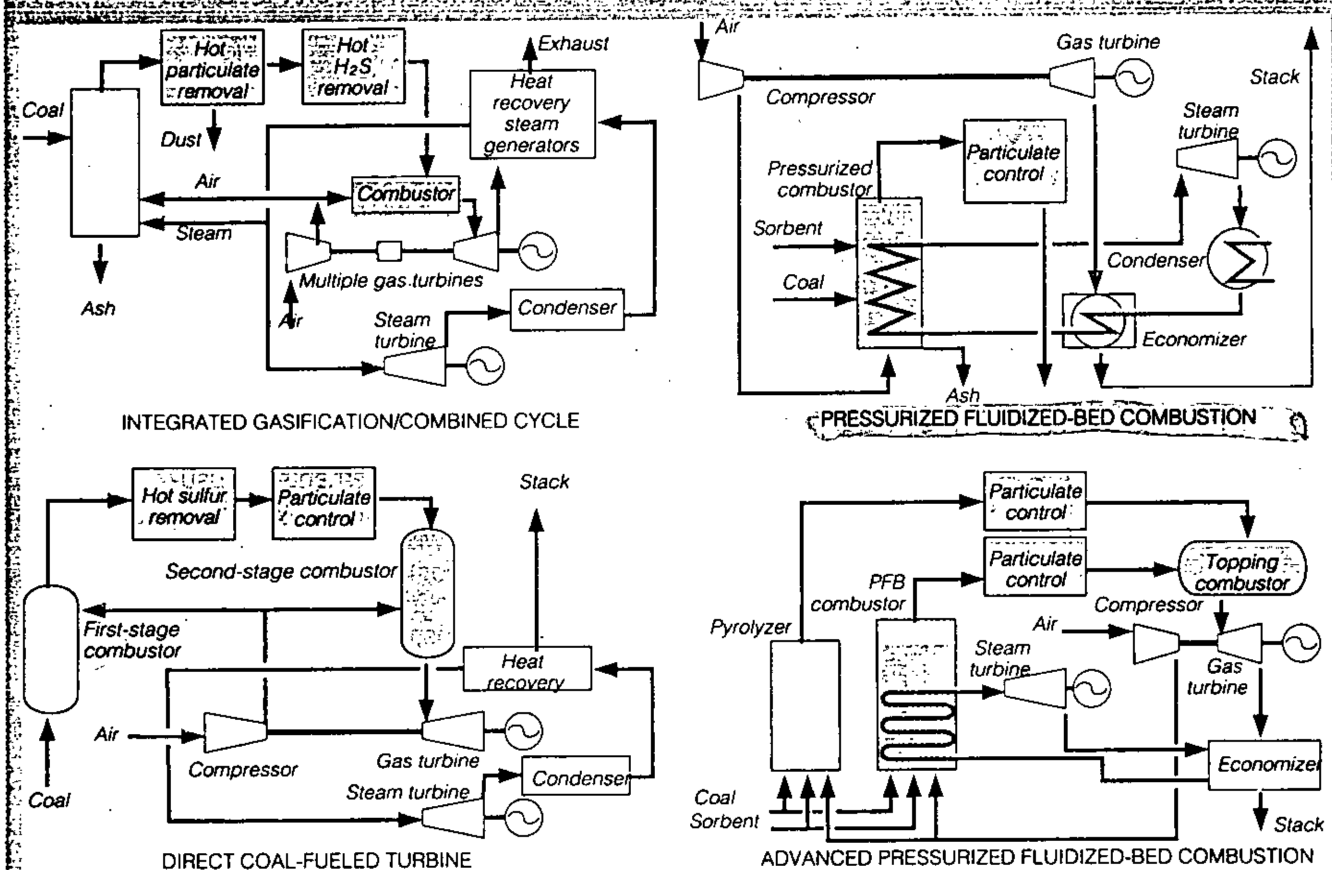

A: Advanced coal combustion, conversion techniques promise to extend the application range of combined cycles

Flexibility is extended as gas turbines, steam turbines, and HRSGs are added to the system. The largest combined cycle supported by one of today's large gas turbines is between 200 and 300 MW. On the one hand, this allows incremental addition of base-load capacity as well as leads to smaller blocks of power that might be forced or scheduled out of service. On the other, several modules are required to equal the same capacity available from a typical base-load boiler/steam turbine combination.

Several modules imply a high degree of system operating complexity. To illustrate: Consider the case of two gas turbine-generators each coupled to a supplementary-fired HRSG and a single condensing steam turbine/generator. Several of the possible operating modes are: (1) one or two gas turbines operating and bypassing both HRSGs, (2) one or two gas turbines exhausting into the HRSGs with or without supplementary firing, (3) one or two gas turbines exhausting into the HRSGs but with the steam turbine off-line, and (4) either gas turbine exhausting into its

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that lead gasification in commercial development—to take full advantage of the fuel's sensible heat, (3) use of steam recovered in the gasification section in the steam bottoming cycle, and (4) options for using compressed air from the gas turbine in the O_2-producing plant, and/or (5) returning N_2 from the O_2 plant to the gas turbine to act as a diluent—in place of steam—in the combustor to limit NO_x production and to increase mass flow through the unit.

The reason hot-gas cleanup is so important is that it allows a greater proportion of the coal's energy to be recovered in the gas-turbine cycle, which is thermodynamically more efficient than the steam cycle. Even without hot-gas cleanup, a highly integrated design is expected to achieve heat rates of around 8000 Btu/kWh assuming a gas-turbine inlet temperature of 2300F. Experts say that this can be lowered to 7500 Btu/kWh by the year 2000 as CGCC technology evolves.

In the commercial PFBC-CC approach (Fig C), the steam cycle produces about 75% of the power output. Here, the pressurized flue gas from the combustor is cleaned of particulates, alkali, and other contaminants, and then flows to the gas turbine. The gas turbine exhausts into a conventional HRSG. Steam for the bottoming cycle is also produced in tubes located in the fluidized bed.

Combustion air for the pressurized boiler is provided by the gas-turbine compressor. Pressure ratio of the gas turbine is matched to the operating pressure of the combustor. Pressurizing the system offers general process advantages of making primary equipment smaller, more amenable to shop fabrication, and easier to ship.

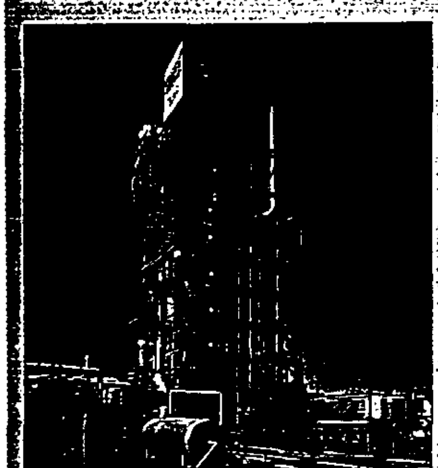
Overall cycle efficiency is limited by the operating temperature of the fluidized bed—around 1600F—which in turn limits the turbine inlet temperature. New PFBC-CC plants could achieve heat rates in the range of 8500 to 9000 Btu/kWh, assuming a subcritical steam cycle.

Several alternatives can be considered for overcoming the limitation on turbine inlet temperature. One that involves no technology extension is to employ an afterburner, or topping-combustor, scheme. If the inlet temperature is raised to 2300F, heat rates below 7000 Btu/kWh can be achieved. Another way around the temperature limitation, which involves a fundamental change to the process, is to partially gasify the coal first, burn the fuel gas in the gas turbine, and burn the char from the partial gasifier in an atmospheric or pressurized fluidized-bed boiler. This scheme has the potential to raise cycle efficiency several percentage points—over today's state-of-the-art PFBC-CC; however, a new level of coal processing is added, with attendent increases in capital cost and operational complexity.

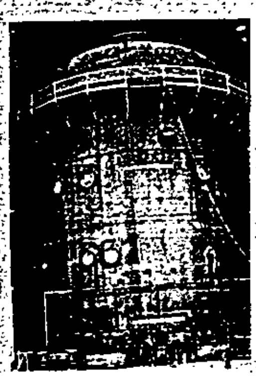
Regarding the bottoming cycle, the PFBC-CC can take advantage of steam-cycle advances. In particular, the use of the supercritical steam cycle, advanced more substantially in Europe and Japan, can add to PFBC-CC efficiency.

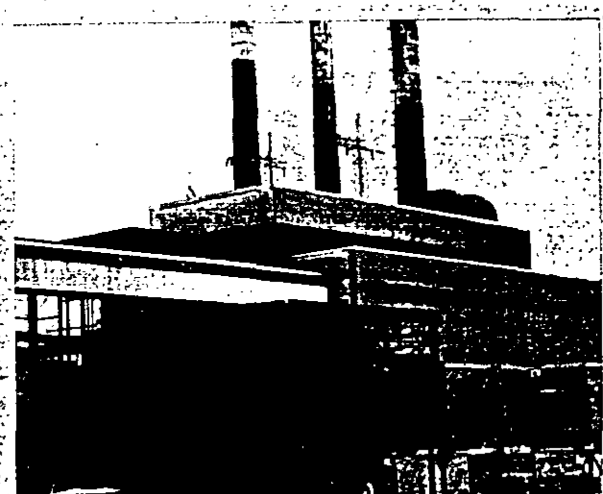
Air-cooled tubes can be used in the pressurized combustor instead of steam-cooled ones. This high-temperature air is then combined with the clean flue gas from the combustor and feeds the gas turbine. Among other things, this allows a greater output from the higher-efficiency gas-turbine cycle than from the steam cycle. Steam is generated only by the gas-turbine exhaust. Note that such an indirect-fired combined cycle can be accomplished with an atmospheric fluidized-bed air heater, too, although materials for the air heater require further development and demonstration.

Another technology being developed for making coal compatible with combined cycles is the slagging combustor, essentially a very small gasifier that can be thought of as an external combustor for the gas turbine. Development of the slagging combustor, though close to being demonstrated commercially for conventional boilers, is several years behind the above-mentioned gasification and fluidized-bed technologies for combined-cycle application.



B. Coal gasifiers have been demonstrated at several sites in the US





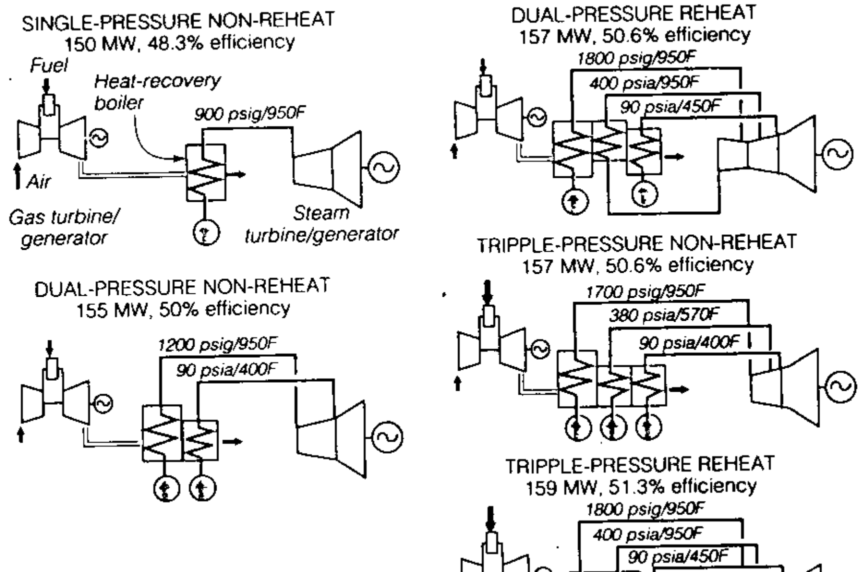
C. Pressurized fluidized-bed combustor (above) is ready for demonstration at site in Ohio (right). PFBC-CC plants also have been built in Europe

HRSG, with or without the steam turbine, while the other HRSG is bypassed.

The control system must coordinate these various operating modes. Today's distributed control systems make coordinated control a lot easier than it was in the past. In general, even large combined-cycle plants can be operated by one person in a central control room, although startup may require another person at a local control site or roving the equipment.

Each individual combined cycle also can be turned down for more flexibility, although unit performance suffers at part load—more significantly at less than 50% of gas-turbine output. One aeroderivative machine is described as performing at between 115 and 120% of its rated-capacity heat rate when operated at 50% of rated load.

Deterioration in part-load performance can be held in check with multiple modules because both can share load equally, minimizing turndown of individual gas turbines. Also, use of variable-inlet guide



19. Reheat, depending on how it is integrated into the combined cycle, can improve thermal performance by several percentage points

Repowering/retrofit schemes reveal design ingenuity

A major market segment for combined cycles involves the retrofit/repowering of existing equipment to improve efficiency, add capacity, and/or meet new environmental regulations. Because retrofits are so site-specific, the examples described here are intended only to represent the range of applications that have been demonstrated over the last few years.

Perhaps the most obvious retrofit is the addition of an HRSG and steam turbine to one or more existing gas turbines (Figs A, B). Many sites have converted peaking gas turbines this way. Basic non-reheat, single-flow steam turbines with two-drum HRSGs are logical equipment selections. SCR and/or steam/water injection into the combustor must be considered for NO_x control. Upgrades to the gas turbine—such as the addition of modulating inlet guide vanes, new hot-gas-path components, and digital controls—and addition of feedwater and cooling water systems are other aspects worthy of consideration.

Another approach: Steam turbines can be repowered with one or more gas turbine/HRSG modules when the existing boiler is no longer economical to operate. This scheme gets most attention as a way to meet new environmental restrictions, especially on old, relatively small fossil-fired steam units while avoiding the installation of emissions control equipment that may re-

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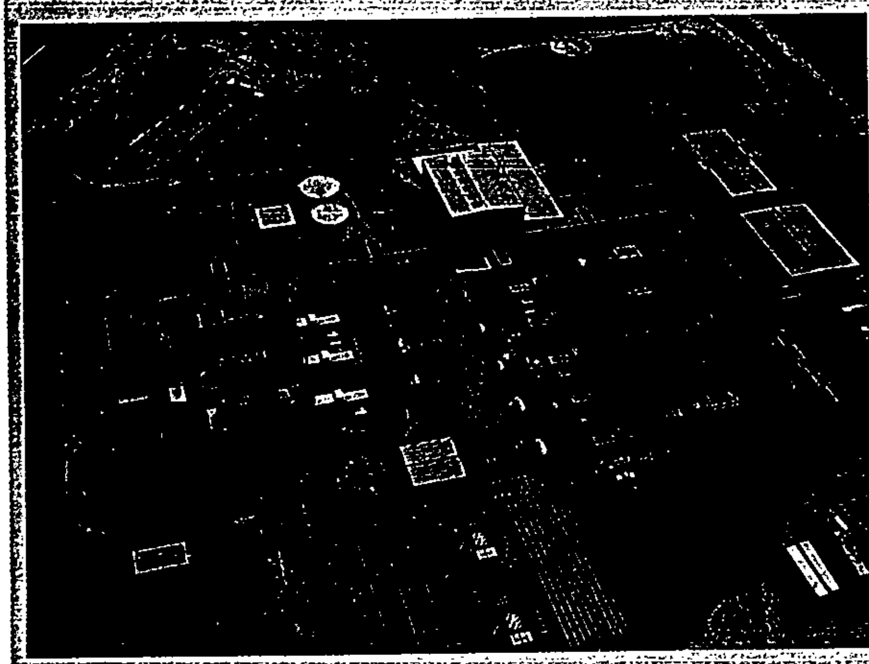
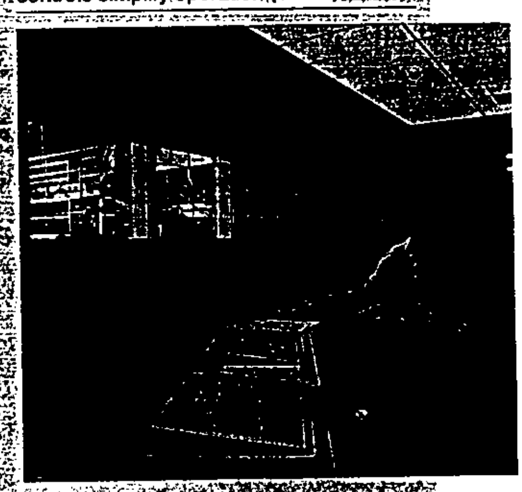


A. Combined cycle boosts efficiency (left), controls simplify operation (below)



vanes on the gas-turbine compressor helps to maintain efficiency at part load. They allow partial control over steam temperature but at the expense of gas-turbine electric output.

Part-load operation also impacts emissions. CO emissions increase as load decreases and as steam/water is injected to control NO_x. Depending on the site permit, part-load operation may be restricted.

Very rapid start/stop capability is also characteristic of combined cycles, more so of the gas-turbine portion of the plant. Although start scenarios will vary substantially depending on the size, type of design, number of units, and other factors, here's a cold-start example with a multi-shaft system having two gas turbine/HRSG trains and one steam turbine:

Both gas turbines are started with HRSG bypass dampers fully open. One gas turbine is kept at 50% load with its adjustable guide vanes wide open to produce low exhaust temperatures. After eight minutes, the damper to the first HRSG is modulated to produce low main-steam temperatures for warmup of the steam cycle. Initially, steam bypasses the turbine. After 35 minutes, the proper steam conditions are established for loading and synchronizing of the steam turbine/generator. Within 75 minutes, the bypass of the first HRSG is fully closed and the half-loaded gas turbine is brought to rated load. The second HRSG bypass dampers are modulated to admit steam and two hours into the startup sequence, both HRSGs are at rated conditions. After about five minutes more, the second HRSG bypass is fully closed and all steam is directed to the steam turbine. Thus, full load is achieved in two and a half hours.

Reliable on/off cycling is dependent on auxiliaries—such as the starting-motor system. A failure to start leads to a second attempt. Because starting raises motor temperature substantially, you can avoid delays between starts by specifying a motor making at least two successive starts without cooling delays.

Another consideration for on/off cycling involves the HRSGs. They commonly have small steam drums and level can be difficult to control at the low flows common during startup. A steam bypass to the condenser is worth considering to improve stability during startup.

How combined cycles meet the demands for process steam in cogeneration applications is also worth reviewing. Here, the combined cycle may have to fluctuate between operating in a maximum power or maximum steam mode. To accomplish this, some of the operating flexibility may be compromised.

Consider a system with multiple gas turbines and single automatic-extraction steam turbine. If the steam turbine is out of service, one or more gas turbines may also be shut down to avoid producing too much process steam. An alternative is to operate the gas turbines at part load—sacrificing efficiency—so that full process steam can be provided quickly in case of a gas-turbine outage or increased demand.

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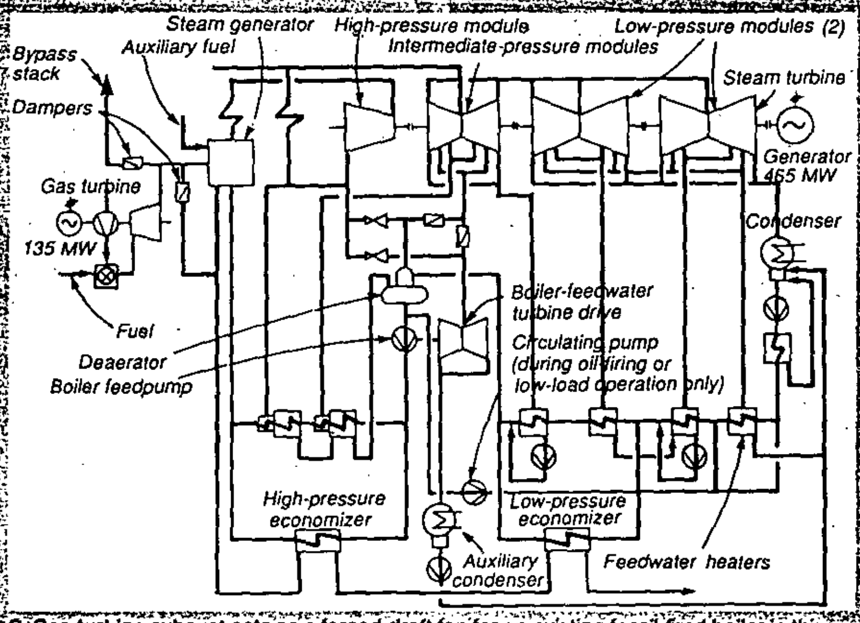
duce output and/or efficiency. Depending on operating conditions, steam turbines may be more amenable to life extension than their accompanying boilers.

Similarly, the performance of existing fossil-fired units often can be improved by replacing the forced-draft fan with a gas turbine and directing its exhaust to the boiler as high-temperature combustion air.

This so-called turbocharged boiler (Fig C) concept has been implemented successfully at several locations in Europe and in the US. Areas of attention include matching the exhaust flow of the gas turbine to the boiler, replacing the air heater with feedwater-heater economizers, and resizing burners to handle different flow rates. The operating flexibility of the turbocharged-boiler cycle, similar to a conventional combined cycle, can be envisioned by considering the existing boiler a fired heat-recovery unit.

A unique repowering concept is the conversion of a nuclear-designed steam turbine to operate as a combined cycle. The first conversion of this type was conceived as a way to salvage a substantial investment in a nuclear plant that otherwise would have been abandoned. As one might suspect, substantial changes are required of the steam turbine, such as removal of feedwater-heater extractions, eliminating reheat, accommodation of higher steam temperatures and pressures, and addition of larger extractions if used for cogeneration. This conversion required a new h-p/i-p element.

B. Adding steam cycle converts peaking gas turbine for base-load operation



C. Gas-turbine exhaust acts as a forced-draft fan for an existing fossil-fired boiler in this repowering scheme applied in Europe