Gas turbine considerations in the pulp and paper industry

J. Steven Anderson and John M. Kovacik

Gas turbine technology has evolved to the point where it offers sufficient reliability and flexibility to significantly improve upon steam-cycle economics typically used in the industry.

The pulp and paper industry is one of the largest users of energy in the industrial arena, requiring large quantities of process steam and electrical energy per unit of production. Developing power generation as an integral part of its power plant systems is one way for the industry to meet these requirements. Steam turbines are one method of power generation that must be given serious consideration in mills with suitable economic conditions, particularly since a wide variety of steam turbine types already have been installed and are contributing toward profitable operations. Gas turbine-based cogeneration systems can also be a desirable approach.

In recent years, competitive pressures, environmental concerns, the cost and availability of various fuels, and new power generation opportunities have awakened interest in power generation in the pulp and paper industry and other industries. We believe a strategic review of these issues will help favorably position the pulp and paper industry for the next century.

I. Typical integrated mill energy use and costs

	Energy used, M Btu/ton		Cost/ton, U.S. $	
	1980	1989	1980	1989
Purchased fuels				
Electricity	0.81	1.15	9.7	15.7
Fuel oil, no. 6	19.49	15.03	75.4	39.6
Total	20.30	16.18	85.1	55.3
Self-generated fuels				
Bark	4.18	3.67	...	...
Black liquor	16.82	14.11	...	...
Hydroelectric	0.28	0.41	(3.7)	(4.4)
Total	21.28	18.19	(3.7)	(4.4)
Net	41.58	34.37	81.4	50.9
Change, %	-17.2		-37.5	

Background

The pulp and paper industry ranks as the fourth largest energy consumer among the manufacturing industries in the United States, requiring about 2.3 quads annually. This currently represents 12.5% of U.S. industrial energy consumption. The industry includes approximately 390 manufacturing plants located predominantly in the Northeast, North Central, Southeast, and Pacific states.

The primary raw material consumed by the pulp and paper industry is cellulose, chiefly in the form of wood. In addition, the industry consumes quantities of clay and other inorganic fillers, starches, resins, and chemical additives which appear in the final products, as well as pulping and bleaching chemicals. Product categories include newsprint, printing and writing papers, special industrial papers, tissue papers, containerboard and boxboard, packaging papers, and building paper and board.

The production of most paper and paper board products generally follows the following sequence:

1. Pulpwood acquisition, harvesting of roundwood, and procurement of sawmill residues
2. Debarking of roundwood
3. Chipping of roundwood
4. Pulping, either chemical or mechanical
5. Pulp bleaching
6. Pulp or paperboard production, or both
7. Converting.

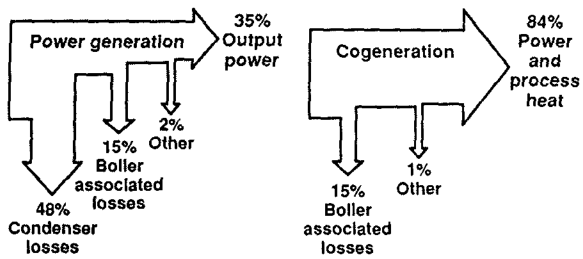
Not all of these steps are necessary for each product.

Fuels used

Purchased fuels consumed are principally oil, coal, and natural gas. The various product categories differ in their specific energy requirements for production. Nowhere does purchased electricity take on the primary energy role; it normally ranges from six to seven percent of the total energy used. Self-generated fuels currently range from

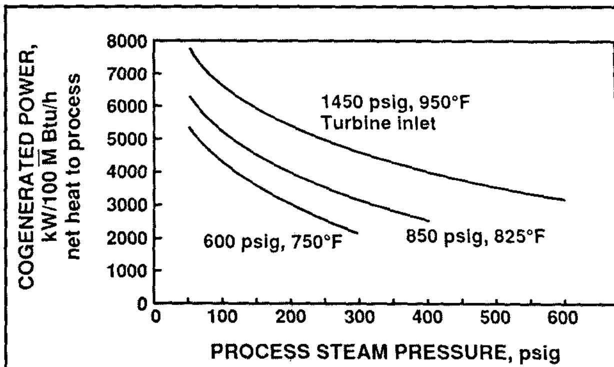
Anderson is director-energy at International Paper Co., 2 Manhattanville Rd., Purchase, N.Y. 10577-2196. Kovacik is manager-application engineering at GE Co., Bldg. 2 400, One River Rd., Schenectady, N.Y. 12345.

1. Fuel utilization effectiveness



Modern coal-fired systems.
Effectiveness on higher heating value of coal.

2. Cogeneration power with steam turbines



Average temperature of process returns and makeup is 165°F.
Power cycle credited for feedwater heating to 455°F for 1450 psig, 400°F for 850 psig, and 370°F for 600 psig systems.
Turbine efficiency, 75%.

55% to 60% of the total energy used. This compares with about 45% in 1980. Self-generated energy sources include bark, hogged fuels, and liquors, and some hydroelectric power. Except for hydroelectric power, these sources are by-products of the basic pulping process, and their use, and the steam and electricity generated from them, will continue to provide the industry's base energy requirements in the future.

Bark

The process of manufacturing pulp from wood fiber makes the bark, which is removed during the process, available as a waste material. The predominant methods of bark disposal have been land-filling and burning, where energy is often recovered from the combustion process.

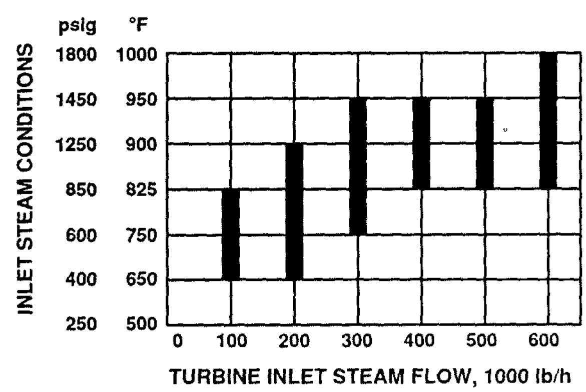
Black liquor

The spent cooking liquors from the kraft or sulfate pulping process, along with the lignin dissolved and removed from the wood, constitute a mixture which is commonly called black liquor. This mixture is separated from the pulp fiber, following the chemical cooking process, by a combination of water-washing and vacuum removal in the brownstock washing process. The resulting solution is called weak black liquor. Its concentration is raised through multiple-effect evaporators to approximately 65% solids. The black liquor is then burned in recovery boilers which perform the dual function of recovering chemicals and generating steam. The heating value of the solids varies substantially, but the average is about 6700 Btu/lb.

Energy consumption

The breakdown of energy use, by fuel type, for a typical integrated mill without natural gas is illustrated in **Table I** along with the actual costs of purchased energy. Housekeeping measures and capital improvements for energy reduction at this mill have reduced net energy used per ton by 17.2% since 1980 and the energy cost per ton

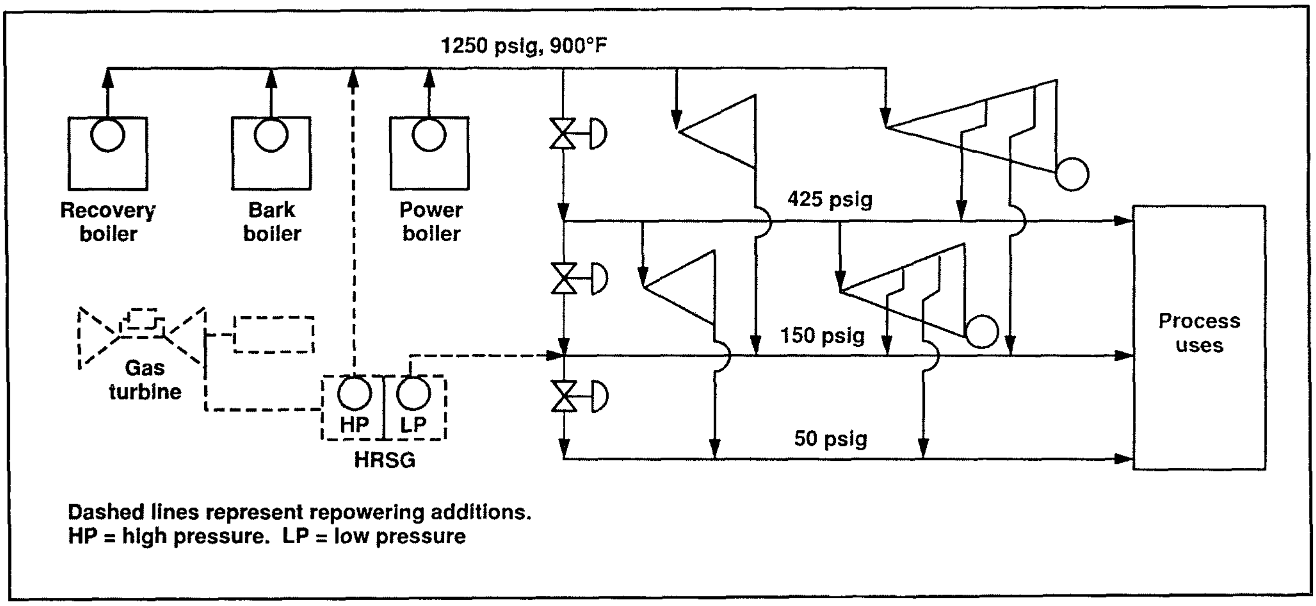
3. Range of initial steam conditions normally selected for industrial steam turbines



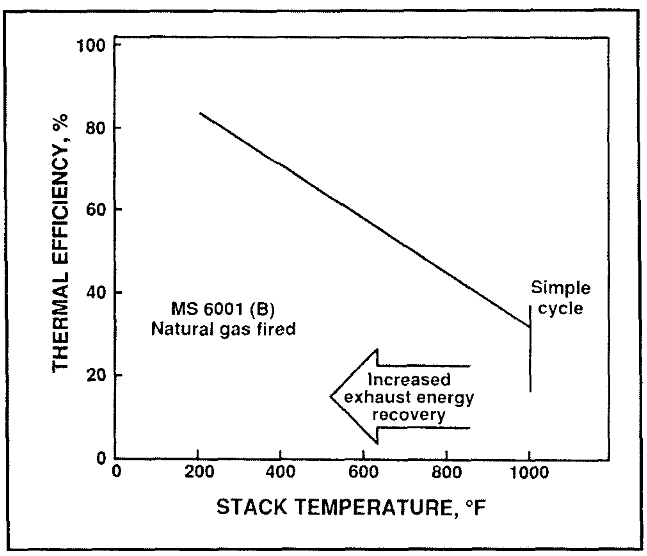
by 37.5%. Although energy reduction at this mill has been significant, it is extremely vulnerable to the fluctuating price and availability of fuel oil.

From a strategic viewpoint, this mill needs an alternative to oil such as gas or coal. Given a long-term supply of appropriately priced alternative fuel, installing cogeneration to displace purchased electricity and make the mill electrically independent becomes a viable option. Further, the possibility of building a much larger cogeneration facility and further reducing energy costs at this mill may be economically attractive if a market to sell electricity is available at an acceptable price. Although larger power sales opportunities are not a prerequisite for gas turbine-based cogeneration systems, it is in the context of such opportunities that we present much of the following material.

4. Repowering an existing pulp and paper mill



5. Thermal efficiency vs stack temperature



Steam requirements

Pulp and paper mills are complex facilities with a broad range of steam requirements. Facilities have typically been developed over many years, resulting in power plants generating steam at several pressure levels (typically 150 psig, 425 psig, 650 psig, and 1250 psig).

For most of this century, large pulp and paper mills have been designed to include power generation, typically incorporating the topping cycle. Conventional wisdom has dictated that the integration of steam turbine generators into the steam supply systems results in significant energy cost savings relative to other sources of electrical power. Cogeneration, as shown in **Fig. 1**, was the technology that provided the favorable economics. The reduction in energy losses from 65% for a typical utility to 16% for steam turbine cogeneration provided the economic incentive that justified installation.

Steam turbine cycles

In thermally optimized[1] steam turbine cogeneration cycles, steam is expanded in noncondensing or automatic-extraction noncondensing steam turbine-generators, which extract or exhaust into the process steam header(s). The fuel chargeable to power (FCP)[2] for these systems is typically in the range of 4000 Btu/kW·h to 4500 Btu/kW·h higher heating value (HHV). The influence of initial steam conditions and process steam pressure on the amount of cogenerated power per 100 million Btu/h net-heat-to-process is shown in **Fig.** 2. The increase in cogenerated power through the use of higher initial steam conditions, as well as lower process pressures, is readily apparent.

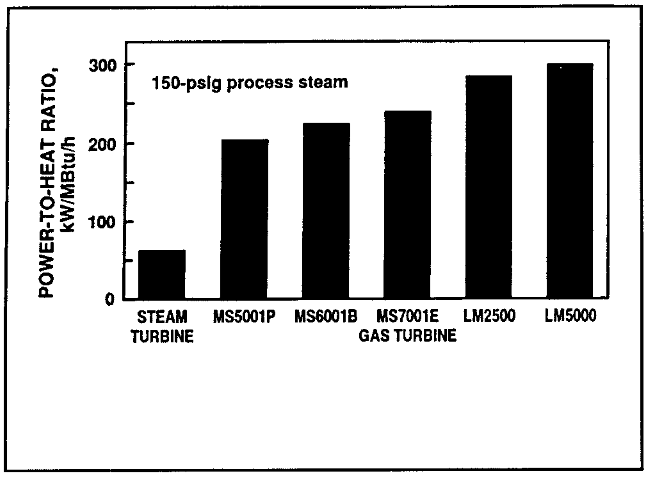
Experience has shown that the higher steam conditions can be economically justified more easily in pulp and paper mills having relatively large process steam demands. Data given in **Fig. 3** provide guidance with regard to the initial steam conditions that are normally considered for mill cogeneration applications. Higher energy costs experienced since the mid-1970s are favoring the upper portion of the bands shown in Fig. 3.

Even with the use of the most effective steam turbine cogeneration system, the amount of power that can be cogenerated per unit of heat energy delivered to process will usually not exceed about 85 kW per million Btu net-heat-supplied-to-process. This power-to-heat ratio requires the most favorable combinations of throttle steam conditions and process pressures. Typical values are

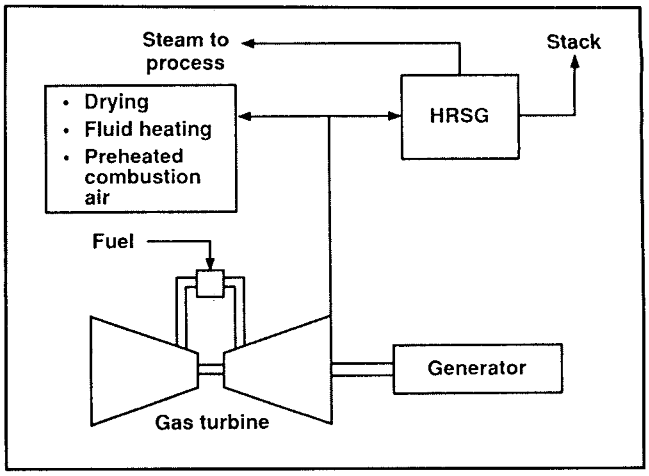
[1]Thermally optimized is defined as a cycle without condensing steam turbine power generation.

[2]FCP for a power generation option is the incremental increase in fuel divided by the net power generated relative to the alternative with which it is being compared.

6. Power to heat ratio for various cogeneration systems



7. Cycle diagram of cogeneration plant



considerably less. For example, a relatively new pulp and paper mill with 1250 psig, 900°F initial steam conditions would have a lower power-to-heat ratio of about 60 kW/MBtu for steam delivered to process at 150 psig, and steam delivered at 60 psig would yield about 73 kW/MBtu. An older mill with 850 psig, 825°F initial steam conditions would result in power-to-heat ratios of 36 kW/MBtu and 50 kW/MBtu, respectively, at process steam pressures of 150 psig and 60 psig.

The power-to-heat ratios available in most thermally optimized steam turbine cycles are not generally adequate to generate all the mill electrical requirements. Thus, a purchased power tie or condensing power generation is necessary to provide the balance of the mill power needs.

Condensing steam turbine power generation, although not necessarily energy efficient, has proven economically attractive in many pulp and paper mills. Favorable economics are usually associated with systems where:

- Condensing power is used to control purchased power demand.
- Condensing provides flexibility in process operations.
- Low-cost fuels or process by-product fuels are available.
- Adequate low-level process energy is available for a bottoming cogeneration system.
- Condensing provides the continuity of service in critical mill operations where loss of the utility tie can cause a major disruption in process operations.
- Utility-specific situations favoring power sales, particularly if low-cost fuels are available.

Gas strategy

Many large pulp and paper mills have been essentially self-sufficient in energy production due to their recovery cycle and their ability to burn waste products. Great emphasis has been placed on constructing power boilers that burn a variety of fuels. In recent years, however, circumstances developed that have encouraged the installation of gas turbines. In general, there are four reasons for the change:

1. The availability of natural gas under favorable pricing is increasing.
2. New legislation has encouraged cogeneration by nonutilities to meet the growing electrical requirements of the United States.
3. Utilities are reluctant to install new large base-load plants.
4. The large and stable consumption of steam by pulp and paper mills has coupled with their extensive experience with steam turbine cogeneration.

Many mills will have an excellent opportunity to reduce their steam and electricity costs and sell power where the market supports a sufficiently high purchase price for electricity. Replacement of a power boiler with a gas turbine and heat recovery steam generator (HRSG) (repowering) is shown in **Fig. 4**. Power needs in the Northeast and South Pacific Coast areas have offered such opportunities in recent years; the trend is expected to intensify and spread nationwide as power markets grow in the next decade.

Gas turbine and combined cycles

A gas turbine is a prime mover based on the Brayton cycle. Typical simple-cycle gas turbines will convert 30–35% of the fuel input energy into shaft power. The largest portion of the fuel is rejected as thermal energy in the gas turbine exhaust.

The improvement in overall use of energy through the recovery of turbine exhaust energy is given in **Fig. 5**. This diagram shows that the thermal efficiency improves as more exhaust energy is recovered. If effective heat recovery reduces the exhaust gas temperature to 300°F or less, the thermal efficiency is equal to, or will exceed, 77% on a high-heating-value basis.

Gas turbine cycles provide the opportunity to generate a larger power output per unit of heat required in process relative to noncondensing steam turbine cogeneration systems. The data given in **Fig. 6** suggest that gas turbines with heat recovery can provide three to four times as much power per unit of heat delivered to process relative to typical thermally-optimized steam turbine cogeneration

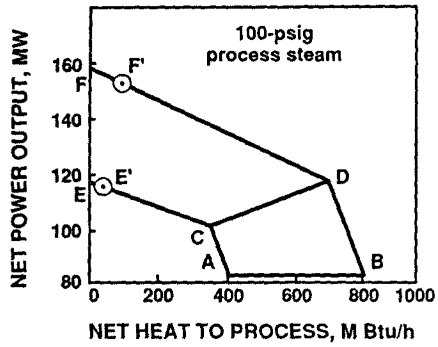
II. Steam generation and FCP with gas turbine exhaust heat boilers

Gas turbine type	*MS5001(PA)*	*MS6001(B)*	*MS7001(EA)*	*MS7001(F)*	*LM2500-PE*	*LM5000-PC*
Gas turbine model	*PG5371(PA)*	*PG6541(B)*	*PG7111(EA)*	*PG7111(F)*	*PGLM2500-PE*	*PGLM5000-FC*
ISO base rating, kW	*26,300*	*38,340*	*83,500*	*150,000*	*21,790*	*33,060*
Performance at 59°F, sea level, natural gas fuel output, kW						
Unfired	25,890	38,000	82,670	146,800	21,540	32,640
Supp. fired	25,710	37,820	82,320	145,990	21,400	32,420
Fully fired	25,430	37,530	81,800	144,780	21,220	32,080
Speed, rpm	5,100	5,100	3,600	3,600	3,600	3,600
Fuel, M̄Btu/h (HHV)	344.6	462.3	967.8	1645	236.2	356.3
Exhaust flow, lb/h	971,400	1,083,000	2,295,200	3,307,500	524,300	957,400
Exhaust temp., °F						
Unfired	906	1,007	989	1,091	992	845
Supp. fired	909	1,010	991	1,094	995	848
Fully fired	913	1,014	994	1,099	1,000	852
HRSG performance fuel, M̄Btu/h (HHV)						
Supp. fired	221.5	214.2	467.9	567.8	106.5	236.8
Fully fired	878.7	904.4	1,928.7	2,525.2	423.8	851.2

Steam conditions, psig/°F	*HRSG steam, 1000 lb/h*	*FCP GT, Btu/ kW•h*	*HRSG steam, 1000 lb/h*	*FCP GT, Btu/ kW•h*	*HRSG steam, 1000 lb/h*	*FCP GT, Btu/ kW•h*	*HRSG steam, 1000 lb/h*	*FCP, Btu/ kW•h*	*HRSG steam, 1000 lb/h*	*FCP, Btu/ kW•h*	*HRSG steam, 1000 lb/h*	*FCP, Btu/ kW•h*
Unfired												
160/371	143.4	6,650	193.2	6,060	397.5	5,930	676.0	5,670	91.5	5,860	125.4	6,300
420/655	114.4	7,240	159.0	6,420	325.5	6,300	567.0	5,910	75.0	6,190	97.3	6,820
630/755	104.4	7,560	148.0	6,610	302.0	6,500	534.0	6,020	69.6	6,360	87.3	7,100
895/830	96.2	7,870	139.4	6,800	283.5	6,690	509.0	6,130	65.4	6,520	...	...
895/830	96.2	6,360	139.4	5,920	283.5	5,690	509.0	5,440	65.4	5,650	...	...
160/371	32.3	...	27.6	...	68.2	...	84.5	...	15.5	...	...	...
1,315/905	...	...	130.8	5,920	264.5	5,700	487.0	5,430	...	...	...	...
160/371	...	...	34.3	...	83.2	...	98.1	...	...	...	...	...
1,525/955	...	...	125.8	5,920	253.5	5,720	471.5	5,450	...	...	...	...
160/371	...	...	37.8	...	90.1	...	104.4	...	...	...	...	...
Supp. fired												
420/655	301.0	5,960	338.0	5,630	722.0	5,410	1,044.0	5,350	165.4	5,420	301.5	5,540
630/755	289.5	5,980	324.5	5,670	695.0	5,420	1,004.0	5,360	159.0	5,430	290.0	5,550
895/830	281.0	6,030	315.0	5,710	676.0	5,440	977.0	5,370	154.8	5,440	282.0	5,580
1,315/905	273.5	6,100	306.5	5,770	661.0	5,430	955.0	5,380	151.2	5,450	275.5	5,580
1,525/955	269.0	6,080	301.5	5,740	651.0	5,400	941.0	5,340	149.0	5,410	271.5	5,540
Fully fired												
630/755	777.0	4,610	836.0	4,710	1,784.0	4,370	2,466.0	4,560	396.0	4,540	749.0	4,410
895/830	757.0	4,610	815.0	4,690	1,740.0	4,340	2,405.0	4,530	386.0	4,530	730.0	4,400
1,315/905	740.0	4,610	796.0	4,710	1,706.0	4,250	2,358.0	4,460	378.5	4,450	716.0	4,290
1,525/955	726.0	4,650	782.0	4,700	1,676.0	4,230	2,317.0	4,450	372.0	4,420	704.0	4,250

Gas turbines and boilers fueled with natural gas and all fuel data based on higher heating value (HHV). Unfired single-pressure boilers 92% effectiveness for SH and evaporator; supplementary fired to 1600°F, 86.8-90.5% effectiveness; fully fired to 10% excess air with 300°F stack. For two-pressure boilers, criteria of minimum 300°F stack temperature may require less than 92% low-pressure boiler effectiveness. Assumes 0% exhaust bypass stack damper leakage, 3% blowdown, 1½% radiation and unaccounted losses, and 228°F feedwater for all cases. Gas turbine inlet 4 in. H_2O, exhaust 10 in. H_2O for unfired, 14 in. H_2O supplementary fired, and 20 in. H_2O for fully fired. LM2500 and LM5000 values based on guarantee, not average engine performance. Fuel chargeable to gas turbine power assumes gas turbine credit with power house auxiliaries and equivlent 84% boiler fuel required to generate steam. Lower heating value (LHV) = 21515 Btu/lb, HHV = LHV × 1.11.

8. Performance envelope for gas turbine cogeneration system (MS 7001 EA)



Gas turbine operating at its 69°F capability, sea level site, natural gas fuel, steam injection for 42 ppmvd NO_x emission level.

Cycle A Unfired HRSG

Cycle B: Supplementary fired (1600°F) HRSG, low-pressure process steam

Cycle C: Combined cycle, unfired, two-pressure level HRSG, HP at 1250 psig, 900°F low pressure at 100 psig sat., noncondensing steam turbine-generator

Cycle D: Combined cycle, supplementary fired HRSG, steam at 1250 psig, 900°F, noncondensing steam turbine-generator

Cycle E: Same as Cycle C, but with extraction/admission condensing steam turbine-generator

Cycle F: Same as Cycle D, but with extraction/admission condensing steam turbine-generator

Process returns and makeup enter the integral 5-psgi deaerating heater at a mixed temperature of 110°F

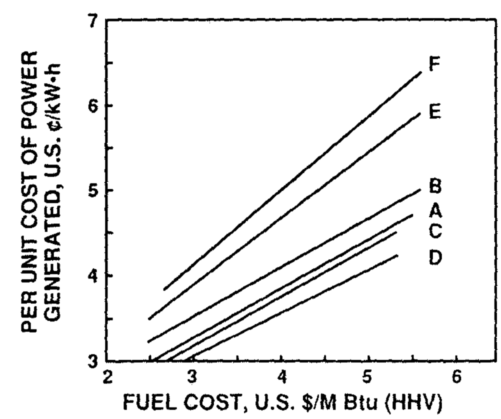
Cycles E' and F' represent minimum extraction for process at 100 psig to meet requirement of a qualifying cogeneration facility under PURPA.

III. Performance of gas turbine cogeneration cycles (MS 7001 EA)

Cycle	*A*	*B*	*C*	*D*	*E*	*F*
Net output, MW	83.3	83.1	99.1	119.1	117.9	158.8
NHP, M Btu/h	404	797	332	695	0	0
Net fuel, M Btu/h (HHV)	490	495	576	617	971	1444
FCP, Btu/kW•h (HHV)	5880	5960	5810	5180	8230	9090
Power per unit heat to process, kW/M Btu/h	206	104	298	171	NA	NA

Cycle definitions as given in Fig. 8. Net output is the total power credited to the cogeneration cycle. Net fuel includes credit for the net heat to process (NHP) at an 84% process boiler efficiency.

9. Per unit cost of power generation



Grass roots plant.
Cycles as defined in Fig. 8 and Table II.
Operation 8400 h/yr.

cycles. This characteristic, combined with a favorable FCP ratio and proven reliability, has made gas turbines with heat recovery widely accepted in applications where suitable fuels are economically available.

Gas turbine systems development in the pulp and paper industry depends upon effective use of the exhaust energy. The most common use of this energy is for steam generation in HRSGs, unfired as well as fired designs. However, the gas turbine exhaust gases can also be used as a source of energy for unfired and fired process fluid heaters and for preheated combustion air for power boilers, as well as energy for direct drying of certain mill products (**Fig.** 7).

Heat recovery steam generators

The overall FCP in a gas turbine-HRSG system is a function of the amount of energy recovered from the turbine exhaust gas. The greater the amount of energy recovered, the lower the HRSG stack temperature and the better the FCP. Thus, gas turbine-HRSG cycles should use the lowest practical feedwater temperature to the economizing section of the HRSG, within constraints imposed due to gas-side corrosion considerations. Typical values are 250–285°F for applications using sulfur-bearing fuels, and 180°F or lower if sulfur-free natural gas is available. These feedwater temperatures are in contrast to steam turbine cycles, which provide increased cogenerated power as more regenerative feedwater heating is incorporated into the cycle.

HRSG units are available in unfired, supplementary fired, and fully fired designs. The appropriate selection is established through economic evaluations of various potential configurations for the application. Estimates of HRSG steam production rates for applications based on GE gas turbine models are given in **Table II.**

Cycle design flexibility

One method of displaying the many gas turbine cogeneration options available is shown in **Fig. 8.** This diagram, based on use of the GE MS7001EA gas turbine-generator (83.5 MW ISO natural gas fired), illustrates a potential output ranging from 83 MW to about 159 MW depending upon process heat requirements and whether supplementary firing is used in the HRSG.

A summary of the MS7001EA performance, including FCP values, is given in **Table III**. The data show the more favorable FCPs for the thermally-optimized regime, area ABCD, relative to the E and F cases, which are straight power generation alternatives.

The per unit cost of power generation for the MS7001EA cycles A–F is illustrated in **Fig. 9**. The per unit costs are based on a 20% fixed charge rate and include other operating costs such as fuel, labor, and maintenance. The plant costs, not given, were based on separate stand-alone (grass roots) facilities.

Per unit costs given in Fig. 9 define two distinct performance levels. The "thermally-optimized" cogeneration cases, Cases A–D, result in per unit costs that are about 20% lower than the unfired power generation case, Case E. If the thermally-optimized cogeneration cases were considered as an addition to an existing facility, implementing a major mill expansion, or displacing new boiler capacity to replace aging equipment, the comparisons would be more dramatic since the incremental capital costs for the cogeneration systems might be 25–40% less than those used for Fig. 9. Even so, site-specific fuel and power costs, or power sales opportunities, may dictate cycles with considerable condensing power as the appropriate economic choice.

The Public Utility Regulatory Policies Act

The legislation having the greatest impact on the development of cogeneration, and particularly gas turbine-based cycles, is the Public Utility Regulatory Policies Act (PURPA). The broad objective of PURPA is to encourage conservation and the effective use of energy resources. Furthermore, PURPA includes provisions that remove obstacles to cogeneration that have evolved since the beginning of the century. These provisions state that the utility must:

- Buy power from qualifying cogeneration facilities at a rate related to the utility's avoided cost of power generation
- Provide backup power to the cogenerator at nondiscriminatory rates
- Exempt qualifying cogenerators from State and Federal regulations with regard to public utilities.

The power sales provision of PURPA is the primary factor contributing to the interest in cogeneration cycles that generate significantly more power than that required to satisfy a mill's needs for electric power. However, to derive the economic benefits associated with the sale of cogenerated power, the energy supply system configurations being evaluated must satisfy qualification criteria identified in this legislation.

PURPA qualifying standards

To distinguish new cogeneration facilities that will provide meaningful energy conservation from those that would be token facilities producing trivial amounts of useful heat or power, the Federal Energy Regulatory Commission regulations set three separate qualifying criteria: an operating standard, an efficiency standard, and an ownership criterion. The cogeneration qualifying facility criteria depend upon whether the facility uses a topping or a bottoming cycle.

The operating standard requires that a new topping-cycle facility must produce at least 5% of the total energy output as useful thermal energy. The efficiency standard, which is only applicable if oil or natural gas is used, requires that the annual electric power plus one-half the useful thermal energy must be at least 42.5% of the total natural gas and oil input (on a lower heating value basis) except that, if the thermal energy output is less than 15% of the total energy output, the efficiency requirement becomes 45%. Lastly, the ownership criterion states that a utility may not own more than 50% of a cogeneration facility.

PURPA qualification: GE units

The minimum steam demand required to qualify a facility using GE gas turbine units is given in **Table IV**. Data suggest that all combined cycles except the MS5000 can easily qualify at thermal outputs in the 5% to 8% range. The LM5000 STIG (steam-injected gas turbine) and MS5000 combined cycle need a thermal output of just over 15% to attain the 42.5% qualifying efficiency. The higher thermal output and PURPA efficiency for the LM2500 STIG is based on process use of all HRSG steam in excess of the maximum injection flow of 50,000 lb/h.

Increasing the steam delivered to process will decrease the power output and increase the PURPA efficiency relative to Table IV values. Reasonable changes in process steam pressure (50 psig) will not significantly alter the qualification conditions given.

Gas turbine cogeneration opportunities

Circumstances under which cogeneration should be considered in the pulp and paper industry include:

- Development of new mill facilities
- Major expansions to existing facilities
- Replacement of aging steam generation equipment
- Significant changes in energy costs (fuel and power)
- Power sales opportunities
- Concern with regard to the availability or reliability of alternate supplies
- Displacement of existing gas- or oil-fired, or both, boiler capacity (repowering).

New mills, major expansions to existing facilities, or replacement of aging fossil-fuel-fired boiler capacity provide ideal opportunities to evaluate gas turbine cogeneration. In these instances, a significant capital expenditure to support steam generating requirements is necessary, i.e., a "do nothing" option does not exist. A gas turbine-generator with an HRSG displacing a portion or all of the gas- or oil-fired, or both, boiler capacity requirement would represent an incremental discretionary investment. Thus, its capital cost on a U.S. $/kW basis would be less than if no mill steam generating investment was required. For example, assuming a new facility requires 500,000 lb/h of gas-fired boiler capacity at 150 psig and 50 MW, the incremental investment for a MS6001B with a supplementary-fired HRSG providing a

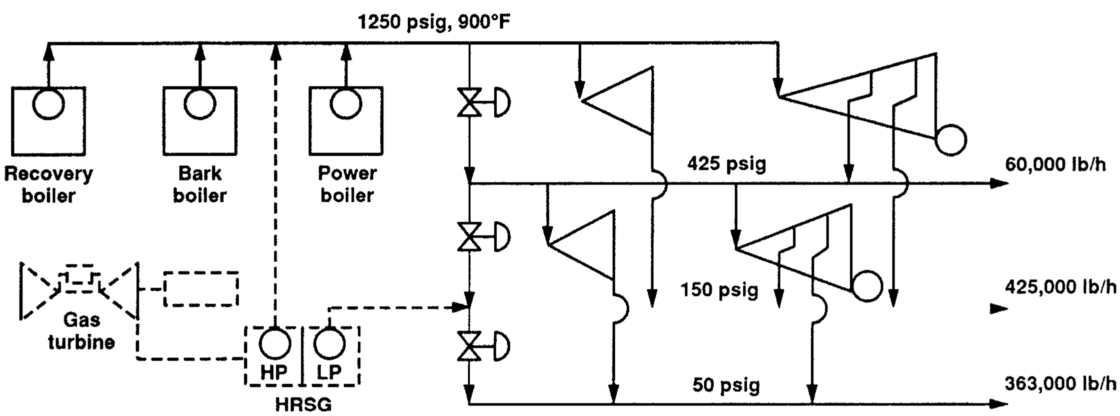
IV. Minimum steam requirements for PURPA qualifications

Gas turbine cycle	*LM 2500 Comb.*	*LM* 2500 STIG*	*LM 5000 Comb.*	*LM 5000 STIG*	*MS 5000 Comb.*	*MS 6000 Comb.*	*MS 7000EA Comb.*
Output, MW net	29.1	25.9	43.6	46.2	33.8	53.8	116.2
Fuel, M Btu/HR(HHV)	246	250	376	447	352	476	996
Steam to process, 1000 lb/h	5	35	7	29	23	14	19
Thermal output, %	5	32	5	15	17	8	5
PURPA efficiency, %	46	47	45	42.5	42.5	45	45

Sea level 60°F. 60% RH, natural gas fuel. 42 ppmvd NO_x steam injection for NO_x control. Four-inch H_2O inlet ΔP. 12-in. H_2O exhaust ΔP. unfired two pressure level HRSG. Process at 150 psig sat., 110°F average return conditions. Auxiliaries are 3% of the gross output. Steam conditions are variable. 2½ HgA condenser pressure.

*Minimum steam is 15.8K/1000 lb/h if exhaust bypass is used.

10. Repowering an existing pulp and paper mill



Alternative	Turbine power, MW			Boiler steam, 1000 lb/h		
	Gas	Steam	Total	Recovery	Bark	Power
Existing	NA	47.5	47.5	575	160	266
MS6001B	37.1	46.8	83.9	575	160	110
MS7001EA	80.9	46.0	126.9	575	109	0

portion of the required steam may be about US$ 320/kW. Installation of a separate facility with the MS6001B and supplementary-fired HRSG system may approach US$ 600/kW, making that project more difficult to justify economically.

When a mill anticipates a significant change in energy costs, the economic potential of cogeneration should be examined. This is particularly true in locations where purchased power costs may be increasing disproportionately relative to fuel. A cogeneration evaluation may suggest attractive economics even if there are not offsetting investments.

One of the greatest cogeneration opportunities in the pulp and paper industry is repowering, the displacing of existing gas/oil-fired boiler capacity with gas turbine/HRSG systems. In most applications, a gas turbine with an unfired HRSG will provide power in the 5000 Btu/kW•h to 6000 Btu/kW•h HHV range. And, the estimated total installed cost for the gas turbine-HRSG system will generally be less than a grass roots system since many of the existing supporting systems such as steam, condensate, feedwater, plant makeup, etc. will likely be adequate to serve the HRSG system.

A simplified example of repowering is given in **Fig. 10.** The solid lines show the present means by which steam is cascaded from 1250 psig to process pressures of 425 psig, 150 psig, and 50 psig. This existing system produces 47.5 MW while providing 848,000 lb/h steam for process use,

V. Repowering example energy summary

Case	*Base*	*MS6001 (B)*	*MS7001 (EA)*
Power generated, MW			
Steam	47.5	46.5	45.4
Gas	...	. 37.1	80.9
Δ aux.	Base	(0.3)	(0.6)
Net generated	47.5	83.9	126.9
Δ generation	Base	36.4	79.4
Purchased	18.8	(17.6)	(60.6)
fuel, MBtu/h (HHV)			
Power boiler	377.7	154.8	...
Bark boiler	266.1	266.1	181.2
Gas turbine	...	451.8	948.0
FCP, Btu/kW•h (HHV)	Base	6290	6115

VI. Repowering example economic analysis, U.S. $ million

Case	*Base*	*MS6001 (B)*	*MS7001 (EA)*
Annual operating cost summary			
Fuel			
Gas	7.55	12.13	18.95
Wood and gas	3.73	3.73	2.54
Power	7.52	(7.04)	(24.24)
Makeup	Base	0.09	0.20
Maintenance	Base	0.48	0.81
	18.80	9.39	(1.74)
Benefit	Base	9.41	20.54
Estimated investment	...	17.0	29.0
Gross payout/year	Base	1.8	1.4

Operation 8000/h/yr. Natural gas at $2.50/million Btu (HHV): wood/gas at $1.75/million Btu (HHV). Power value U.S. ¢5/kW•h. Demineralized makeup is $4.00/1000 gal. Maintenance is 3% of estimated investment.

and 153,000 lb/h for power plant use, including feedwater heating. Of the total steam production, a power boiler produces 266,000 lb/h, about 27% of the total steam required.

Shown in dashed lines is the addition of a gas turbine generator with an unfired multiple-pressure-level HRSG. The natural-gas-fired turbine options considered include the MS6001B (38.34 MW ISO) and MS7001EA (83.5 MW ISO). The summary of performance for these options is given in the tabulation at the bottom of Fig. 10. The reduction in the output of the existing steam turbine-generator units is due primarily to the loss in feedwater heating capability resulting from addition of the HRSG with its integral deaerating section.

An energy summary for this example is given in **Table V**. The data show that the net increase in the mill power generation with the MS6000 is 36.4 MW, and 79.4 MW when repowering with the MS7000. The tabulation also suggests that a power sales agreement is necessary to accommodate generation in excess of plant needs. The FCP values, developed from the generation and fuel summary, show the MS7001EA to have superior thermal performance. However, since a portion of the MS7001EA HRSG steam is displacing wood in the bark boiler, its economic impact is less than displacing natural-gas-fired capacity.

A simplified economic summary for the example presented in Fig. 10 is given in **Table VI**. The economic benefit for each alternative is expressed as its gross payout period (GPO) and is defined as the estimated investment cost for the alternative divided by its annual operating cost benefit relative to the Base Case.

The GPO values given in Table VI are developed using the conditions noted in the footnotes. The results indicate a GPO of 1.8 years for the MS6001B system and 1.4 years for the MS7001EA, with HRSG based on the fuel and power values assumed. If the value of power is reduced from the 5 cents/kW•h used in Table VI to 4 cents/kW•h, the GPOs are still a respectable 2.5 years for the MS6001B and 2.1 years for the MS7001EA systems.

Conclusion

We have attempted to lend technical and economic perspective to the opportunities associated with the use of gas turbine cogeneration systems in the pulp and paper industry to meet the growing electrical needs of the United States in the next decade. By no means has it dealt with the problems and difficulties associated with implementing such projects.

At this point in time, cogeneration in the pulp and paper industry can be characterized as follows:

- Markets to sell electricity are developing due mainly to the federal impetus to encourage nonutility power generation.
- Pulp and paper mills typically have large energy requirements and represent ideal steam hosts for cogeneration facilities.
- Gas turbine technology has evolved to the point where it offers sufficient reliability and flexibility to significantly improve upon steam-cycle economics typically used in the industry.
- Gas suppliers are becoming knowledgeable and interested in supplying fuel under contracts that support third-party-financed projects.
- In cases where natural gas will replace residual oil or coal, substantial improvements in ambient air quality for sulfur dioxide and particulates are possible. At some mills, improvement in air quality may be a prerequisite for obtaining an air license or increasing production. In addition, gas-fired cogeneration may also eliminate the need for switching or committing significant capital for emissions control of existing power boilers.□

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