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GE Power Generation

Performance and Economic Considerations of Repowering Steam Power Plants

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PERFORMANCE AND ECONOMIC CONSIDERATIONS OF REPOWERING STEAM POWER PLANTS

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ABSTRACT

Repowering is broadly defined as an addition to or replacement of existing power plant equipment, retaining serviceable permitted components to improve generation economics, extend life, improve environmental performance, enhance operability and maintainability, and more effectively use an existing site. The most common form of repowering uses a gas turbine whose exhaust is used either as preheated combustion air, energy for feedwater heating or the displacement of steam from a fossil fuel fired boiler. Using the gas turbine exhaust as the steam supply in a conventional steam cycle results in the greatest increase in system output, most improved thermal efficiency and the greatest reduction in environmental emissions relative to the other available repowering options. Repowering may be an economically viable option at sites fueled with natural gas and/or distillate oil, or coal or other solid or less desirable liquid fuels if a gasification system is included.

This paper discusses the technical and economic aspects of available gas turbine-based repowering options focusing primarily on the steam displacement, or "heat recovery repowering," alternative. Included are performance and operating characteristics as well as an example illustrating the economic merit of this technology. The environmental benefits of repowering and their impact on the generation systems planning process in regions where environmental externalities are included in least cost planning evaluations are also illustrated.

INTRODUCTION

Gas turbines have been widely used in both utility and industrial applications as proven, reliable prime movers. Most base and intermediate load applications in the utility industry have been based on the installation of combined-cycle (STAG) systems where the gas and steam cycles are optimized to yield maximum thermal efficiency, which is usually economically attractive relative to other utility options.

However, gas turbines can also be integrated into existing conventional steam power plants yielding significant increases in power output while improving the plant heat rate. These performance enhancements are realized with a major reduction in environmental emissions, an increasing global utility concern. Furthermore, repowering an existing steam power plant can be an attractive consideration in areas where power plant siting is a difficult issue.

This paper will briefly review the technical and economic considerations of three gas turbine-based repowering options. In addition, the environmental benefits available through the use of repowering in the integrated resource planning process is illustrated.

REPOWERING EXPERIENCE

Combined-cycle repowering has been used to enhance the performance of existing steam plants since gas turbines were introduced to electric utilities in 1949. The first gas turbine in electric utility service was used to repower a feedwater heating system in the Oklahoma Gas and Electric Company Belle Isle Station. In the 1950s, this application was followed by other similar repowering installations and one boiler repowering installation in which the gas turbine exhaust gas was supplied to an existing boiler windbox as combustion air. The first heat recovery combined-cycle repowering system was installed in 1960 on the Community Public

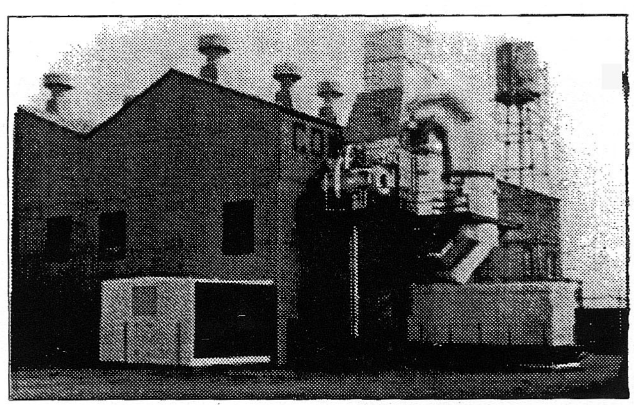

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Figure 1. Repowering System at Community Public Service Co., Lordsburg, New Mexico

Service, Lordsburg, NM, station pictured in Figure 1. An 8 MW non-reheat steam turbine was repowered by a 12 MW GE MS5001 K gas turbine in this installation.

A modern heat recovery combined-cycle repowering installation is shown in Figure 2 in which two 225 MW heat recovery combined-cycle systems replace two 60 MW non-reheat conventional steam units at the Virginia Power Chesterfield Station. In this installation, the power boilers and non-reheat steam turbines were replaced but the permitted condenser cooling water system was retained. This is a modern gas fired reheat heat recovery combined-cycle system that includes the GE MS7001F high technology gas turbine. It increased the generation approximately four times without exceeding the capacity of the existing cooling water system and increased the thermal efficiency to 50% (LHV). The first unit entered service in June 1990 and the second unit in April 1992. Thus, two coal-fired units, which had been previously retired because of economic and environmental reasons, were converted to modern combined-cycle units with outstanding generation economics and environmental performance.

While the earliest combined-cycle systems were small modifications to conventional steam plants which resulted in small improvements in efficiency, the heat recovery combined cycle has been universally recognized as the most economical configuration because of its modest installed cost, high thermal efficiency and minimum environmental impact. Therefore, this repowering approach is predominant in utility environments where large capacity additions are required to satisfy growing electrical system needs.

A summary of General Electric repowering experience is given in Table 1.

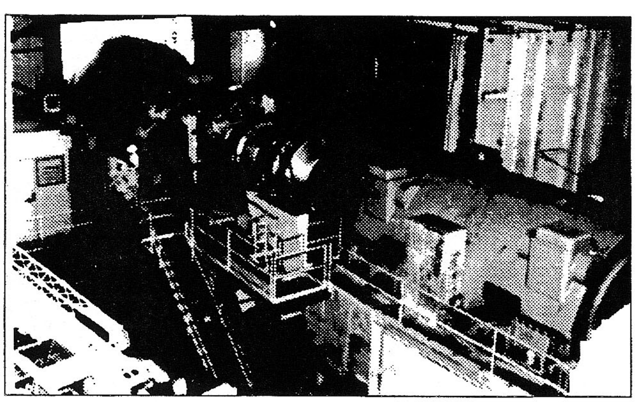

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Figure 2. Virginia Power Chesterfield Station

REPOWERING OPTIONS

Repowering involves the addition of a new gas turbine and the utilization of the gas turbine exhaust heat to improve the productivity of an existing steam power plant. There are three potential repowering options:

- Feedwater heater repowering
- Boiler windbox repowering
- Heat recovery repowering

The repowering options can increase the base plant output typically between 30% to 200% with heat rate improvements in the 5% to 40% range. The gains that can be realized are primarily a function of the repowering options selected and the size and configuration of the system being repowered.

Feedwater Heater Repowering

In a fossil steam plant, approximately 20% to 30% of the throttle steam flow is typically used for feedwater heating. If the feedwater heating duty was supplied by the gas turbine exhaust energy, then additional steam would be available for passing through the entire length of the steam turbine. In practice, the amount of additional steam passing ability is limited by the exhaust loading of the steam turbine, the heat rejection duty of the condenser or cooling towers and/or the site license discharge limits. A typical cycle diagram of a feedwater heater repowering system is presented in Figure 3. The gas turbine is used to heat feedwater in the economizer before the feedwater enters the boiler. Feedwater to the economizer can be taken from the condenser or following any combination of heaters. The greatest improvement in cycle heat rate occurs if all existing feedwater heaters are displaced.

Boiler Windbox Repowering

Boiler windbox repowering systems utilize gas turbine exhaust gas as preheated combustion air in the existing boiler. In this application, the hot, oxygen-rich gas turbine exhaust gas provides the function of the forced draft fan and air heater. The heated combustion air reduces the boiler fuel requirements. A cycle diagram of a boiler repowering system is presented in Figure 4.

Windbox repowering displaces the air preheater and would result in a high stack gas temperature if no modifications of the boiler heat recovery sections were made. In most instances, additional economizer surface will be added to the boiler, transferring this duty from the steam turbine extraction cycle to the boiler, in order to

Table 1
REPOWERING EXPERIENCE

Owner	Station	System Type	Gas Turbine No. Model	Gas Turbine Rating (MW)	Comb. Cycle Rating (MW)	Commercial Operation Year
Oklahoma Gas & Electric	Belle Isle	Feedwater Heating	1-MS3001	3.5	40	1949
Oklahoma Gas & Electric	Belle Isle	Feedwater Heating	1-MS3001	3.5	40	1952
West Texas Utilities	Rio Pecos	Boiler	1-MS3001	5.0	35	1954
Western Power	Liberal, KS	Feedwater Heating	1-MS5001K	12.0	65	1961
Community Public Service	Lordsburg, NM	Heat Recovery	1-MS5001K	12.0	20	1961
Wheatland Electric Coop.	Garden City, KS	Heat Recovery	1-MS5001L	14.0	21	1967
Carolina Power & Light	Cape Fear, NC	Heat Recovery	4-MS5001LA	64.0	90	1969
South Carolina Electric & Gas	Parr	Heat Recovery	4-MS5001M	68.0	128	1971
China Light & Power	Hok Un, Hong Kong	Heat Recovery	1-MS5001M	17.0	25	1972
Dow Chemical Co.	Sarnia, Ontario	Heat Recovery	2-MS7001B	102.0	120	1972
Gulf Oil Company	Port Arthur, TX	Boiler	1-MS5001N	23.0	23	1974
Citizen Utilities	Kauia, HA	Heat Recovery	2-MS5001N	46.0	70	1978
Anchorage, AK	Anchorage, AK	Heat Recovery	1-MS7001E	71.0	105	1979
Dow Chemical Co.	Freeport, TX	Heat Recovery	3-MS7001E	213.0	260	1982
Gaylord Container	Antioch, CA	Heat Recovery	1-MS6001A	36.0	42	1983
Virginia Power	Chesterfield	Heat Recovery	1-MS7001F	150.0	225	1990
Virginia Power	Chesterfield	Heat Recovery	1-MS7001F	150.0	225	1992
City of Vero Beach	Vero Beach, FL	Heat Recovery	1-MS6001B	38.0	57	1992
LA DWP	Harbor, CA	Heat Recovery	2-MS7001EA	166.0	249	1993
Imperial Irrigation	El Centro, CA	Heat Recovery	1-MS7001EA	83.0	124	1994

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arrive at a reasonable stack gas temperature for the repowered configuration.

Additional issues in this form of repowering include the quantity of gas turbine exhaust flow relative to boiler needs, the exhaust pressure losses imposed on the gas turbine, and possible steam system derating due to the reduced oxygen content from turbine exhaust gases relative to ambient air.

Heat Recovery Repowering

Heat recovery repowering systems are the most common application of repowering. These systems utilize gas turbine exhaust energy to generate steam in a heat recovery steam generator (HRSG), thus displacing the power boiler in the existing steam plant. Figure 5 illustrates a single throttle pressure non-reheat cycle in which all of the existing steam cycle feedwater heaters are utilized. Other cycles can be designed for increased efficiency using two- or three-pressure HRSG configurations with and without feedwater heaters. The impact of various non-reheat cycle options on the repowered configuration heat rate is given in Figure 6.

The high exhaust temperature of advanced technology gas turbines such as the MS7001FA makes repowering a reheat steam turbine an economically viable option. Figure 7 shows a simplified schematic of such an option using a three pressure level reheat HRSG, an option receiving considerable attention as utilities enhance use of existing sites. The effect of other reheat HRSG options on the repowered cycle heat rate is illustrated in Figure 8.

The multi-pressure combined-cycle system shown in Figure 7 can be accommodated by existing steam turbines that have multi-flow low-pressure sections since the crossover pipe from the intermediate-pressure section to the low-pressure section can be readily modified to accept the low-pressure steam admission. The

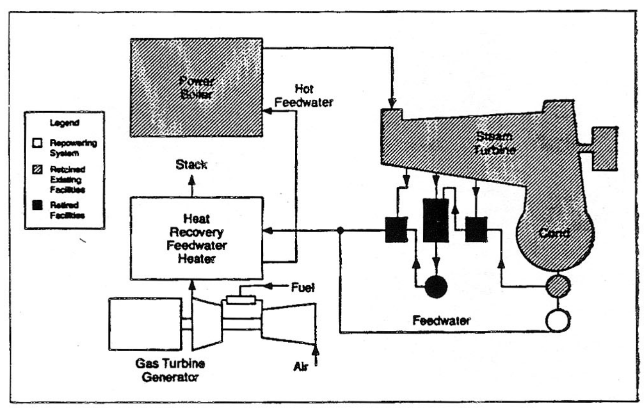

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Figure 3. Feedwater heater repowering non-reheat steam cycle

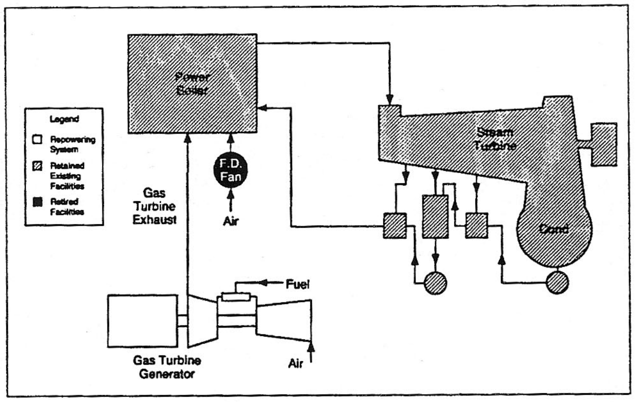

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Figure 4. Boiler windbox repowering non-reheat steam cycle

intermediate-pressure steam is admitted to the cold reheat piping which is part of the repowering system. If the economic evaluation requires a lower cost system, it can be provided by a two- or single-pressure system with higher heat rate.

Since combined cycles achieve highest efficiency with no extraction feedwater heaters and multiple low-pressure admissions, the throttle flow of the repowered steam turbine must be reduced relative to its design to maintain the same exhaust flow and heat rejection to the condenser cooling water. Further, the pressure drop between the HRSG superheater discharge and the steam turbine nozzle should be minimized for highest combined-cycle efficiency. Therefore, the repowered steam turbine should operate with valves open in a sliding pressure mode. Since the throttle flow is reduced about 25%-30% to maintain the design condenser flow, the steam pressure would be similarly decreased. Since the combined-cycle heat rate is relatively insensitive to steam pressure, as shown in Figure 8, the reduced steam pressure does not significantly increase the plant heat rate. Economics may justify steam turbine modifications to improve efficiency in some applications.

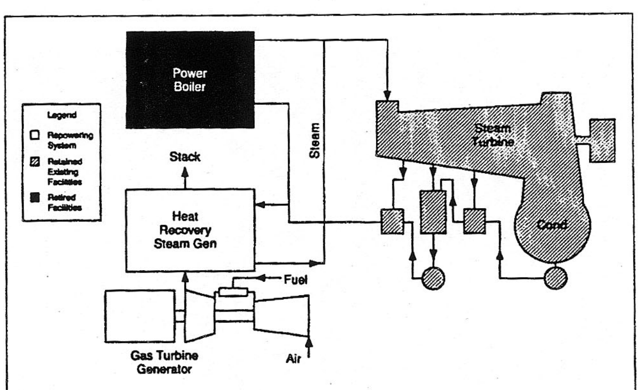

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Figure 5. Heat recovery repowering non-reheat steam cycle

Table 2 illustrates typical power output and net heat rate changes for each repowering option. The performance change is application specific and depends on the match of the new gas turbine with the existing power plant. Because heat recovery repowering leads to the largest improvements in net plant output and heat rate, most of the industry focus today is on this repowering approach.

SYSTEM SELECTION AND PERFORMANCE

The selection of the most economic repowered configuration for a specific application is dependent upon many factors. These include:

Fuel	Natural Gas Light Distillate Oil Coal
Duty Cycle	Base Load Mid-Range Daily Start-Stop
Steam Plant	Non-reheat Reheat Turbine Size Type of Cooling Cooling Water Temperature
Environmental Requirements	Emissions Thermal Discharge
Economic Factors	Fuel Cost Interest Rate Fixed Charge Rate Life of Plant

Examples of heat recovery repowering systems illustrating some of the above application criteria considering use of larger GE gas turbine generators are presented in Tables 3 through 6. These tables present repowering systems that form the highest efficiency combined cycle. These examples are based on matching the heat

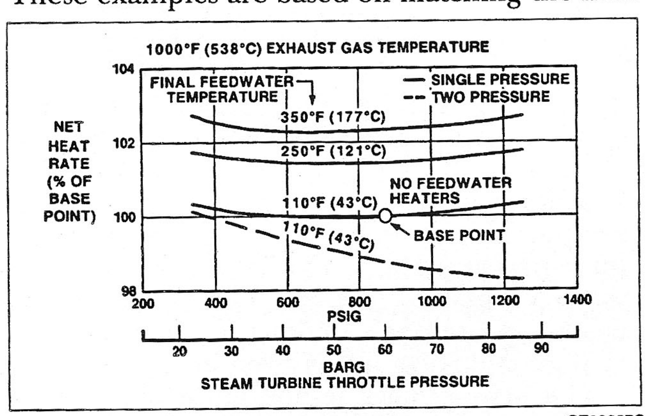

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Figure 6. Non-reheat heat recovery combined cycle

Table 2 TYPICAL REPOWERING PERFORMANCE CHANGES		
Repowering Type	% MW Increase	Heat Rate Decrease
Feedwater Heating (FWH)	40%	10%
Boiler Windbox (BW)	40%	5%-10%
Heat Recovery (HRSG)	200%	30%

rejection to the condenser cooling water system before and after repowering. The curves in Figure 6 and 8 can be applied to determine relative performance of less efficient, but lower cost repowering systems.

Repowering examples for natural gas fueled applications of heat recovery repowering of non-reheat steam plants are presented in Table 3. These systems use a two-pressure steam cycle with feedwater deaeration in an integral deaerator on the HRSG and retirement of all existing feedwater heaters. The capacity of the steam plants ranges from 38 MW to 158 MW and the efficiency of the combined cycles ranges from 43.6% HHV (48.4% LHV) to 47% HHV (52.2% LHV).

Table 4 presents potential repowered plant performance for existing reheat steam plants ranging from 48 MW to 304 MW. These plants can be repowered using high technology gas turbines, such as the GE MS6001FA (60Hz), MS7001FA (60Hz), or MS9001FA (50 Hz), which have a sufficiently high exhaust gas temperature to effectively accommodate an existing reheat steam cycle. These systems include three-pressure steam cycles, all feedwater heaters are retired and heat rejection to cooling water is not changed. The repowered cycle net thermal efficiencies are 47.7% HHV (53% LHV).

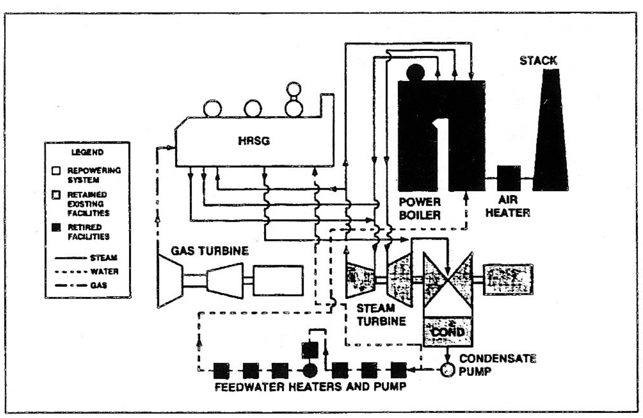

Figure 7. Reheat heat recovery repowering

The Coolwater Project demonstrated the technical feasibility of the integrated gasification combined cycle (IGCC) for Power Generation. This was a 120 MW IGCC system with one GE MS7001E gas turbine and oxygen blown Texaco gasifier that operated reliably on the Southern California Edison System for five years. With today's high technology MS7001FA (60 Hz) and MS9001FA (50 Hz) gas turbines, these systems can achieve high thermal efficiency with attractive environmental performance.

Table 5 presents data on candidate systems for repowering by an IGCC repowering system with an entrained flow gasifier in which the gas is cooled to the cleanup temperature by a water quench system. This is the lowest cost system with the least integration between the gasifier and the combined cycle. It can achieve attractive generation economics providing an environmentally clean coal-fired power plant.

The efficiency of the IGCC repowered plant can be improved by integrating the syngas cooler with the combined-cycle system. The fuel gas is cooled by generating steam which is used in the combined cycle for power generation. Table 6 presents data for such IGCC repowering systems with oxygen blown, entrained flow gasifiers. These systems require a somewhat larger steam turbine than the quench gasifier systems to achieve optimum thermal efficiency. These systems can achieve coal to electric thermal efficiencies of 42%-43% HHV (43.7%-44.7%LHV) with excellent environmental performance including NOx less than 25 ppmvd at 15% oxygen, 95%-99% sulfur removal and non-hazardous, non-leachable slag.

The development of repowered cycles can have limitations since gas turbines are available in discrete size ratings. The "match" or "fit" of a specific gas turbine model with its HRSG to the existing steam turbine being considered for repowering has a bearing on the overall results. If a gas turbine with an unfired HRSG unit provides less steam than that required by the existing steam turbine generator, supplementary firing the oxygen rich, high-temperature turbine exhaust gas can provide additional capacity to more fully load the steam turbine. And this capacity is usually provided at a heat rate that is about 10% better than the original steam cycle full load heat rate. This is primarily due to the high efficiency of supplementary firing, essentially 100% based on the lower heating value of the HRSG burner fuel. Thus, a supplemantary fired repowering option can provide effective spinning reserve capacity to a utility system.

Supplemental firing is dictated by the applica-

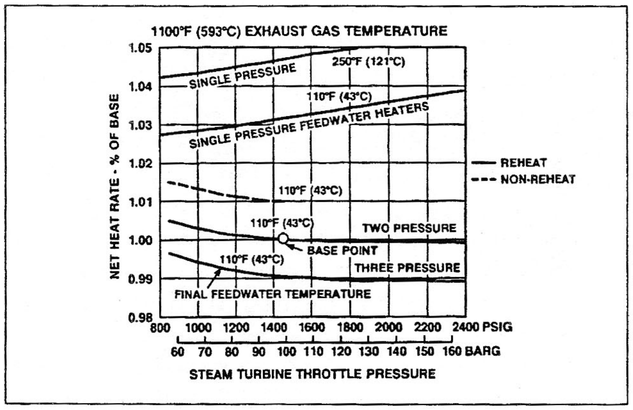

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Figure 8. Heat recovery combined-cycle steam pressure effect on heat rate

tion and may be used continuously or only during peak load periods. If used continuously, the HRSG design will include adequate heat transfer surface area to efficiently extract the available thermal energy. If used for peaking duty, the HRSG design surface can be sized for unfired operation, but when supplementary fired, the energy recovery efficiency is slightly compromised. For peaking duty, the efficiency effect is offset by savings in capital investment cost resulting in an incremental cost per incremental kW output of about 300 $/kW. The incremental heat rates are in the 10,000 Btu/kWh (10,550 kJ/kWh) (HHV) range, which is competitive with new simple cycle gas turbines for peaking duty.

When the conventional gas turbine-HRSG steam production exceeds the steam turbine exhaust flow capability, the extra steam may be used to power augment the gas turbine power output, if that option exists. The power augmentation steam expands in the gas turbine and produces additional power output. Additional gas turbine fuel is needed to heat the steam from the inlet conditions, typically 300 psig/500 F (20.7 bars/260 C), to the average gas turbine firing temperature of 2000 F to 2300 F(1093 C to 1260 C). The incremental heat rate of the gas turbine when steam augmented is in the range of 6000 Btu/kWh (6330 kJ/kWh)HHV. Thus, power augmentation is economically attractive when excess steam is available. A simplified diagram illustrating the various "fit" issues is given in Figure 9.

In summary, candidate steam turbines for repowering provide less cycle design flexibility than new combined cycles. However, HRSG design options, supplemental firing, gas turbine power augmentation and utilization of existing feedwater heaters provide flexibility to the plant

Table 3
NON-REHEAT HEAT RECOVERY REPOWERING SYSTEM EXAMPLES

Conventional Steam Plant							Repowered System Performance					
							Gas Turbine		Combined Cycle (Net)			
Net Output (MW)	Freq. (Hz)	η_{TH} (1)% (HHV/ LHV)	Exhaust Flow 10³ lb/hr	Exhaust Flow 10³ kg/hr	Heat Rejection (2) 10⁶ Btu/hr	Heat Rejection (2) 10⁶ kJ/hr	No. Model	Output (MW)	Net Output (MW)	η_{TH} (1)% (HHV/ LHV)	Heat Rejection (2) 10⁶ Btu/hr	Heat Rejection (2) 10⁶ kJ/hr
41	50/60	33.0/36.6	256	116	232	245	1-MS6001FA	68.9	102.0	44.9/49.8	232	245
57	60	33.3/37.0	350	159	317	334	1-MS7001EA	82.5	123.1	43.2/48.0	317	334
76	60	33.5/37.2	464	211	420	443	1-MS7001EC	114.2	168.0	45.0/50.0	420	443
93	60	33.5/37.2	573	260	519	548	1-MS7001FA	164.3	239.7	46.8/52.0	519	548
114	60	33.6/37.3	696	316	629	664	2-MS7001EA	165.0	247.3	43.4/48.2	629	664
79	50	33.5/37.2	485	220	439	463	1-MS9001E	122.7	180.3	44.5/49.4	439	463
105	50	33.6/37.3	643	292	581	613	1-MS9001EC	166.6	245.4	45.6/50.6	581	613
128	50	33.6/37.3	781	354	705	744	1-MS9001FA	222.6	329.1	46.7/51.8	705	744
159	50	33.7/37.4	968	439	873	921	2-MS9001E	245.4	362.1	44.7/49.6	873	921

Notes:
1. Natural Gas Fuel (HHV/LHV = 1.11)
2. Heat Rejection to Cooling Water From Condenser
3. Ambient Air Conditions: Temperature - 59 F (15 C)
Pressure - 14.7 PSIA (1.013 bar)
4. Steam Turbine Exhaust Pressure - 1.5 in. HgA (38.1 MM HgA)
5. Unfired HRSG, Two-Pressure Non-Reheat Steam Cycle
6. Net Output Based on Once Through Cooling System
7. Estimated, Actual Performance Will Depend on Condition of Repowered Equipment

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Table 4
REHEAT HEAT RECOVERY REPOWERING SYSTEM EXAMPLES

Conventional Steam Plant							Repowered System Performance (5)					
							Gas Turbine		Combined Cycle (Net)			
			Exhaust Flow		Heat Rejection (2)						Heat Rejection (2)	
Net Output (MW)	Freq. (Hz)	η_{TH} (1)% (HHV/LHV)	10^3 lb/hr	10^3 kg/hr	10^6 Btu/hr	10^6 kJ/hr	No. Model	Output (MW)	Net Output (MW)	η_{TH} (1)% (HHV/LHV)	10^6 Btu/hr	10^6 kJ/hr
49	50/60	35.5/39.4	252	114	250	264	1-MS6001FA	68.9	104.2	45.8/50.8	250	264
105	50/60	36.5/40.5	514	233	507	535	2-MS6001FA	137.8	210.8	46.3/51.4	507	535
92	60	36.4/40.4	457	207	452	477	1-MS7001EC	114.2	171.4	45.9/51.0	452	477
178	60	37.2/41.3	860	390	848	895	2-MS7001EC	228.4	344.1	46.1/51.2	848	895
115	60	36.5/40.5	565	256	558	588	1-MS7001FA	164.3	244.4	47.7/53.0	558	588
235	60	37.3/41.4	1120	508	1104	1164	2-MS7001FA	328.6	490.1	47.9/53.2	1104	1164
129	50	36.8/40.8	633	287	625	659	1-MS9001EC	166.6	250.3	46.5/51.6	625	659
255	50	37.4/41.5	1213	550	1194	1260	2-MS9001EC	333.2	503.4	46.8/51.9	1194	1260
159	50	36.9/41.0	769	349	758	800	1-MS9001FA	222.6	335.4	47.6/52.8	758	800
314	50	38.0/42.2	1482	672	1457	1537	2-MS9001FA	445.2	673.8	47.8/53.0	1457	1537

Notes:
1. Natural Gas Fuel (HHV/LHV = 1.11)
2. Heat Rejection to Cooling Water From Condenser
3. Ambient Air Conditions: Temperature - 59 F (15 C)
Pressure - 14.7 PSIA (1.013 bar)
4. Steam Turbine Exhaust Pressure - 1.5 in. HgA (38.1 MM HgA)
5. Unfired HRSG, Three-Pressure Reheat Steam Cycle
6. Net Output Based on Once Through Cooling System
7. Estimated,Actual Performance Will Depend on Condition of Repowered Equipment

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design and operation. The plant heat rate and capital cost are rather constant over a broad range of steam turbine sizes relative to the gas turbine size. Each repowering candidate unit and plant has its own unique nuances. Thus, it is necessary to conduct application specific conceptual thermal cycle design and plant cost feasibility analysis to help prioritize the repowering candidates and integrate their planning with other generation alternatives.

CONTROLS AND OPERATION

A modern heat recovery repowering system would be equipped with a distributed control system (DCS) to coordinate the components and auxiliaries. Figure 10 shows a typical architecture for such a distributed control. Most convenient operation of the system is achieved when the existing steam turbine and plant auxiliaries are integrated into the DCS. An interface unit would be required in most cases to convert the control and instrumentation signals for compatibility with DCS.

Figure 11 presents a system control diagram for a repowered reheat steam turbine using a three-pressure reheat repowering system. For convenience in starting and operation, a bypass to the condenser is desirable for each steam supply to the turbine. The low-pressure system requires the addition of a stop and control valve on the system turbine admission and an initial pressure control. It is desirable also to convert the main steam throttle control to an initial pressure control so that the steam turbine operates in the following mode after its generator is synchronized.

A heat recovery combined cycle can be started, stopped and operated by a minimum number of control room operators. A fully automated system can be controlled by one control

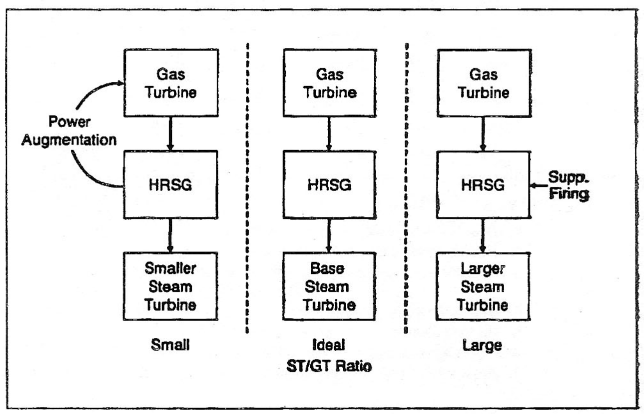

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Figure 9. Gas turbine/HRSG repowering–application flexibility

Table 5
COAL-FIRED IGCC HEAT RECOVERY REPOWERING SYSTEMS QUENCH GASIFER

Conventional Steam Plant							Repowered System Performance (7)					
							Gas Turbine		Net IGCC Plant Performance			
			Exhaust Flow		Heat Rejection (2)						Heat Rejection (2)	
Net Output (MW)	Freq. (Hz)	η_{TH} (1)% (HHV)	10^3 lb/hr	10^3 kg/hr	10^6 Btu/hr	10^6 kJ/hr	No. Model	Output (MW)	Net Output (MW)	η_{TH} (1)% (HHV)	10^6 Btu/hr	10^6 kJ/hr
44	50/60	33.8	227	103	225	237	1-MS6001FA	90	114.6	35.0	225	237
80	60	34.5	408	185	403	425	1-MS7001EC	130	167.4	35.4	403	425
120	60	34.7	598	271	590	622	1-MS7001FA	192	257.8	37.1	590	622
146	60	35.1	728	330	718	758	2-MS7001EC	260	335.8	35.5	718	758
242	60	35.5	1189	539	1171	1235	2-MS7001FA	384	517.0	37.2	1171	1235
108	50	34.7	541	245	534	563	1-MS9001EC	190	245.4	35.5	534	563
168	50	35.3	830	377	819	864	1-MS9001FA	275	369.3	36.9	819	864
210	50	35.4	1033	469	1018	1074	2-MS9001EC	380	492.3	35.6	1018	1074
331	50	36.1	1595	723	1568	1654	2-MS9001FA	550	740.5	37.0	1568	1654

Notes:
1. Coal Fuel - Hydrogen Loss = 3.6%
2. Heat Rejection to Cooling Water From Condenser
3. Ambient Air Conditions: Temperature - 59 F (15 C)
   Pressure - 14.7 PSIA (1.012 bar)
4. Steam Turbine Exhaust Pressure - 1.5 in. HgA (38.1 MM HgA)
5. Unfired HRSG
6. Net Output Based on Once Through Cooling System
7. Estimated, Actual Performance Will Depend on Site Specific Repowered Equipment and Coal

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Table 6
COAL-FIRED IGCC HEAT RECOVERY REPOWERING SYSTEMS GASIFER WITH HEAT RECOVERY

Conventional Steam Plant							Repowered System Performance (7)					
							Gas Turbine		Net IGCC Plant Performance			
			Exhaust Flow		Heat Rejection (2)						Heat Rejection (2)	
Net Output (MW)	Freq. (Hz)	η_{TH} (1)% (HHV)	10^3 lb/hr	10^3 kg/hr	10^6 Btu/hr	10^6 kJ/hr	No. Model	Output (MW)	Net Output (MW)	η_{TH} (1)% (HHV)	10^6 Btu/hr	10^6 kJ/hr
50	50/60	33.8	256	116	254	268	1-MS6001FA	90	118.9	39.6	254	268
90	60	34.5	458	208	452	477	1-MS7001EC	130	173.5	40.0	452	477
131	60	34.7	652	296	643	678	1-MS7001FA	192	265.8	41.8	643	678
163	60	35.1	813	369	802	846	2-MS7001EC	260	347.8	40.1	802	846
264	60	35.5	1296	588	1276	1346	2-MS7001FA	384	533.0	41.9	1276	1346
121	50	34.7	605	274	597	630	1-MS9001EC	190	254.2	40.1	597	630
183	50	35.3	906	411	894	943	1-MS9001FA	275	380.9	41.5	894	943
234	50	35.4	1153	523	1136	1198	2-MS9001EC	380	509.8	40.2	1136	1198
361	50	36.1	1738	789	1709	1803	2-MS9001FA	550	763.5	41.6	1709	1803

Notes:
1. Coal Fuel - Hydrogen Loss = 3.6%
2. Heat Rejection to Cooling Water From Condenser
3. Ambient Air Conditions: Temperature - 59 F (15 C)
   Pressure - 14.7 PSIA (1.013 bar)
4. Steam Turbine Exhaust Pressure - 1.5 in. HgA (38.1 MM HgA)
5. Unfired HRSG
6. Net Output Based on Once Through Cooling System
7. Estimated, Actual Performance Will Depend on Site Specific Repowered Equipment and Coal

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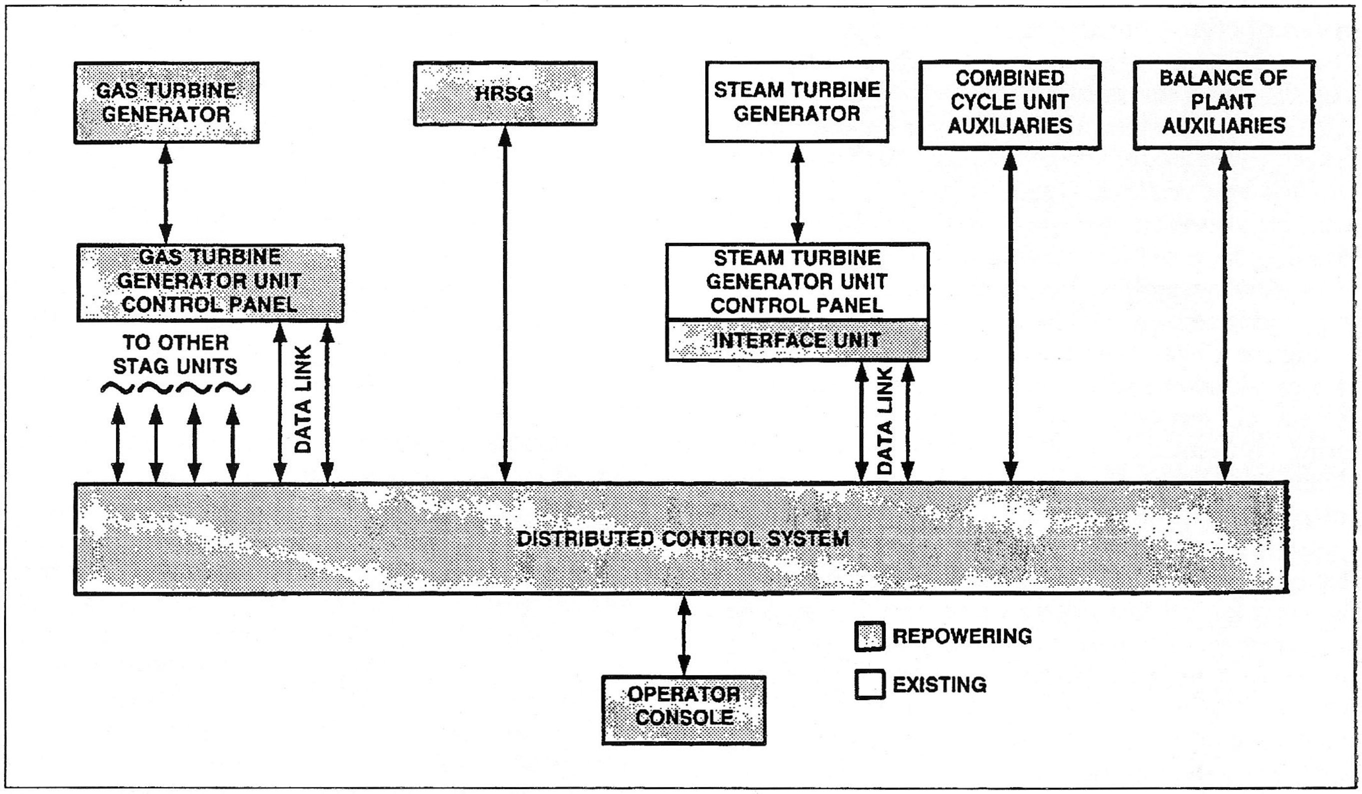

Figure 10. Distributed control system for plant with multi-shaft STAG combined cycle

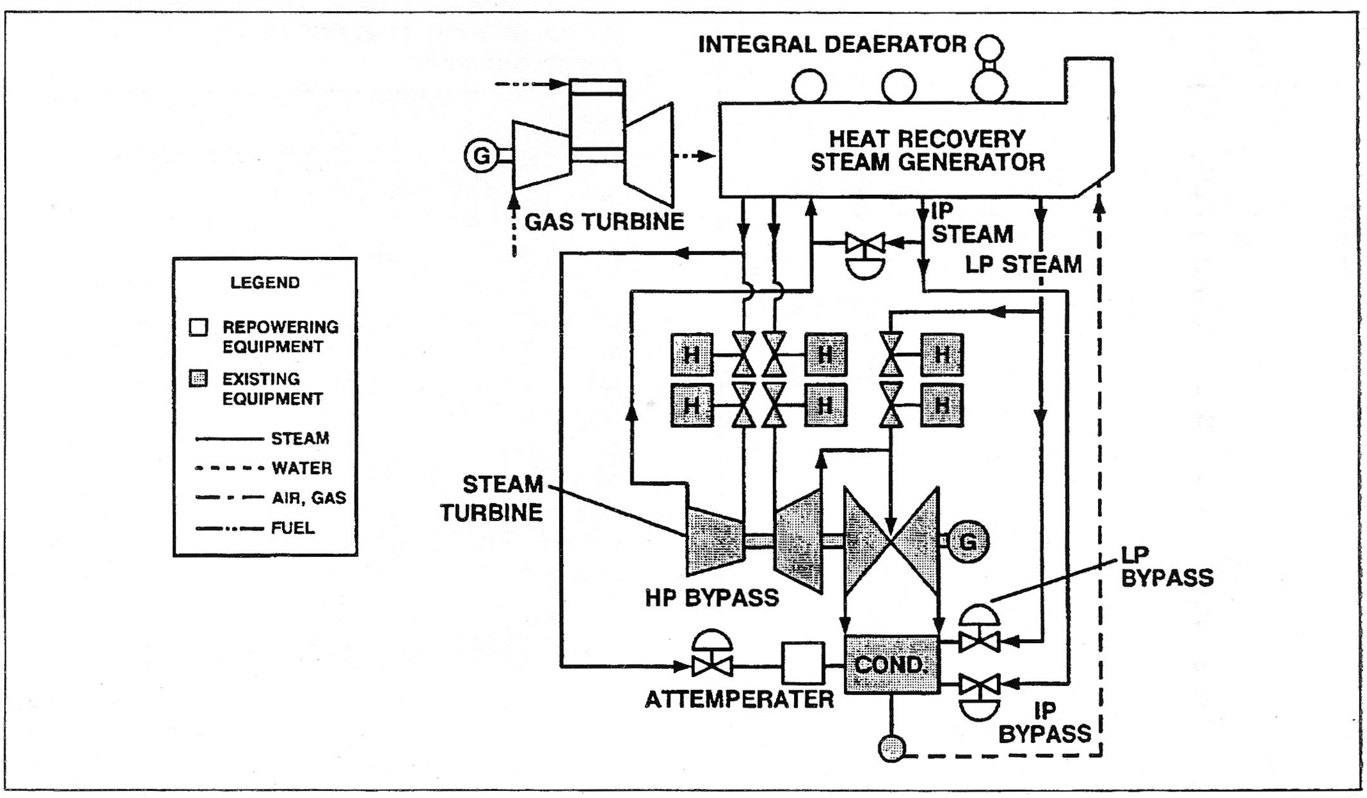

Figure 11. Repowered system control diagram

room operator. Starting and stopping is easy, but the starting program must be built around the capability of the existing steam turbine. Figure 12 shows the starting time for a typical combined-cycle system with two gas turbines and HRSGs and a single steam turbine. Depending on the transient temperature capability and loading rate of the existing steam turbine, the repowering combined cycle can have equal starting and loading flexibility.

Figure 13 presents the typical variation in output and heat rate with ambient air temperature for a heat recovery combined-cycle system. The repowering combined cycle can have comparable characteristics with proper matching of the repowering system and the existing steam turbine. Figure 14 presents typical part load performance for a similar heat recovery combined cycle, and Figure 15 shows a typical incremental heat rate curve. The heat recovery combined-cycle system formed by repowering an existing reheat or non-reheat steam turbine has flexible operating characteristics which enables it to follow load effectively, operate in a daily start-stop mode, or operate in continuous base load service.

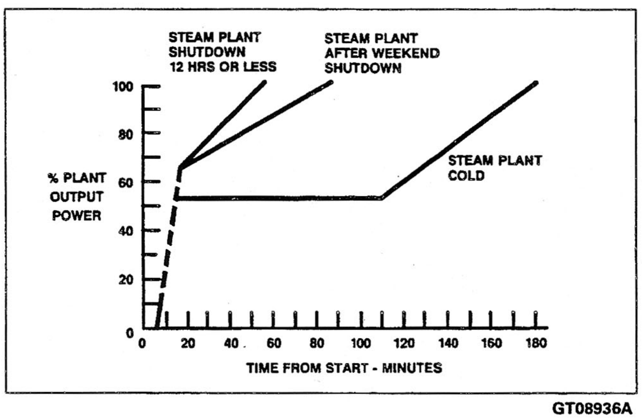

Figure 12. Multi-shaft STAG starting times

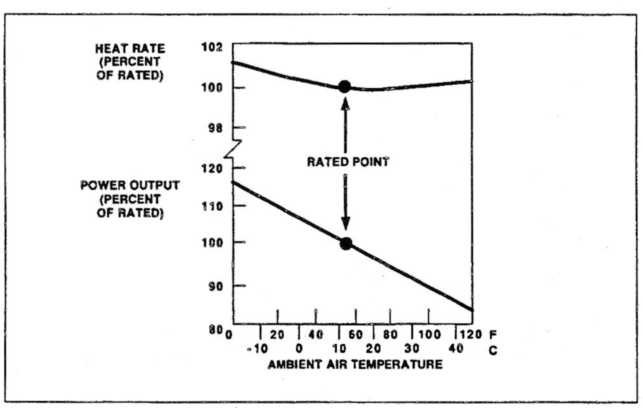

Figure 13. Power system performance variation with ambient air temperature

EVALUATING REPOWERING ECONOMICS

An evaluation of repowering requires the development of the cost-benefit relationships of this technology relative to other power generation options available to the utility. The evaluation considers the capital cost, operation and maintenance costs, and the operational philosophy of the repowered unit relative to the other generation options, as well as the operation of other existing generating equipment in the entire utility system.

A detailed repowering evaluation is frequently based on a power system generation planning study. The generation planning study is usually conducted using a generation planning decision simulation (computer) model of how the power system generating units operate in meeting the load demands over a period of time, typically 20 years. Capacity addition decisions are made to meet the required generation reserve margin (or generation system reliability target). If a repowering decision is implemented, the future generation addition schedule is impacted which may result in savings in future capacity needs. Capacity savings along with the resulting fuel and operation and maintenance (O&M) savings from more efficient operation comprise the repowering benefits or savings.

A schematic of the generation planning simulation process is given in Figure 16. Inputs required include:

- Characteristics of the existing units in the utility system
- Characteristics of the candidate generation options being considered for the next 20 years
- The hourly load profile and projected peak demands during the study period

Once the appropriate data is entered, the sequential annual simulation procedure is initiated. The power system reliability (or reserve margin) is calculated. If the power system requires capacity, the model proceeds to evaluate how much capacity of each future generation alternate candidate type is required to meet the generation reliability (or reserve margin) target. The model evaluates the investment charges of any added capacity and then performs a production simulation to evaluate the power system operating cost. The generation alternative with the least cost is added to the power system and the process is repeated for each succeeding year. (The simulation model can also be used to compute the environmental emissions from the total power system.)

While the generation system planning simula-

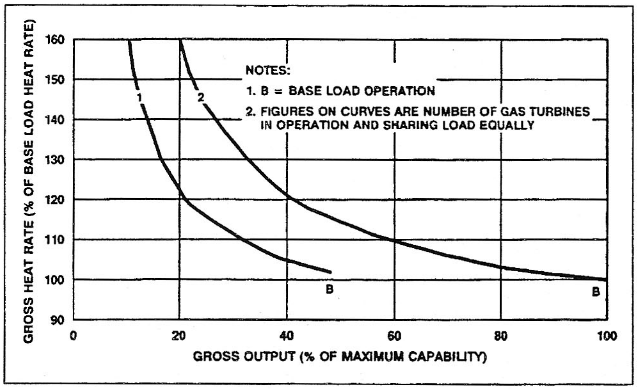

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Figure 14. Two STAG 209FA estimated heat rate variation with output

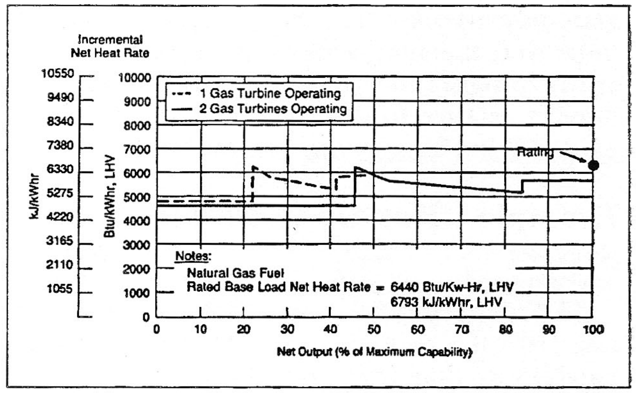

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Figure 15. Multi-shaft combined cycle with two gas turbines – incremental heat rate vs. output

tion model is the most rigorous (best) evaluation tool, it is often useful to approximate generation planning simulation results with an analytical economic evaluation method. The analytical economic evaluation is a simplified technique which requires considerably less time and effort than the detailed system simulation. The technique involves the use of several simplifying assumptions such as the expected operating mode (hours/yr) for each candidate system relative to the base capacity displaced. This technique can be effectively utilized by those familiar with utility system and equipment characteristics, and the impact of new generation sources on system operation and economics.

REPOWERING EXAMPLES

The following examples will illustrate the economic benefit of repowering for a utility requiring significant capacity, and having several candidate steam turbines whose ratings are somewhat in excess of 100 MW. The generation options are:

- HRSG Repowering – MS7001FA GTG – 107 MW STG
- BW Repowering – LM6000 GTG – 107MW STG
- FWH Repowering – LM6000 GTG – 107 MW STG
- IGCC HRSG Repowering – MS7001FA GTG – 133 MW STG
- New STAG 107FA

You will note that the listing includes a new STAG 107FA combined-cycle unit. Most utilities recognize that new combined-cycle units are typically the most economic type of capacity addition for applications in which the capacity factor is greater than 20% and suitable fuels are economically available. Thus, the new combined-cycle unit is the key economic competitor to repowering. A new combined-cycle unit would have a high efficiency steam turbine specifically optimized for the exhaust energy recovery system. Consequently, the unit power output and heat rate are slightly better than that of the repowered unit.

The projected performance, estimated investment costs and power system data for the repowering examples are given in Table 7. Performance data is presented on an absolute as well as an incremental basis. The incremental values are relative to the base steam system's net output, and a net heat rate of 10,000 Btu/kWh(10,550 kJ/kWh) HHV. The net base system output for the non-IGCC cases is 102 MW, and 133 MW for the IGCC options. Incremental performance and incremental plant cost are a better measure of the potential merits associated with repowering.

Repowering economics is dependent on the type of system being repowered, i.e. gas/oil fired versus a coal-fired steam plant. Generally speaking, the repowering options will look more economically attractive relative to a gas/oil fired existing system since the fuel costs in both are identical. For base systems fired on coal, a fuel

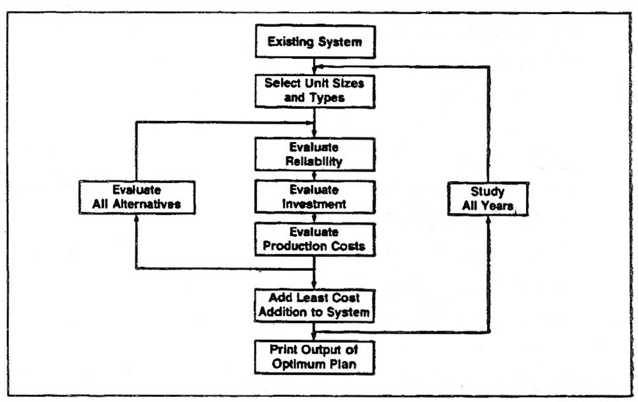

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Figure 16. Generation planning simulation

generally available at a lower cost than gas, the improved thermal performance of the repowered configuration yields a smaller energy cost benefit relative to the benefit that would have existed if the base system was gas/oil fired.

Example – Natural Gas-Fired Base System

The new repowered project has a better heat rate than the existing unit and thereby will dispatch more than the existing unit. In the case of HRSG repowering, the heat rate improves nearly to that of a new combined cycle and would be one of the most efficient plants on the power system. The HRSG repowered plant is projected to operate on the power system for 7000 hours/year. While the boiler windbox (BW) and feedwater heating (FWH) repowering options do not have as significant improvement in heat rate and dispatch priority, it is assumed for comparative purposes that they would also operate at 7000 hours/year. The existing 107 MW plant is assumed to be originally operating at 3000 hours per year.

The repowered plants produce more MW output capability and thereby reduce the need for additional new capacity. The credit for capacity is evaluated at 450 $/kW, which is the cost of installing simple-cycle gas turbines. The increased power output also permits the repowered plants to offset, or replace, generation from more expensive plants. The replaced generation is assumed to have have a heat rate of 10,000 Btu/kWh(10,550 kJ/kWh) HHV.

The economic comparison is made by first considering the operation of the power system without the repowered unit. The power system without the additional MW output of the repowered configuration must generate power from both the existing steam plant and other more expensive (replacement) generation. The existing steam plant is generally operated for less time than the repowered unit because it has a significantly poorer heat rate. In order to calculate the effects on the power system operating costs, the costs of the replacement generation for those periods of time are also included in addition to the costs of the existing steam plant.

Next, the power system with the additional MW due to repowering is evaluated. The net result is that the two comparisons are made on the basis of the same net electrical energy delivered from the power generation system. The net project gross income benefit is calculated based on the value of generated power less the expenses for fuel and O&M. The project gross income (income excluding plant investment fixed costs) is calculated for the power system with and without the repowering. The repowering investment divided by the difference in project gross income gives the investment payback, which is a measure of the economic benefit of the repowering alternative. Utility projects with paybacks under four years are generally considered attractive.

For the conditions given in Table 7 for existing steam plants fired using natural gas, the payback periods are as noted in Table 8. The results show that the HRSG repowering option is the most attractive yielding a 3.3 year payback. That is about 15% better than that of a new combined-cycle system, and significantly better than the FWH and BW repowering configurations.

Example – Coal-Fired Base Systems

Coal-fired steam plants are also candidates for repowering. If BW or FWH repowering are considered, the plant would use a mix of fuels; natural gas for the gas turbine generator, and coal for the existing boiler. With HRSG repowering, the repowering option would be fired on natural gas alone. Since the cost of coal is generally at least 30% less than natural gas, the energy cost of any of these options would be greater than the continued use of coal in the non- repowered configuration. Consequently, the repowered steam plant would be dispatched at lower annual operating hours than the base system. Thus, the economics of these repowered configurations will generally be poorer than the values developed for these options where the existing system is natural gas fired. In order to prove economic, these repowered systems would require a low natural gas fuel price relative to coal and a power system need for additional mid-range capacity.

If the first three repowering options in Table 7 were applied to a coal-fired base system, the estimated economics would be as displayed in Table 9. The deterioration of the economic performance relative to Table 8 is readily apparent.

An alternative to repowering using natural gas is the development of an IGCC repowering scheme using a synthetic gaseous fuel from coal as the gas turbine fuel. The performance and costs are as given in the last two columns of Table 7. The capital cost is significantly higher than the equivalent gas-fired cases due to the addition of the coal gasification system.

Table 7
BASIS FOR REPOWERING EXAMPLES
(All Costs in 1994 $)

		HRSG Repower MS7FA	BW Repower LM6000	FWH Repower LM6000	New STAG 107FA	IGCC Repower MS7FA	IGCC Reactivate Plant MS7FA
Existing Plant Fuel		Gas	Gas	Gas	Gas	Coal	Coal
Repowered Plant Output MW Net		244.0	141.4	140.8	252.3	257.8	257.8
Total Plant Cost $M		91.5	30.3	30.0	144.1	216.7	216.7
Average $/kW		375	214	213	571	841	841
Incremental $/kW		665	769	773	NA	1737	NA
Net Plant Heat Rate	- Btu/kWh - HHV	7153	9789	9254	6915	7991	7991
	- kJ/kWh - HHV	7545	10325	9761	7296	8429	8429
Incremental Heat Rate	- Btu/kWh - HHV	4877	8990	7036	NA	5745	NA
	- kJ/kWh - HHV	5144	9483	7422	NA	6060	NA
Operation - hr/yr							
Existing Plant		3000	3000	3000	3000	6000	6000
Repowered Plant		7000	7000	7000	7000	8000	8000

Power System Data			
Level Annual Fixed Charge Rate		16.5%	Fuel Cost $/MBtu ($/GJ) HHV
Present Worth Discount Rate		10%	• Natural Gas 2.50 (2.37)
Fuel & O&M Escalation Rate		5%/Yr	• Coal 1.70 (1.61)
Fuel Level Factor for 20 Years		1.41	O&M Fixed $/kW/yr
Value Capacity $/kW		450	• Natural Gas 6
Replacement Heat Rate	- Btu/kWh - HHV	10000	• Coal 15
	- kJ/kWh - HHV	10548	
Value of Generation $/MWh		60.0	O&M, Variable $1/kWh

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One of the IGCC repowering options is based on reactivating a facility which had been retired due to an inoperative boiler. The economic evaluation for a facility based on this premise will be more favorable than repowering an existing operating coal-fired facility due to the increased capacity credit available for the reactivated option.

The economic results for all the coal-fired options discussed are displayed in Figure 17. Results are displayed for natural gas at both $2.50/MBtu($2.37/GJ) HHV and $3.50/MBtu ($3.32/GJ) HHV. Furthermore, the analysis is based on the assumption that all power generation required from other portions of the utility system is based on gas-fired facilities at a 10,000 Btu/kWh (10,550 KJ/kWh) HHV heat rate.

The data displayed in Figure 17 indicate that the reactivated IGCC option is reasonably competitive with the HRSG, reactivated MS7FA case at a $2.50/MBtu($2.37/GJ) gas cost. Note how the economics of the IGCC cases improve significantly if the gas cost is $3.50/MBtu($3.32/GJ) rather than $2.50/MBtu($2.37/GJ), while coal is at the $1.70/MBtu($1.61/GJ) base value.

Environmental Emissions Considerations

The externality cost of plant emissions is becoming a key factor in the site permitting of

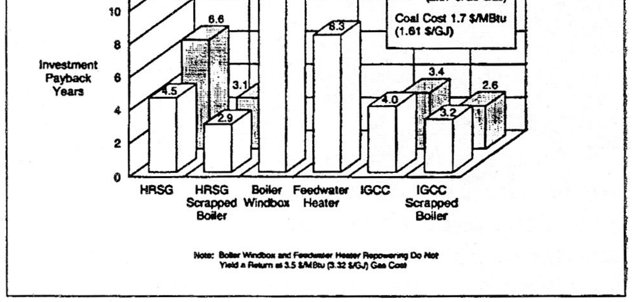

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Figure 17. Cool plant repowering economics

Table 8

ECONOMIC SUMMARY OF REPOWERING OPTIONS–NATURAL GAS-FIRED UTILITY SYSTEM

Option	HRSG MS7FA	BW LM6000	FWH LM6000	New STAG 107FA
Payback-Years	3.3	8.0	5.4	3.8

Basis: See Table 7, Basis for Repowering Examples (1993$ Costs)

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generation. Plants sited even two years ago if built today would face significantly increased emission requirements. In the United States, the Clean Air Act of 1970, amended in 1977, and again in 1990, requires more stringent emission control regulations. Where ambient pollution levels are not in attainment, then Lowest Achievable Emission Rate controls (LAER) are required along with offsets of existing plants. In areas where ambient pollutant levels are below the National Ambient Air Quality Standards (attainment areas), regulations require the Prevention of Significant Deterioration (PSD).

In attainment areas, new emission sources are required to use Best Available Control Technology (BACT). The EPA has established a policy, known as the "Top-Down" approach, for determining BACT in PSD permit reviews. In a BACT "Top-Down" analysis, the first step is to define the plant configuration with the LAER. From this "Top" position, alternative plant configurations with less control may be considered and justified on the basis of technical, environmental and/or economic infeasibility of the "Top" more stringent control strategy. One key factor is the economics of a more stringent LAER versus a lesser control technology plant configuration.

One means of evaluating the economics is to employ environmental externality costs for the pollutants, NO_x, SO_x, particulates, etc. Figure 18 illustrates typical values used in siting analyses for the key pollutants of SO_x, NO_x and particulates under 10 microns. "Pace Study" values are those obtained from a jointly funded DOE and New York state study, which has served as an industry benchmark for externalities values. Also labeled on the figures are values used by the Massachusetts Department of Public Utilities and California Energy Commission. The plant CO_2 production is another emission and is not considered an "ambient air pollutant" but is considered to be a "greenhouse gas" that may potentially contribute to long-term global warming.

The emission characteristics of power plants are illustrated in Figure 19. Gas turbine and combined-cycle plants burning natural gas have very low emission rates. Gas turbine NO_x is typically 9 parts per million (ppm) to 25 ppm, or 0.04 to 0.1 pounds per MBtu(0.17 to 0.43 kg/GJ). Natural gas in the USA has practically zero sulfur, and gas turbine particulate matter under 10 microns is very small, .005 #/MBtu(.002 kg/GJ). Natural gas-fired steam units have good emission characteristics but typically have higher NO_x values than gas turbines. Steam plants burning residual oil with 0.5% sulfur have higher SO_x emissions. Depending on the content and conversion to NO_x of fuel bound nitrogen, the NO_x emission can be slightly higher to 50% higher than natural gas-fired steam units. Coal units (2% sulfur con-

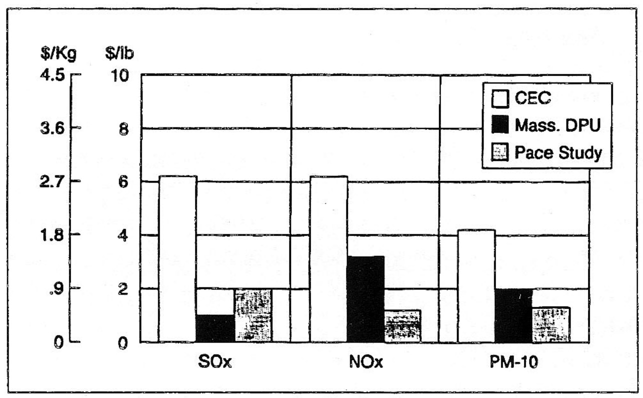

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Figure 18. Typical environmental externalities cost values

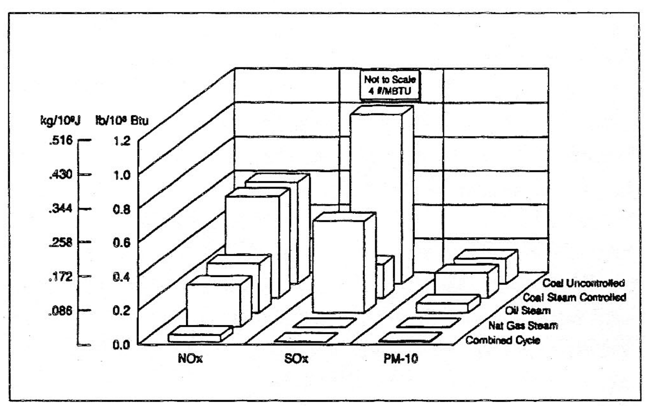

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Figure 19. Power plant emission characteristics

Table 9
ECONOMIC SUMMARY OF REPOWERING OPTIONS COAL-FIRED UTILITY SYSTEM

Option	HRSG MS7FA	BW LM6000	FWH LM6000
Payback-Years	4.5	10.9	8.3

Basis: 1. Coal Fired Plant Operation 6000 hr/yr
2. Repowered Options Operate 3000 hr/yr
3. Other Conditions of Table 7 Apply

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tent) with SO_X scrubbers tend to have high NO_X due to thermally produced NO_X along with conversion to NO_X of fuel bound nitrogen. Uncontrolled (no scrubber on 2% sulfur fuel) coal steam units produce significantly more SO_X.

The impact of including the Pace Study values of monetized externalities in the economics of the Table 8 example is shown graphically in Figure 20. The results without externality considerations are included for comparison. The results show that factoring externalities into the evaluation strengthens the case for all repowering options, and maintains the same ranking of competing systems as determined in the evaluations without externalities.

Additional Considerations

The repowering examples given in the previous sections were based on capital costs under ideal site conditions. The estimated costs suggested a unit cost ($/kW) which is lower than that of a new grass roots combined-cycle plant. In some cases, site considerations may result in a $/kW cost for the repowered configuration that is equal to, or greater than a new STAG plant. Under those conditions, the benefit or payback would be poorer than the new grass roots facility. However, that is true only if the grass roots option is available and can be implemented within the same time frame as the repowered option.

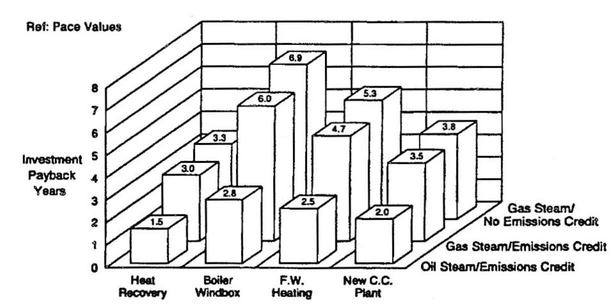

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Figure 20. Impact of emissions on economics of repowering (see Table 8 example)

In our present environment, siting new facilities is usually a major issue. And, the process of obtaining public acceptance and all site permitting activities can be a long, frustrating and expensive process. Thus, repowering an existing facility where many of the required permits exist, and where more effective use of an existing site may be appealing to the public, may be the most effective way of adding capacity, even if costs appear to be higher than those for new facilities.

CLOSURE

With the large number of older steam turbine generators in the utility industry, repowering provides an attractive option to increase capacity and improve the heat rate relative to siting new grass roots power generation facilities. This technology will also yield a reduction in environmental emissions, enhance the utilization of an existing site, and reduce the time required for project development since some of the permits for the existing facility may be applicable to the repowered configurations.

In order to establish economic viability, an application specific evaluation focused on the size and characteristics of the existing power plant equipment is required. That evaluation may show repowering to be an economically attractive option relative to a new combined-cycle plant for systems presently fired on natural gas or distillate fuel oils. Repowering may also be attractive for coal-fired facilities relative to the addition of equipment required for environmental compliance, or fuel switching strategies. In applications where the integration of a coal gasification plant is considered, the repowered facility would yield the most environmentally acceptable coal-based power generation technology available today to the utility industry.

LIST OF FIGURES

LIST OF TABLES

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

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