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GE Power Systems

GE IGCC Technology and Experience with Advanced Gas Turbines

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Introduction

Integrated gasification combined-cycle (IGCC) systems continue to penetrate the power generation market. General Electric has 17 projects in design, construction or operation totaling more than 3 GW of capacity. These projects range from 12 MW up to 550 MW in a variety of configurations incorporating eight different gasification technologies employing heavy oil, petroleum coke, coal, biomass and waste materials as feedstock. Half of these projects are now in operation and have accumulated over 250,000 fired hours of syngas experience while simultaneously demonstrating excellent environmental performance. Power generation availability has also been excellent, in excess of 90%, due to the ability of GE gas turbines to switch between fuels under load and co-fire multiple fuels.

In addition, IGCC capital cost continues to drop through advances in technology and the incorporation of lessons learned from operating facilities. The ability of IGCC systems to use low value feedstock and produce high value co-products along with power enhances the economic viability of new projects. The economics of IGCC systems now allow the technology to successfully compete in competitive power bidding situations where low cost indigenous gas is not available. The introduction of the next generation of gas turbine technology is expected to further reduce the capital cost of IGCC systems.

Gas Turbine Low Calorific Value (LCV) Fuel Capability and Experience

The ability to successfully burn LCV fuels over varying conditions requires significant combustion expertise. Since 1990, the can-annular combustion systems employed by GE have been modified to handle a wide variety of fuels and fuel mixtures. In addition, the can-annular approach to combustion systems provides significant advantages in LCV applications, particularly the ability to conduct combustion testing prior to equipment shipment.

This testing is conducted at a unique facility located in Schenectady, NY. (*See Figure 1.*) The Combustion Development Laboratory has a high-pressure test stand for each heavy-duty gas turbine model (6B, 6FA, 7EA, 7FA, 9E, 9EC, 9FA) as well as a component test rig. Using these test stands, a single combustion can is tested with a simulated syngas under full pressure and flow conditions. As opposed to partial flow and pressure conditions, full flow and pressure conditions enable the performance characteristics of an individual combustion can to be readily translated to full machine performance. This ability to test at full flow and pressure conditions has been one of the single largest contributors to the successful start-up and operation of GE gas turbines in LCV gas applications.

Due to the unique demands on the combustion system by LCV gases, full characterization of combustor performance is essential. This testing involves considerably more than a simple verification of combustion stability. It is important to address combustor operation and its affect on overall gas turbine operation. As a result, a wide variety of tests are conducted for

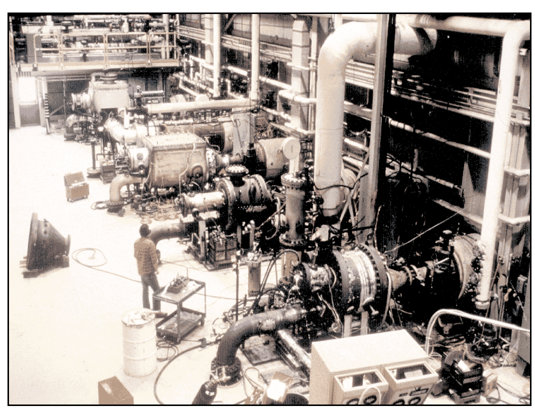

Figure 1. GE Combustion Development Laboratory

all unique LCV gases. *Figure 2* shows the list of typical combustion tests and variables. The purpose of these tests is to evaluate combustor and machine performance as load conditions, LCV gas composition, fuel mixtures, ambient conditions, diluent composition and conditions and other factors vary. As these conditions change, an assessment of combustion dynamics, metal temperatures, system pressure losses, emissions, and exit temperature profiles is conducted.

Combustion Test Parameters

Combustion Parameters

- Emissions
  - NO, NO_x, CO, UHC, O_2, CO_2
- Combustor Metal Temperatures
- Combustion Dynamic Pressures
- Combustor Exit Temperature Profiles
- Combustion System Pressure Drop
- Air Extraction Limits
- Power Augmentation Limits
- Combustion System Temperatures and Pressures
- Turn Down
  - Minimum Temperature Rise
  - Minimum Calorific Value

Test Parameters

- Air Flow and Temperature
- Air Extraction Flow
- Diluent (Inert) Injection Flow
- Syngas Composition
- Syngas Temperature
- Conventional Fuel Flow
- Syngas/Conventional Fuel Split
- Power Augmentation Flow
- Combustor Exit Temperature

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Figure 2. Combustion test parameters

LCV gases can vary widely from one application to another and are highly dependent on the particular process producing the gas, the oxidant used in the process and the process feedstock. For example, the LCV gas produced by an air-blown, coal-fueled, fluid bed gasifier will differ significantly in composition from an oxygen-blown, vacuum residue-fueled, entrained-flow gasifier. The resulting gas composition, flammability and calorific value work in concert to form the basis for the combustion system design and response.

Most LCV gases have a wide range of flammability when compared to more conventional fuels such as natural gas. In *Figure 3* it can be shown that there is considerable difference between the rich and lean fuel firing limits for most LCV fuels. As gas calorific value becomes lower (moving to the left on the flammability curve), flammability limits narrow and the combustion process itself becomes more sensitive to changes in calorific value. Changes in the gas composition of very low calorific value gases such as blast furnace gas (BFG) can quickly move a gas from flammable to the non-flammable region of the chart. As a result, GE has developed special designs to accommodate very low heating value fuels such as BFG. The unique capabilities of the Combustion Development Lab allow GE to fully explore these issues and design LCV combustion systems for a specific application. Combustion issues can be explored in the lab and solutions implemented in the combustion system design and production hardware prior to actual field operation.

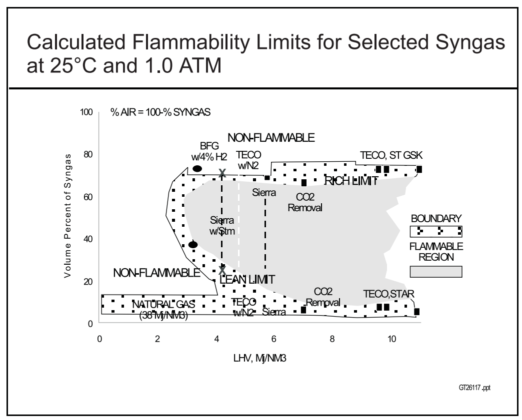

Figure 3. Syngas flammability limits

As shown in *Table 2*, as of March 2000, GE gas turbines applied to LCV applications have accumulated approximately 260,000 syngas-fired hours with the three 109E combined cycles at ILVA representing the fleet leader with more than 78,000 hours of operation. GE gas turbines burning LCV gas encompass a wide variety of operational demands, varying gas compositions, and gas turbine frame sizes and include "E" and "F" level gas turbine technology. Some units such as the 6FAs at Exxon Singapore are expected to operate at 40 discrete points while others such as the 7FA at Tampa Electric are designed to operate at baseload conditions on syngas once the unit has achieved startup. The composition of the syngas consumed in these operating units also varies considerably from project to project. A measure of this project-to-project variability is the hydrogen content of the fuel. As shown in *Table 3*, the hydrogen content of these operating units varies widely from a low of 8.6% at ILVA to a high of 61.9% at Schwarze Pumpe with heating values of 193 and 318 Btu/SCF respectively. These diverse conditions and operating demands emphasize the importance of sound combustion system design.

Based on the operating history of these units, it is clear that GE gas turbines and combined cycles applied to LCV applications can achieve reliability, availability and maintainability (RAM) performance levels comparable to natural gas-fueled units. The use of a properly designed dual-fuel combustion system and its controls are key to achieving these RAM levels.

GT Fuel Flexibility with Variable IGCC Process Operations

For IGCC high-hydrogen content syngas fuels, GE gas turbine units include dual fuel capability (syngas/natural gas or syngas/liquid). A conventional fuel is required for startup and shutdown, although the combustion and control systems are designed to operate over the entire load range on either fuel. Depending upon the quantity of syngas available, the unit may be operated in a variety of fuel conditions ranging from co-firing (i.e. startup fuel and syngas), to full syngas firing at rated load conditions. During normal process operations, where the syngas production matches the turbine fuel requirements, the unit is transferred fully onto syngas, and may utilize supplemental diluent injection (e.g. nitrogen, carbon dioxide, or steam), to effect NO_x emission control and/or augment power production.

When process operations change whereby syngas fuel becomes limited or otherwise unable to meet the total turbine fuel requirements, a transfer back to co-fired operations using start-up fuel is selected or can be automated to hold power to operating limits. While operating in co-fired or mixed-fuel mode, fuel input limits (expressed as a percentage of total heat input to the gas turbine), on each fuel are imposed in order to maintain minimum allowable pressure drop conditions. The limits for co-firing syngas/liquid are typically 90% / 10% syngas/liquid to 30% / 70% syngas/liquid. Since each gas passage in the fuel nozzle is essentially a fixed orifice, the minimum syngas flow corresponds to a minimum allowable pressure drop across the particular gas nozzle, which in turn has been determined for each system primarily to avoid unacceptable pressure fluctuations (combustion dynamics). A minimum pressure ratio is also required to maintain adequate can-to-can fuel distribution as well as avoiding cross flow from can-to-can. The minimum liquid flow being that required to avoid overheating of fuel pumps and again to establish good fuel distribution.

For dual gas fuel (syngas/natural gas) systems, the minimum gas flow requirement can be substantially reduced below 30% heat input by using a variety of control schemes that may include a combination of co-firing and fuel blending. The Shell Pernis fuel system, for example, operates on a variety of syngas, natural gas, LPG mixtures, as well as 100% natural gas as illustrated in *Figure 4*. A similar system has been applied to the Exxon Singpore gasification project to meet operational requirements

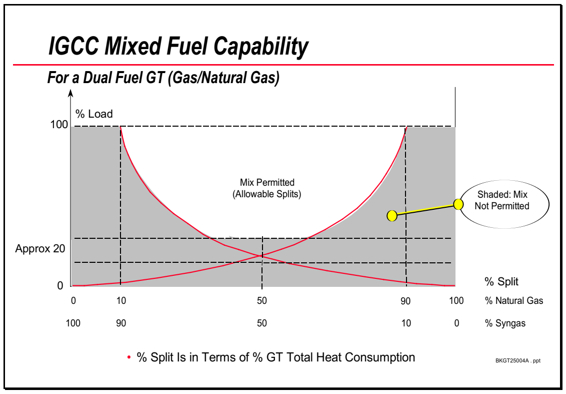

Figure 4. Mixed fuel firing

which allow for a 90% / 10% split on syngas and natural gas as illustrated in *Figure 4*. Nominally, for a dual gas – dual manifold system without blending, the minimum fuel split for any one gas is 30% by heat input at rated load.

Variation in syngas production can be compensated by co-fired operations when constant output is necessary. For example, in cases where the quantity of available syngas is changing due to chemical co-production priorities, a modulating fuel split arrangement can be utilized where the percent syngas firing is continuously adjusted to match the process operations. The co-fired fuel is then raised or lowered to maintain turbine output on load control. While co-firing operations may increase operating costs, the revenue gained from incremental kilowatt hour generation may more than compensate with improved generation capacity factors accumulated over annual operating periods.

The gas turbine when fully fired on typical syngas compositions has the potential to develop enhanced power output capacity due in large part to the significant flow rate increase (~14% incr. over natural gas), resulting from the low heating value fuel combustion products passing through the turbine. *Figure 5* shows the 20-25% higher ratings that are normally achieved when operating on syngas, and illustrates the potential for flat ratings across the ambient temperature range. These increased ratings take into account the GE criteria for parts lives which requires a reduction in syngas firing temperatures to maintain hot gas path parts at temperatures similar to natural gas units. The higher turbine flow and moisture content of the combustion products can contribute to overheating of turbine components. The insert in *Figure 6*, shows that these effects, uncontrolled, could lead to life cycle reductions on the "stage 1 bucket" of more than half. GE IGCC control systems include provisions to compensate for these effects.

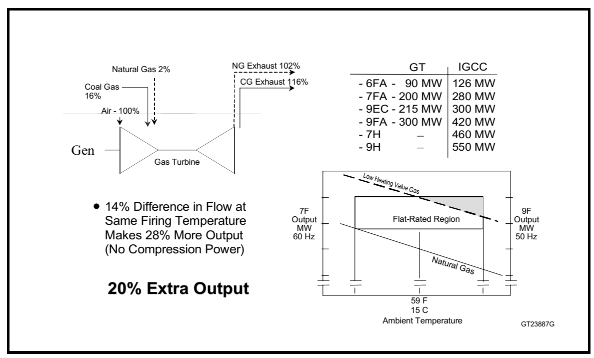

Figure 5. IGCC output enhancement

Since fuel process operations do not vary significantly with ambient operating conditions, the gas turbine power train provides nearly constant output generation when linked to syngas fuel production. At low ambients the gas turbine airflow is regulated by variable inlet guide vane (IGV) position to maintain constant fuel/air ratios. As ambient temperatures increase, IGVs open to maintain airflow until full open position is reached. The flat output rating may be further extended to higher ambients by utilizing surplus process steam and/or nitrogen injection for power augmentation. Such an arrangement is employed at the Tampa

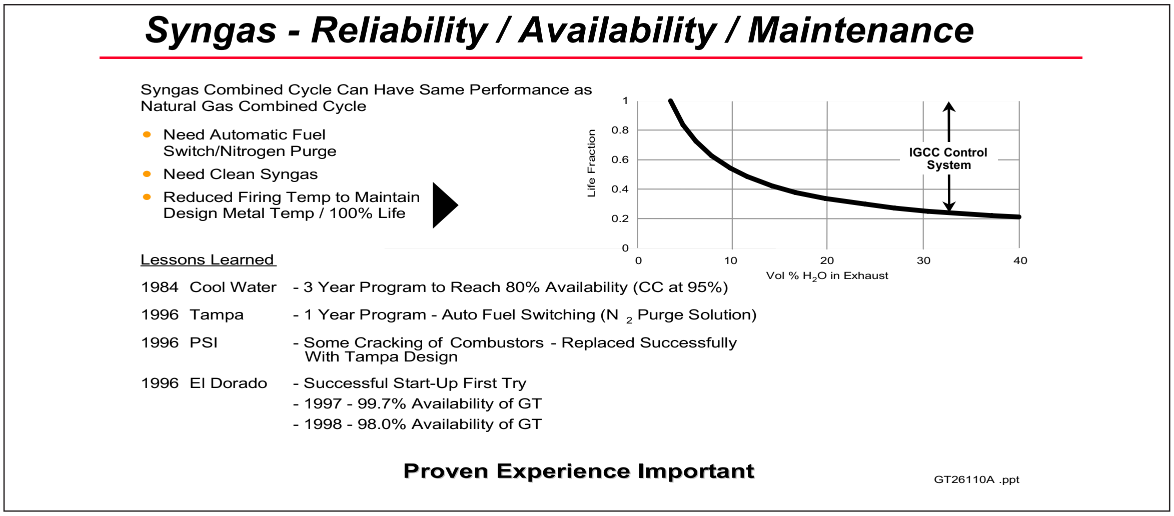

Figure 6. Effect on firing temperature

Electric Polk IGCC project where gas turbine output is maintained nearly constant for ambient temperature conditons up to 32°C/90°F with process nitrogen injection.

Environmental Costs

IGCC plants sited to date offer designs that exhibit superior environmental performance compared with generation alternatives using similar feedstocks. Emission pollutants can include low levels of oxides of nitrogen (NO and NO_2), carbon monoxide, unburned hydrocarbons, oxides of sulfur, and particulate matter. In particular, the emission of acid rain pollutants (including NO_2 and SO_2), from gas turbines fueled by syngas are to a large degree characterized and controlled by process design and integration with the turbine combustion system. *Figure 7* lists NO_x emission levels achieved to date with GE gas turbine units operating at several plant facilities over the past fifteen years, in addition to predicted levels for other IGCC sites currently under construction.

Typically, with oxygen-enriched gasification processes, nitrogen is readily available for direct injection into the gas turbine combustion system as a primary diluent for NO_x control. Similarly, for syngas processes where nitrogen is not available, fuel moisturization using a process saturator is extremely effective in reducing combustion flame temperatures to control NO_x emissions. GE has performed extensive laboratory testing using lower calorific value syngas to evaluate combustion system performance including flame stability and efficiency, as well as emission characterization. Full pressure and temperature test programs using various process diluents including: N_2, H_2O, and CO_2, as shown in *Figure 8*, illustrate that dramatic NO_x reduction is achievable, even at 1400°C

IGCC Environmental Performance

Operating	NOx (ppmdv@15% O2)
Cool Water	25
PSI - Wabash	<20
Tampa - Polk	<20
Texaco - El Dorado	<25
Predicted	
Sierra Pacific	<42 (<9 Thermal)
Motiva Delaware	9-15
Sarlux	<30
Fife	<42

Figure 7. IGCC NO_x emissions

combustor exit temperatures, by effective reduction in equivalent fuel heating value and primary flame zone temperatures. Although many process applications utilize premixing of these diluents with the syngas prior to delivery to the gas turbine, laboratory testing has determined there is little difference on the net effect of emissions reduction between premixing and direct injection into the combustor reaction zone. GE prefers direct diluent injection into the individual combustors for reasons associated with controllability, efficiency, and system cost. For extremely low NO_x emission sites (i.e. < 9 ppmvd @ 15% O_2), back end treatment using selective catalytic reduction methods in the exhaust heat recovery equipment area may become necessary.

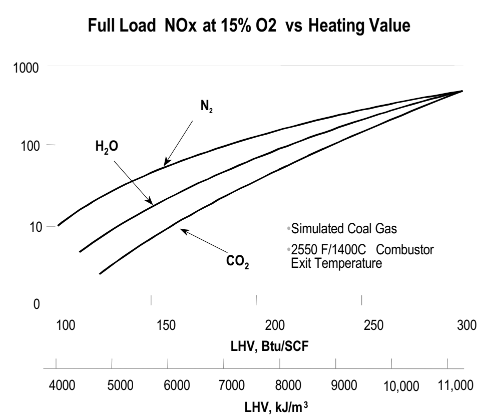

Figure 8. Effect of diluents for NO_x

The residual sulfur compounds remaining in the syngas following process treatment and cleanup directly determine sulfur oxide emissions. A variety of process designs are used which establish the level of sulfur recovery from the raw syngas. Cost constraints are the primary consideration, however, sulfur recovery efficiencies in the range of 98–99.5% incorporating COS hydrolysis are readily achievable to meet site permitting requirements.

The thermal performance of IGCC plants burning heavy fuels are proving to be superior to other generation alternatives particularly when using today's advanced gas turbine technologies. Continued improvements in IGCC cycle integration coupled together with further technological advances in turbine designs (e.g. GE model H), are paving the way for higher cycle efficiency levels that will not be achievable with competing generation technologies. As a result, carbon dioxide production per kilowatt of power generation with IGCC plants burning these fuels will be the lowest in the industry. Combustion testing completed earlier this year at GE's Combustion Development Laboratory in Schenectady, NY have confirmed stable combustor operations and excellent emission performance characteristics while burning syngas composed of 50% hydrogen and 50% nitrogen, allowing for the elimination of nearly all CO_2 emissions. IGCC plants, where necessary, can be readily designed to extract and sequester CO_2 from pre-combustion syngas, allowing for virtually carbon-free emissions.

Economic Considerations

Dramatic improvements have been made in IGCC system capital cost. Solid fuel plants have been recently bid for less than $1,000/kW on a turnkey basis. This is 30–40% of the cost of the first few IGCC plants. These capital cost reductions are due to a variety of factors, the most influential being: 1) gas turbine performance enhancements; 2) gasification system enhancements; and 3) EPC learning curve effects.

Economics have largely shaped the configurations, applications, and end users of IGCC systems in recent plant decisions. Although early technology studies focused on coal-based utility power production, economics now favor a different approach. Most of the later IGCC plants are constructed by IPPs, predominately in refinery applications using refinery bottoms as gasification feedstock and produce electricity and high value co-products such as hydrogen and steam for refinery purposes. In these configurations the technology has become very competitive and will continue to drive down costs and spur innovation.

Based on today's gas turbine technology, applications using solid and liquid opportunity fuels with cogeneration and/or co-production schemes are competitive in the marketplace. Continued technology improvements and optimized cycle and co-production configurations continue to drive down the capital cost of IGCC and its resulting cost of electricity. In addition, coal-based IGCC plants are now a competitive alternative in countries with severe environmental restrictions or areas that depend on the use of high-priced power generation fuels such as LNG.

An example of the continued improvement in coal-based IGCC performance and economics is shown in *Figure 9*. A recent study by GE, Texaco, Inc. and Praxair, Inc. evaluated a variety of coal-fueled IGCC configurations based on a GE 9FA based combined cycle. Through cycle optimization studies and by incorporating the lessons learned from operating facilities, cycles such as the high efficiency quench (HEQ) can be utilized. The HEQ cycle uses high pressure quench gasification coupled with a syngas expander. The HEQ cycle maintains high IGCC system output while reducing the total capital cost by eliminating a significant portion of the high temperature heat exchangers in the gasification plant. The results of the study indicate that the 9FA HEQ configuration costs 10% less on a cost of electricity basis than it did just two years ago. The full results of this study are published in other papers. Continued improvements in gas turbine and gasification system performance along with increased operating experience will continue to reduce the investment required on future IGCC plants.

The next generation of gas turbines is expected to enhance the economic competitiveness of today's cogeneration/co-production IGCC configurations as well as allow coal-based power-only IGCC plants to successfully compete in the market. Technology improvements embodied in the GE "H" machine are projected to yield substantial improvements in performance and significant reductions in the capital cost of all IGCC systems. Early studies predict a significant total capital cost reduction in mature "H"-based IGCC systems cost with efficiency reaching 50% (LHV basis) on coal-based power production. *Figure 10* shows the relative cost of electricity for various technology and fuel options.

9FA Based HEQ IGCC

Feedstock	1997 Coal	1999 Coal	2000 Oil
Output (MW)	408	449	436
Efficiency (%)			
- LHV	42.5	43.3	45.1
- HHV	40.9	41.8	42.8
Cost of Electricity*	5.26	4.69	4.39

Another 10% COE Reduction

*(20 yr. levelized)

Figure 9. Continued COE reductions

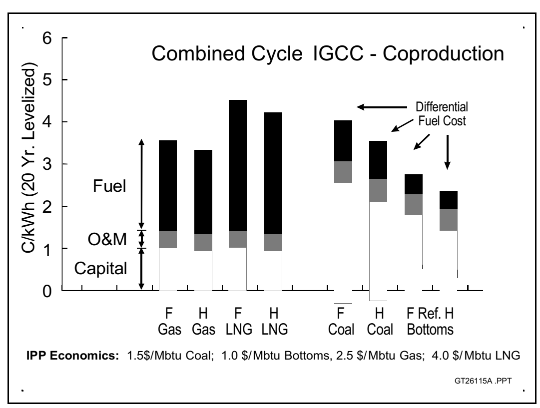

Figure 10. Cost of electricity comparison

In places that do not have cheap indigenous gas, IGCC is already a competitive technology. Since IGCC can use dirty, low cost opportunity fuels, the "fuel cost differential" further reduces the cost of electricity. The introduction of "H" level gas turbine technology is expected to fundamentally shift the economics of IGCC systems. Studies are currently in progress to more fully evaluate this potential.

Project Experience

GE leads the world in the application of its heavy duty gas turbines to gasification combined-cycle gas projects. As of December 1999, twelve GE heavy-frame gas turbines were operational using synthesis gas from the gasification of coal, petroleum coke and other low grade fuels. Seven additional gas turbines at three different plants will become operational in 2000. These plants are Motiva-Delaware (two 6FAs), Sarlux (three 109Es), and Exxon Singapore (two 6FAs). Additional units for gasification applications are on order with startup dates ranging from 1999 through 2003. Once these projects are in operation, a total of 26 GE gas turbines will be operational with syngas covering the entire product family from PGT10B up through and including 9FA gas turbines.

The IGCC projects include various levels of integration with the gasification plant, ranging from steam-side integration only on many projects, to nitrogen return (Tampa & Motiva), and full steam and air integration including both air extraction and nitrogen return (El Dorado, Pinon Pine). GE turbines are in operation on syngas-from-gasifier technologies by Texaco (solid fuels and oil), Destec (coal), GSP (coal and waste), Shell (oil), and operation with the Lurgi gasifier (biomass), is scheduled for 2001.

In addition to the synthesis gas applications and operating experience summarized in *Tables 1 and 2* below, GE also has numerous turbines in operation on other special fuel gases, including refinery gases containing hydrogen, butane, propane, ethane, and blends of various process gases. These units include six Frame 3s, seventeen Frame 5s, 19 Frame 6s, and 15 Frame 7EAs.

GE's success with low and medium Btu fuel gases is a consequence of extensive full-scale laboratory testing on various fuels for over 15 years at GE's Combustion Development Laboratory in Schenectady, NY. As mentioned earlier, this facility provides the unique opportunity to simulate customer specific fuel gas, and then test a single combustor at full-flow, full-pressure operations to investigate combustion conditions, and confirm liner cooling and fuel nozzle designs before fabrication of the production hardware. *Table 3* shows the wide range of syngas compositions which are being used on various GE low-Btu projects. Data from these tests form the basis for emission guarantees, turndown performance, and parts lives estimates. Most recently GE has made laboratory improvements to incorporate fuel blending systems. The primary combustibles, namely CO and H_2, are supplied in tube trailers. N_2, CO_2, steam, natural gas and ammonia may be blended on-line to achieve the desired fuel composition. With this arrangement, it is now possible to vary the H_2 content as well as the H_2/CO ratio during a test to evaluate hardware capabilities and simulate field operations where syngas compositions may vary daily to meet changing chemical co-production requirements.

Conclusions

The successful integration of heavy-duty gas turbine technology with synthetic fuel gas processes using low-value feedstocks is proving to be commercially viable in the global power generation marketplace. Continuous cost improvements in both gas turbine and process plant design is allowing for significant market penetration into refinery based IGCC applications as witnessed by several projects currently in operation with additional plants coming on-line by year's end. The introduction of the GE "H" gas turbine technology raises the prospect for significantly greater cost reductions as power densities and cycle efficiencies set new operational benchmarks for the foreseeable future.

Gas turbine fuel flexibility and co-firing capability provide additional IGCC economic benefits allowing for the co-production of other high value by-products while maintaining high power generation availability. The capability to pre-test combustion hardware using simulated fuel gases at full operating conditions has further demonstrated superior environmental performance with coal and other low grade feedstock and provides for optimized integrated plant designs. In addition to very low emission levels of particulate, sulfur dioxide and nitrogen oxides, the potential to remove carbon dioxide and burn a hydrogen-rich syngas in the gas turbine may become a significant advantage for IGCC systems as countries take steps to reduce their overall carbon dioxide emissions.

Finally, experience gained from several syngas projects are providing invaluable lessons learned that continue to foster cost reductions and improve operational reliability. As additional IGCC plants go operational, further improvements in system performance and plant design are to be expected drawing from an extensive successful experience base.

Customer	Location	COD	MW	Pwr Block	Application	Integration	Gasifier	Fuel
Cool Water IGCC	Barstow, California	1984	120	107E	Power	Steam	Texaco	Coal
PSI Wabash River	Terre Haute, Indiana	1996	262	7FA	Power	Steam	Destec	Coal
Tampa Electric	Polk, Florida	1996	250	107FA	Power	Steam/N_2	Texaco	Coal
Pinon Pine Sierra Pacific	Sparks, Nevada	1996	100	106FA	Power	Steam/Air	KRW	Coal
Texaco El Dorado	El Dorado, Kansas	1996	40	6B	Cogen	Steam/Air/ N_2	Texaco	Pet Pet Coke
ILVA ISE	Taranto, Italy	1996	520	3x109E	Cogen	None	Steel Mill	COG
SUV Vresova	Vresova, Czech Rep.	1996	350	209E	Cogen	Steam	ZVU	Coal
SVZ	Schwarze Pumpe, Germany	1996	40	6B	Cogen/ MeOH	Steam	GSP	Coal/ Waste
Shell Pernis	Pernis, Netherlands	1997	120	206B	Cogen/H_2	Steam	Shell/ Lurgi	Oil
Fife Energy	Fife, Scotland	1999	109	106FA	Power	None	Lurgi	Coal/ Waste
Motiva	Delaware City, Delaware	1999	180	2-6FA	Cogen	Steam/N_2	Texaco	Pet Coke
Sarlux	Sarroch, Italy	2000	550	3x109E	Cogen	Steam	Texaco	Oil
Fife Electric	Fife, Scotland	2000	350	109FA	Power	None	Lurgi	Coal/ Waste
Exxon Singapore	Jurong Island, Singapore	2000	173	2-6FA	Cogen	None	Texaco	Oil
IBIL Sanghi	Gujarat, India	2001	53	106B	Cogen	Steam/Air	Carbona	Coal
Bioelettrica TEF	Cascina, Italy	2001	12	1-PGT10B/1	Power	Steam	Lurgi	Wood/ Waste
EDF-Total	Gardanne, France	2003	400	2x9E	Cogen/H_2	Steam	Teaxco	Oil

Table 1. GE IGCC projects

Customer	Type	MW	Syngas Start Date	Hours of Operation		
				Syngas	N.G.	Dist.
Cool Water	107E	120	5/84	27,000	-	1,000
PSI	7FA	262	11/95	17,230	-	3,500
Tampa	107FA	250	9/96	18,060	-	4,300
Texaco El Dorado	6B	40	9/96	17,180	24,100	-
Sierra Pacific	106FA	100		0	26,500	-
SUV Vresova	209E	350	12/96	53,170	2,200	-
Schwarze Pumpe	6B	40	9/96	21,080	-	3,400
Shell Pernis	2x6B	120	11/97	29,770	18,900	-
ISE/ILVA	3x109E	540	11/96	78,950	3,700	-
Fife Energy	6FA	80		0	11,600	-
			GE Totals	262,440	-	-

Table 2. GE Syngas experience (March 2000)

Syngas	PSI	Tampa	El Dorado	Pernis	Sierra Pacific	ILVA	IBIL	Schwarze Pumpe	Sarlux	Fife	Exxon Singapore
H_2	24.8	27.0	35.4	34.4	14.5	8.6	12.7	61.9	22.7	34.4	44.5
CO	39.5	35.6	45.0	35.1	23.6	26.2	15.3	26.2	30.6	55.4	35.4
CH_4	1.5	0.1	0.0	0.3	1.3	8.2	3.4	6.9	0.2	5.1	.5
CO_2	9.3	12.6	17.1	30.0	5.6	14.0	11.1	2.8	5.6	1.6	17.9
N_2 + AR	2.3	6.8	2.1	0.2	49.3	42.5	46.0	1.8	1.1	3.1	1.4
H_2O	22.7	18.7	0.4	--	5.7	--	11.5	--	39.8	--	.1
LHV, - Btu/ft^3	212	202	242	209	127	193	115	318	163	322	242
- kJ/m^3	8350	7960	9535	8235	5000	7600	4530	12,520	6420	12,690	9,530
T_{fuel}, F/ C	570/300	700/371	250/121	200/98	1000/538	400/204	1020/549	100/38	392/200	100/38	350/177
H_2/CO Ratio	.63	.75	.79	.98	.62	.33	.83	2.36	.74	.62	1.25
Diluent	Steam	N_2/H_2O	N_2/Steam	Steam	Steam	--	--	Steam	Moisture	Water	N_2/Steam
Equivalent LHV											
- Btu/ft^3	150	118	113*	198	110**	--	115	200	--	*	116
- kJ/m^3	5910	4650	4450	7800	4334	--	4500	7880	--	--	4600

* Always co-fired with 50% natural gas
** Minimum range

GT25217B

Table 3. Syngas comparison

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