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**UTILIZATION OF REFINERY RESIDUES
WITH COGENERATION**

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1. **INTRODUCTION**

The Refinery Industry is confronted with a difficult challenge: crude oils are getting heavier and more contaminated while the demand and the quality of light products, i.e. transportation fuels, are increasing. These two facts are in conflict and force the industry to invest heavily to convert heavy products to light products and improve their quality, to satisfy the requirements of progressively severe environmental regulations.

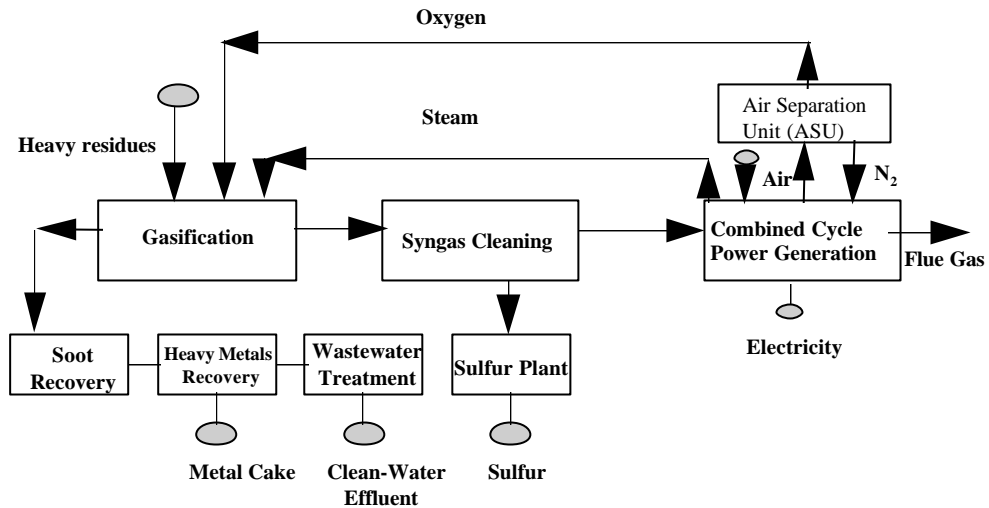
Conversion Technologies have been developed and improved over the years under the pressure of this challenge. However the zero residue production still remains an impossible target. Conversion, even in its most advanced and costly form, leaves the refiner with a residual bottom product reduced in volume but more contaminated with sulphur and metals, thus more difficult to dispose.

Yet the refiner must continue to produce high quality transportation fuels and find a solution for the heavy residue, such as tar, coke, cracking bottoms, asphalt. These residues be accumulated or stored for ever.

Using these heavy residues for production of electrical energy, steam, hydrogen and other syngas based chemicals, is a solution to the problem, provided this conversion can be done in an environmentally friendly manner. This paper provides the Refinery Industry with the general features, cost and performance data of two key technologies for converting residues to marketable products in full respect of the environment. These technologies are: Integrated Gasification Combined Cycle (IGCC) and Circulating Fluid Bed (CFB Combustion).

2. **INTEGRATED GASIFICATION COMBINED CYCLE (IGCC)**

IGCC involves the gasification of the heavy residues. Fig. 1 is a simplified diagram of the process.



Gasification with oxygen, by means of partial oxydation, converts the hydrocarbon structure into a mixture of hydrogen and carbon monoxide, called syngas. Partial oxydation is a flexible process, that can handle any kind of refinery residue; liquid, solid and even refinery sludges and tank bottoms.

Syngas is subsequently cleaned in steps, which include COS hydrolysis, H₂S removal and Claus conversion to elemental sulphur, heat recovery, expansion and, if required, saturation.

Typically the composition of the clean syngas produced from a heavy residue is:

CO	45.5	% vol.
H ₂	43.0	"
CO ₂	8.2	"
CH ₄	0.3	"
Ar	1.0	"
N ₂	0.5	"
H ₂ O	1.5	"

By products of the process are sulphur, water effluent, sufficiently clean for disposal in rivers or sea, and a metal concentrate that can be reused for vanadium recovery in the metallurgical industry.

Clean syngas can be generated at any pressure between 20 and 70 bar, depending on the final use of syngas. Syngas can be employed to produce pure H₂, by selective membrane separation or shift reaction followed by pressure swing adsorption (PSA) purification.

Syngas can also be used to synthesize various chemicals such as methanol, ammonia, formaldehyde, MTBE, oxoalcohols, etc.

Syngas is also an excellent fuel for gas turbines, thus providing a link between inexpensive residual fuels and combined cycle, a technology with thermal efficiency well above 50 percent.

In recent years, there has been considerable progress in enhancing the efficiency and lowering the cost of IGCC technology.

This has been achieved through improved gasification processes, advanced F generation gas-turbine technology and optimised integration of major IGCC components.

State-of-the-art IGCC technology is economically competitive with other advanced energy production technologies and offers excellent environmental performance. This is shown by the data in Table 1 and Table 2, which profile two hypothetical IGCC modules designed for integration into the operations of oil refineries. Each of the module designs is based on the more efficient heat-exchange approach to cool the syngas produced, rather than quenching.

Table 1: Comparison of IGCC-Module designs

		MODULE 1	MODULE 2
Feedstock:	type	visbroken tar	visbroken tar
	sulfur	5	5
	flowrate (metric tons/hour)	86	64
Gasifier:	type	WHB	WHB
	number	2	2
Gas turbine:	frame	GE9001FA	GE9001EC
	number	1	1
NOx control:	type	N ₂ dilution	N ₂ dilution
	ppm (15% O ₂)	25	25
Integration:	ASU air from turbine generator (%)	40	0
Air temperature (°C)		15	15
Cooling-water temperature (°C)		15	15
Power-delivery voltage		380 kV	380 kV

Table 2: IGCC-Module Performance

	MODULE 1	MODULE 2
Feedstock flow rate (metric tons/hour)	86	64
Feedstock lower heating value (kJ/kg)	38520	38520
Oxygen flow rate (as 100% O ₂ , metric tons/hour)	93.5	69.5
Thermal energy of feedstock (MWt)	920	683
Syngas from gasifiers (MWt)	759	563.5
Gasification efficiency (%)	82.5	83.5
Dry syngas to gas turbines (MWt)	741	549.5
Dry syngas to postfiring (MWt)	0	0
Syngas treatment efficiency (%)	97.5	97.5
Gas turbine gross power output (MWe)	286	215
Steam turbine gross power output (MWe) ¹	169.5	120.8
Expander gross power output (MWe)	5	3.7
Gross electric power output (MWe)	460.5	339.5
Process unit consumption (MWe)	3.2	2.5
Oxygen plant consumption (MWe)	44	42
Utility unit consumption (MWe)	6.5	5.5
Power island consumption (MWe)	3.8	3.5
Overall electric power consumption (MWe)	57.5	53.5
Net electric power output (MWe) ²	401	285
Net electrical efficiency (%)	43.5	41.6
Investment cost (US\$/kW)	1120	1220

¹ Steam turbine condensing pressure 0-032 bar (abs)

² 99.5% step-up transformer efficiency included

In general, such modules can be developed to meet the specific needs of a refinery by careful consideration of the following key design items:

- size and number of gasifiers
- gas-turbine frame model and number
- level of syngas postfiring in the heat-recovery steam generator (HRSG) associated with the gas turbine.

Design parameters for the two IGCC modules studied are given in Table 1. To evaluate the conversion of heavy oil to power more clearly, these modules have not been designed to coproduce hydrogen and steam. However, coproduction of hydrogen and steam can be easily added by either increasing oil throughput and leaving the power output unchanged, or by decreasing the power output and leaving the oil throughput unchanged.

Table 2 gives key performance data and the estimated investment cost per kilowatt (kW) of power produced. The investment estimates are based on European costs of 1998 and include all aspects of the complex with the exception of the cost of land.

Atmospheric emissions from the four modules would not exceed the following limits:

NO_x	50 mg/Nm³ (dry-15% O₂)
SO₂	10 mg/Nm³ (dry-15% O₂)
CO	<10 mg/Nm³ (dry-15% O₂)
Particulates	< 1 mg/Nm³ (dry-15% O₂)

Despite the poor quality of the feedstock, emissions are extremely low. Sulfur-capture efficiency, as ratio between recovered liquid sulfur and sulfur in the feedstock, is 99.7 percent.

For Module 1, the cost of producing electricity has been calculated based on the following assumptions:

Table 3: Bases for C.O.E.

Internal rate of return (IRR) on total investment	12% and 15%
Economical operating life	20 years
Equivalent availability	88%
Feedstock cost	20 US\$/metric ton
Operating personnel	4 million US\$/year
Maintenance cost (% of total investment)	3% per year
Chemicals	6 US\$ million/year
Interest during construction	8%
Construction period	3 years
Depreciation	10 years
Income tax	35%
Rate of inflation	0% per year
Insurance (% of total cost)	0.6% per year

Using these assumptions, the cost of electricity per kilowatt hour in U.S. cents, apportioned over major categories, is:

Table 4: Bases for C.O.E.

	12% IRR	15% IRR
Investment	2.29	2.76
Taxes	0.59	0.85
Feedstock	0.43	0.43
Maintenance	0.44	0.44
Chemicals	0.19	0.19
Personnel	0.13	0.13
Total	4.07	4.80

The market for petroleum products is shaped by many factors, and there is a wide range of options available to refiners for operating profitably under specific technical and economic conditions. Today, IGCC technology has become an attractive option for dealing effectively with the problem of residual high-sulfur fuel oil, a challenge faced by more and more refiners worldwide.

3. CIRCULATING FLUID BED (CFB)

CFB combustion involves the direct combustion of the heavy residue in a CFB boiler. Figure 2 is a simplified diagram of the overall process and Figure 3 shows the CFB boiler.

Figure 2: CFB Combustion Process

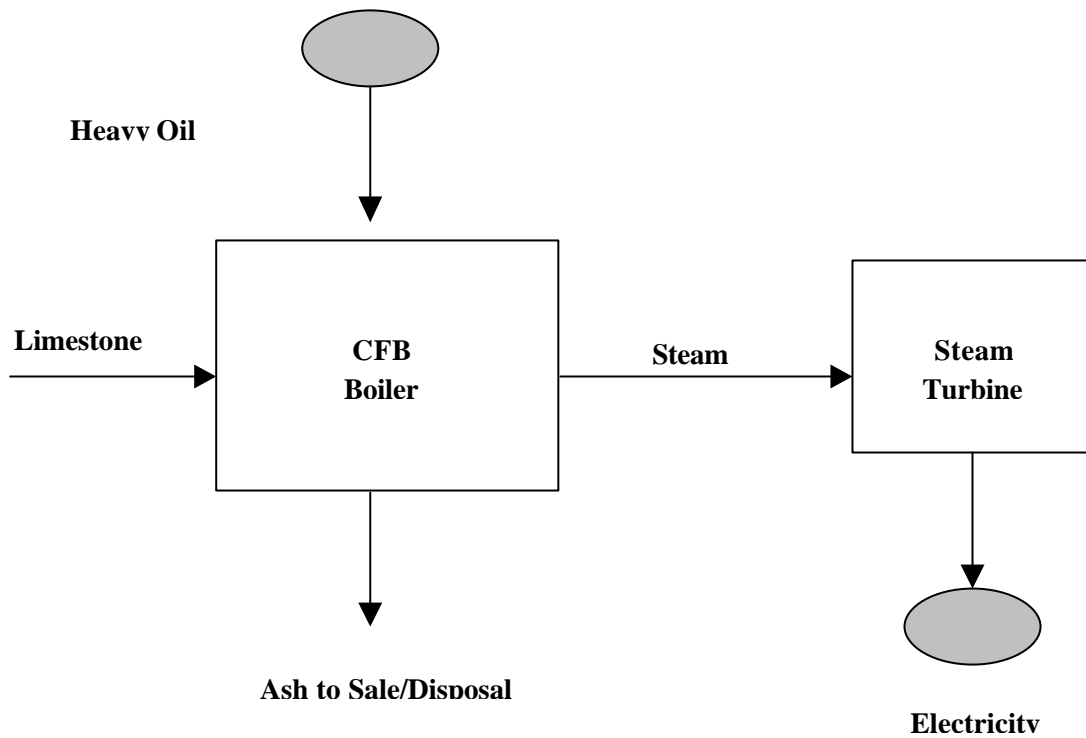
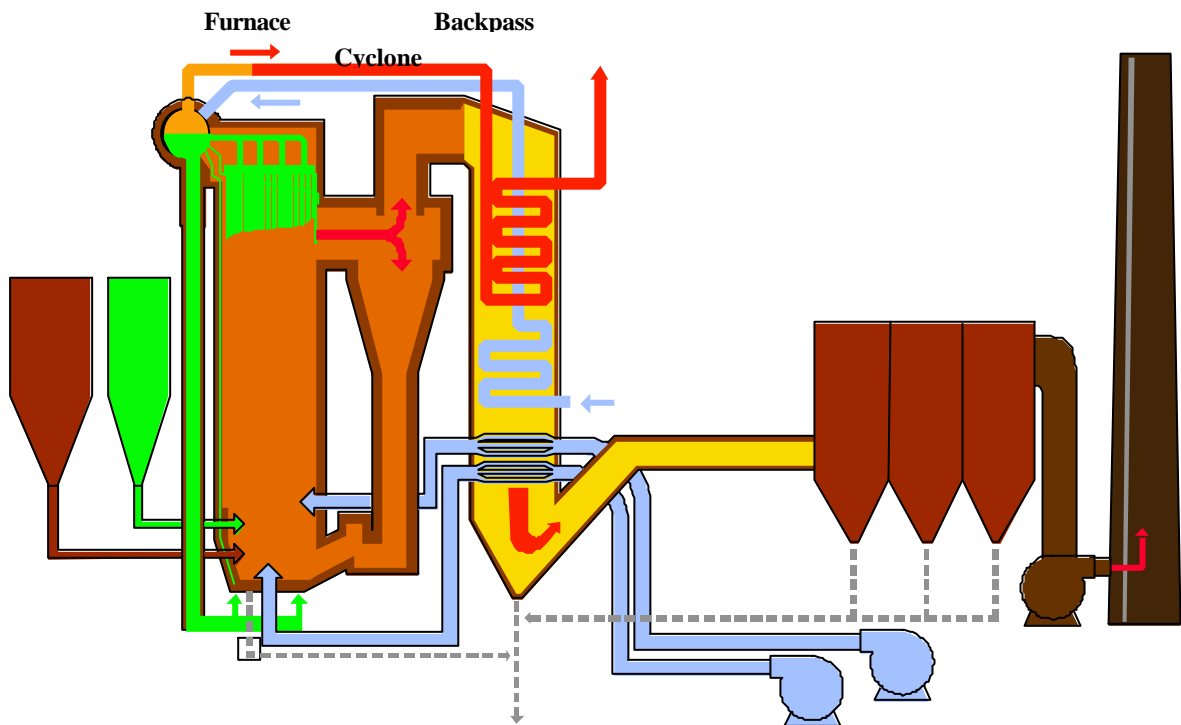


Figure 3: CFB Boiler System



In CFB combustion, the residue is fed to the furnace where it is burned in an upward-flowing stream of air. Crushed limestone is also fed to the furnace which is fluidized by the air. Heat transfer to the furnace walls maintains furnace temperature in the range of

800 - 900°C. A solids separator at the furnace gas outlet captures entrained solids and returns them to the lower furnace.

The above process offers the following advantages:

- ***Low Emissions***
The low furnace temperature provides for low NO_x emissions and for control of SO₂ emissions via limestone injection to the furnace.
- ***Low Operating Costs***
The high solids residence time and intense mixing within the furnace provide for high combustion efficiency and limestone utilization.
- ***Fuel Flexibility***
The low furnace temperature and hot circulating solids allow the CFB boiler to handle a wide range of fuels.

CFB technology is ideal for combustion of refinery residuals including petroleum coke and residual oils providing many advantages over other firing technologies. A typical analysis of petroleum coke is shown in Table 5 indicating this material is characterized by low volatiles, high sulfur and high vanadium content.

Table 5: Typical Delayed Coke Analysis

Moisture	1.0 - 10.0% by wt.
Volatiles	6.0 - 12.0
Ash	0.3 - 5.0
Sulfur	1.0 - 9.0
Vanadium	500 – 3000 ppm
HHV	7,800 – 8,300 kcal/kg

CFB technology can handle such fuels far better than any other combustion technology. The hot volatile content is accommodated by the large inventory of hot solids within the furnace. These hot solids provide a constant source of ignition energy and allow the boiler to operate over a wide range of loads without concern and without the need for higher grade support fuels. Fuel burnout has been demonstrated to be very high with CO levels very low, under all operating conditions. The high sulfur contents are accommodated by limestone injection into the furnace, where the limestone reacts with SO₂ to form gypsum. Furnace temperatures in the CFB are at the optimum for this reaction and sulfur removal rates of over 95% have been demonstrated with Ca/S ratios of about 2. The limestone injection system is simple, low cost and easy to control compared to wet or dry stack gas scrubbers. The high vanadium content is accommodated by the limestone injection, and by proper placement and design of superheater surface and refractory. The limestone reacts with the vanadium to form compounds with high melting points. Additionally, the vanadium actually helps the sulfur capture reactions by catalyzing the sulfur dioxide formed during combustion to sulfur trioxide which reacts much more readily with the limestone in the furnace.

A typical analysis of heavy residual oils is given in Table 6, indicating these materials are also characterized by high sulfur and vanadium content.

Table 6: Typical Residual Oil Analysis

Pour Point	45 – 140 °C
Viscosity	160 – 2780 cSt
Temperature for Viscosity	100 – 220 °C
Sulfur	3.6 – 6% by wt.
Vanadium	250 – 1200 ppm

In addition, residual oils typically have high viscosity. To fire such residuals in a conventional liquid-fuel boiler, the residual oil must be atomized. Heating to the temperatures needed to atomize will result in coking. As a result, these materials are usually blended with expensive cutter stock to reduce viscosity. However, in a CFB there is no need for atomization due to the intense mixing in the furnace. This allows the residual oil to be burned directly without the need for expensive cutter stock.

In summary, the CFB combustion process is ideal for firing fuels with the characteristics of petroleum coke and heavy residuals oils.

Petroleum coke was first fired in a commercial Foster Wheeler CFB in 1983. Since that time petroleum coke test burns have been carried out in more than 17 different commercial Foster Wheeler CFB boilers. Foster Wheeler has also consulted for petroleum coke test burns in two non-Foster Wheeler CFB units. Table 7 summarizes the performance results from this testing.

Table 7: Foster Wheeler Has Extensive Commercial Plant Experience With Petroleum Coke

No. Plants Tested	Fuel Composition	Test Results
17	Vol: 5.6 – 17% by Wt.	SO ₂ 70 – 800 ppm
	S: 1 – 5.6% by wt.	Ca/S 2.7 – 1.5
	Ash: 0.5 – 8.8% by wt.	NO _x 30 – 150 ppm
	Va: 500 – 3100 ppm	Comb. Eff. 95 – 99.5%

Based on the above testing, Foster Wheeler has sold many CFB's designed to fire 100% petroleum coke, as shown in Table 8.

Table 8: Foster Wheeler: Commercial Plant CFB Experience

Plant	Size (MWe)	% Coke Firing
Paper Company (SE U.S.)	1 x 32	100%
Hyundai Oil	1 x 25	100%
City of Manitowoc	1 x 20	100%
NISCO	2 x 110	100%
Paper Company (SE U.S.)	1 x 32	100%
Petrox	1 x 60	100%
Zhenhai	2 x 50	100%
Bay Shore	1 x 180	100%
JEA	2 x 300	100%
Calmat	1 x 20	65%
UNI	1 x 15	70%
Rumford Cogen.	2 x 40	30%
UDG	1 x 50	60%
Stockton Cogen.	1 x 50	25%
Mt. Poso	1 x 50	25%

This reference list represents over 75% of all petroleum coke-fired CFB's and

includes the following key projects;

- **2 x 110 MWe CFB's for the NISCO Project**
In operation since 1992, these are the largest operating petroleum coke-fired CFB's in the world.
- **1 x 60 MWe CFB for Petrox**
Operating since 1998, this project includes the addition of a coker and a petroleum coke-fired cogeneration plant for an existing refinery. This project combines Foster Wheeler's strength in coking and CFB technology in a way that brings significant benefits to the refinery.
- **2 x 300 MWe CFB's for JEA**
When placed in operation in mid 2001, these will be the worlds largest CFB's and the largest firing petroleum coke.

In addition, several CFB's designed for coal combustion have been able to take advantage of the fuel flexibility of this technology and burn high percentages of petroleum coke. These CFB's are also shown in Table 8.

Foster Wheeler also have experience of firing residuals in a commercial scale CFB. Our CFB licensee in France has supplied a 1 x 15 MWe CFB boiler to Samedith/COF, Marseilles, France. This boiler has been firing coal and high viscosity pitch (one kind of residual) since 1993. The pitch is heated, pumped to the boiler front wall and fired into the furnace using a proprietary design lance and the proportion of pitch is 50% by heat input. The boiler is operated such that the firing of pitch is base-loaded and load fluctuations are taken with coal. During weekends the boiler load is maintained at a minimum value by burning pitch alone. SO₂ emissions are controlled by limestone fed to the furnace. Boiler performance has been excellent, with low CO emission, low unburned carbon loss and no problems with coke formation. The plant reportedly plans to increase pitch firing capacity to enable full load operation on 100% pitch.

The economics of direct CFB combustion were calculated for cases similar to those described earlier for IGCC. CFB plant performance for each case is given in Table 9.

Table 9: CFB Plant Performance

	Plant 1	Plant 2
Feedstock Flow Rate (tons/hour)	86	64
Feedstock Lower Heating Value (kJ/kg)	38,520	38,520
Thermal Energy Feedstock (MWt)	920	683
Steam Turbine Gross Power Output (MWe)	384.7	290.0
Power Island Consumption (MWe)	39.0	29.0
Net Power Output (MWe)	350.7	261
Net Electrical Efficiency (%)	38.1	38.1
Investment Cost (US\$/kw)	890	970

The emissions will not exceed the following limits:

	<u>3% O₂</u>	<u>15% O₂</u>
NO _x	150 mg/Nm ³	50 mg/Nm ³
SO ₂ (95% removal)	400 mg/Nm ³	130 mg/Nm ³
CO	20 mg/Nm ³	< 10 mg/Nm ³
Particulates	50 mg/Nm ³	< 20 mg/Nm ³

Note that compared to the IGCC case, the NO_x and CO emissions above are similar while the SO₂ and particulate emissions are higher. SO₂ emissions can be reduced substantially if needed by either increasing limestone feed to the CFB or by adding a polishing flue gas scrubber.

For Plant 1, the cost of electricity has been calculated based on the assumptions described earlier for the IGCC cases, except for the following;

Equivalent Availability	90%
Operating Personnel	2.3 US\$ million/year
Maintenance Cost (% total investment)	2.4% / year
Chemicals (including limestone)	3.8 US\$ million/year
Solid residue disposal	2.5 \$/ton

These changes reflect the relative simplicity of CFB combustion vs IGCC.

Using these assumptions, the cost of electricity per kilowatt hour in U.S. cents, apportioned over major categories is shown in Table 10.

Table 10: C.O.E.

	12% IRR	15% IRR
Investment	1.85	2.23
Taxes, Insurance	0.46	0.66
Feedstock	0.49	0.49
Maintenance	0.27	0.27
Chemicals	0.14	0.14
Personnel	0.08	0.08
Solid resid. disposal	0.27	0.27
Total	3.56	4.14

4. TECHNOLOGY SELECTION

After presentation of IGCC and CFB, the question of which is the most appropriate, is fully justified.

Before answering this question it is important to table a few important general features of these two technologies.

- Zero fuel oil target: IGCC and CFB are the only available technologies meeting this target.
- Commercially demonstrated technologies: both, IGCC and CFB, are based on components and processes commercially demonstrated (see table 8 and 11).
- Feedstock flexibility: both, IGCC and CFB, can process any refinery residue, liquid or solid.
- Capital cost: IGCC and CFB are in general capital intensive. IGCC, being more complex is more costly and more sensitive to the economy of scale. In other words in the small-medium capacity range, say 300.000-500.000 t/y residue, the capex advantage of CFB becomes greater.
- Efficiency of conversion of residue to electricity: IGCC is based on combined cycle, thus achieves 40-44% efficiency, whereas CFB, being based on Rankine cycle, has lower efficiency, 34-38% depending on local conditions.
- Environmental performance: Atmospheric emissions of IGCC are lower. Sulphur capture efficiency is 95-98% for CFB and in excess of 99.5% for IGCC.
Liquid effluents produced by both technologies are limited in volume and can meet the most severe legal requirements.
With regard to solid effluents IGCC produce a relatively small volume of a metal concentrate, which can be used by the metallurgical industry for vanadium recovery.
CFB sulphur capture is based on limestone; the volume of limestone increases with the sulphur content of the feed and with the sulphur capture efficiency. The rejected spent limestone follows the same trend and can be disposed in different ways: landfill, aggregates for road construction and other major civil infrastructures, soil amendment. Limestone supply and spent solid disposal are important issues of any CFB project.
- Coproductions: IGCC produce, electricity and/or steam, and allows the coproduction of several syngas based chemicals: hydrogen, carbon monoxide, methanol, oxoalcohols etc.
CFB produces electricity and/or steam.

Coming back to the original question we have compared CFB and IGCC for different Clients and for different reference conditions. In all cases the choice of the most appropriate technology has been driven by project specific issues, amongst which the most important are: capacity, coproductions environmental regulations, feedstock characteristics, energy dispatch profile, limestone availability and cost, spent solid disposal and cooling water restrictions.

In conclusion there is not a simple general answer to the question of which technology is the most appropriate, but each project requires a comprehensive evaluation of all these project specific factors. Foster Wheeler is the world leader in CFB technology and has developed extensive engineering and construction skill in IGCC, so they are in an ideal position to provide a large mass of technical and economical data to permit a professional assessment of the most appropriate technology.

Table 11: Coal and Oil IGCC Projects

Project	Process	Power Output	Feed
Cool Water (California)	Texaco	100 MW	coal
Dow Plaquemine (Louisiana)	Destec	220 MW	coal
Demkolec (Netherlands)	Shell	250 MW	coal
Tampa Electric (1) (Florida)	Texaco	250 MW	coal
Texaco-Eldorado (Kansas)	Texaco	40 MW	petcoke
PSI-Wabash (1) (Indiana)	Destec	262 MW	coal
Schwarze/Pumpe (Germany)	Noell	40 MW	coal/oil
Shell Pernis (Netherlands)	Shell	127 MW+H ₂	heavy oil
SierraPacific (1) (Nevada)	KRW	80 MW	coal
Elcogas (Spain)	Prenflow	300 MW	coal/coke
ISAB (Italy)	Texaco	540 MW	asphalt
SARAS (Italy)	Texaco	550 MW	vb. tar
STAR (Delaware)	Texaco	240 MW	petcoke
API (Italy)	Texaco	250 MW	vb. tar
Fife Power (Scotland)	BGL	120 MW	coal/sludge
IBIL/Sanghi (India)	Tampella	60 MW	lignite
Fife Power (Scotland)	BGL	400 MW	coal/RdF

Note (1): Clean Coal Programs