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May 7, 1996

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Tallahassee

Ms. Blanca S. Bayo, Director
Division of Records and Reporting
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: Prudency Review to Determine Regulatory
Treatment of Tampa Electric Company's
Polk Unit; FPSC Docket No. 960409-EI

Dear Ms. Bayo:

Enclosed for filing in the above docket are the original and
fifteen (15) copies of each of the following:

1. Prepared Direct Testimony of Girard F. Anderson. 05109-96
2. Prepared Direct Testimony of Thomas F. Bechtel. 05110-96
3. Prepared Direct Testimony and Exhibit of Charles R. Black. 05111-96
4. Prepared Direct Testimony and Exhibit of Thomas L. Hernandez. 05112-96
5. Prepared Direct Testimony and Exhibit of John R. Rowe, Jr. 05113-96
6. Prepared Direct Testimony and Exhibit of Hugh W. Smith. 05114-96
7. Prepared Direct Testimony and Exhibit of Elizabeth A. Townes. 05115-96

Please acknowledge receipt and filing of the above by stamping
the duplicate copy of this letter and returning same to this
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TALLAHASSEE, FLORIDA

Ms. Blanca S. Bayo
May 7, 1996
Page Two

Thank you for your assistance in connection with this matter.

Sincerely,

A handwritten signature in dark ink, appearing to be 'Lee L. Willis', written over the word 'Sincerely,'.

Lee L. Willis

LLW/pp
Enclosures

cc: All Parties of Record (w/encls.)



3609
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TAMPA ELECTRIC COMPANY

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 960409-EI

TESTIMONY
AND EXHIBIT OF
CHARLES R. BLACK

DOCUMENT NUMBER-DATE

05111 MAY-78

FPSC-RECORDS/REPORTING



TAMPA ELECTRIC COMPANY

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 960409-EI

TESTIMONY
AND EXHIBIT OF
CHARLES R. BLACK

BEFORE THE PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

CHARLES R. BLACK

Q. Please state your name, address and occupation.

A. My name is Charles R. Black. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am Vice President Project Management for Tampa Electric Company.

Q. Mr. Black, please furnish a brief outline of your educational background and business experience.

A. I graduated from the University of South Florida in August, 1973 with a bachelor of science degree in Engineering, majoring in Chemical Engineering. I am a Registered Professional Engineer in the State of Florida. I began my career with Tampa Electric Company in September, 1973 as a staff engineer in the Production Department. Between 1973 and 1989, I held various engineering and management positions in the Production Department, Power Plant Engineering Department, and the Budget Department. In March of 1989, I joined our affiliated company, TECO Power Services as Director of Engineering and Construction. In

1 December of 1990, I was elected Vice President of
2 Engineering and Construction. In December of 1991, I
3 returned to Tampa Electric as Vice President of Project
4 Management.

5
6 Q. Have you previously testified before this Commission?

7
8 A. No.

9
10 Q. What is the purpose of your testimony?

11
12 A. The purpose of my testimony is to demonstrate that Polk
13 Unit One is a reasonable and prudent addition to Tampa
14 Electric's generating capability and that all costs
15 associated with this unit and the company's Polk Power
16 Station should be considered reasonable and prudent for
17 rate making purposes. In particular, I will describe the
18 costs of the various components of the Polk Power Station
19 including Polk Unit One. Principally, these include the
20 cost of the land acquired for the Polk site; the cost of
21 site development; and the cost of the Integrated
22 Gasification Combined Cycle (IGCC) Facilities. I will also
23 discuss the benefits of the fuel flexibility incorporated
24 into the IGCC Technology. The facts will show that the
25 Polk Power Station Project's first of a kind technology

1 will be put into service at a new site, on schedule, and
2 within 4.3% of the cost estimate provided to this
3 commission in the 1991 Need Hearing. This represents an
4 extremely successful project. These results demonstrate
5 that Tampa Electric's management of the project was
6 effective in controlling the project's technology, schedule
7 and cost.

8
9 Q. Have you prepared an exhibit in support of your testimony?

10
11 A. Yes, I have. My Exhibit No.____ (CRB-1) consisting of
12 twenty-seven documents was prepared under my direction and
13 supervision.

14
15 Q. What has been your role in the development of the Polk
16 Power Station?

17
18 A. In my current position as Vice President of Project
19 Management, I am responsible for all aspects of the
20 engineering, procurement, construction, start-up, cost and
21 schedule control for the entire Polk Power Station Project.

22
23 Q. Please provide a general description of the Polk Power
24 Station.

1 A. The Polk Power Station is being constructed in pursuant to
2 the determination of Need, Order No. PSC 92-0002-FOF-EI,
3 issued by this Commission March 2, 1992, in Docket No.
4 910885-EI. The Project is part of the U.S. Department of
5 Energy's (DOE) Clean Coal Technology Program. The DOE's
6 objective for the Polk Power Station Project project is to
7 demonstrate the high efficiency and low environmental
8 emissions of IGCC technology. The facility's capacity
9 rating is 250 MW. Tampa Electric expects to receive over
10 \$122 million from the DOE towards the construction of the
11 facility and \$20 million toward the operation and
12 maintenance of the unit during its first two years of
13 operation. The Polk Power Station site consists of
14 approximately 4,348 acres in Southwestern Polk County,
15 Florida. Document No. 13 of my Exhibit provides maps
16 showing the location of the Polk Power Station site.

17
18 Throughout the project, Tampa Electric has communicated
19 with the local community about our plans and activities
20 associated with the Polk Power Station. Tampa Electric has
21 earned very positive support from the local community as
22 well as Polk County government officials and business
23 leaders. As the Polk Power Station moves towards
24 operation, we continue to benefit from this support and
25 have committed to continue to seek the community's

1 involvement and support during the operation of the plant.

2
3 Q. Please describe the technology being implemented in Polk
4 Unit One.

5
6 A. The Polk Unit One will use Integrated Gasification
7 Combined Cycle technology (IGCC). This technology
8 integrates state-of-the-art environmental processes for
9 creating a clean fuel gas from a variety of feedstocks with
10 the efficiency benefits of combined cycle generation
11 equipment.

12
13 The primary components of the Polk IGCC technology are the
14 Texaco Gasification Process, the low temperature gas clean-
15 up system, the hot gas clean-up system provided by General
16 Electric Environmental Services, Inc.(GEESI), the air
17 separation unit provided by Air Products and Chemicals, the
18 sulfuric acid plant provided by Monsanto Enviro-Chem
19 Systems, Inc. and the power generation equipment being
20 provided by General Electric. All of the major components
21 of the plant, with the exception of the hot gas clean-up
22 system, are commercially available. These commercially
23 available components are being integrated in a unique
24 fashion at Polk Unit One resulting in a very high power
25 generation efficiency and very low environmental emissions.

1 Q. Please describe briefly how the technology works.

2
3 A. A general block diagram of the technology is included as
4 Document No. 14 of my exhibit. The fuel arrives at the
5 site via specially designed, totally enclosed trucks. It
6 is unloaded into the fuel storage silos. From the silos,
7 the fuel moves by conveyor to the fuel preparation building
8 where it is ground and mixed with water. This fuel/water
9 mixture is then pumped to the gasifier where it is combined
10 with oxygen. The oxygen is produced by the air separation
11 unit (ASU). The ASU takes ambient air and cools it to
12 about minus 300° F. At this temperature, air exists as a
13 liquid. The liquid air is sent to the distillation section
14 where the nitrogen is separated from the oxygen.

15
16 In the gasifier, the fuel and oxygen form a synthetic fuel
17 gas (syngas). The mineral matter in the fuel that does not
18 become part of the syngas is removed from the bottom of the
19 gasification section of the plant. This residual slag
20 material will be sold and used in the production of
21 asphalt, roofing shingles and sand blasting aggregate. The
22 syngas is then sent to the gas cleaning section of the
23 plant.

24
25 Polk Unit One has two separate gas cleaning technologies.

1 The first is a 100% capacity low temperature gas clean-up
2 system. This commercial technology is used to remove the
3 sulfur compounds from the syngas. The second technology is
4 a developmental hot gas clean-up system. This system is
5 sized to handle about 10% of the syngas flow. This
6 technology holds the promise of improved sulfur removal and
7 improvement in the overall unit's efficiency.

8
9 After the sulfur has been removed by both the low
10 temperature and hot gas clean-up systems, it is routed to
11 the sulfuric acid plant where it is recovered as commercial
12 grade sulfuric acid. This byproduct acid will be sold for
13 use in the phosphate industry.

14
15 After the syngas has been cleaned, it is sent to the
16 combustion turbine. In the combustion turbine, the syngas
17 is combusted and mixed with the nitrogen from the ASU. The
18 nitrogen injection is used to control NO_x emissions and to
19 increase the power output of the combustion turbine. After
20 the syngas is combusted, it enters the Heat Recovery Steam
21 Generator (HRSG). In the HRSG, the exhaust gas from the
22 combustion turbine generates steam, which is combined with
23 steam generated in the gasification section of the plant.
24 The steam then drives the steam turbine section of the
25 Combined Cycle Unit. The electricity from the combustion

1 turbine generator and the steam turbine generator is
2 increased in voltage and provided to the Tampa Electric
3 transmission system.
4

5 Q. How were the gasification systems and the power production
6 systems of Polk Unit One designed, engineered and
7 constructed as an integrated facility?
8

9 A. They were designed, engineered and constructed as an
10 integrated facility. From the initial conceptual design,
11 Polk Unit One has been engineered as an integrated
12 facility. The ultimate design of the unit has resulted in
13 a complex, very efficient integration of steam flows,
14 feedwater flows, oxygen and nitrogen flows between the
15 gasification section of the plant, and the power generation
16 portion of the plant. In addition, the plant control
17 systems are designed for integrated control of all areas of
18 the plant including the ASU, gasification, gas cleanup,
19 sulfuric acid production and power generation areas.
20

21 Q. Please describe the benefits Tampa Electric's Customers
22 will realize as a result of implementing IGCC Technology in
23 Polk Unit One.
24

25 A. Tampa Electric's Customers will realize many benefits as a

1 result of implementing IGCC Technology in Polk Unit One.
2 The IGCC Technology provides very high efficiencies with
3 very low environmental emissions. In fact, we expect Polk
4 Unit One to be one of the most efficient and cleanest coal
5 fueled plants in the world. Another significant benefit of
6 the IGCC Technology is its fuel flexibility.

7
8 Q. Please describe the benefits of this fuel flexibility.

9
10 A. The gasification portion of the plant is based upon
11 Texaco's proven commercially available gasification
12 technology. The Texaco gasification process, for solid
13 feedstocks, has been licensed in more than 15 commercial
14 facilities over the last 35 years for the production of
15 syngas. Texaco's technology is extremely flexible with
16 respect to the feedstock used to create the syngas. As
17 described in detail below the Texaco technology has
18 commercially processed feedstocks including a wide range of
19 coal (high and low sulfur), pet coke/coal blends of up to
20 over 90% pet coke, heavy oil, scrap tires, used oil,
21 plastics, and sewage sludge.

22
23 Document No. 15 of my exhibit is a Texaco marketing
24 brochure which provides a history of Texaco gasification
25 technology, a brief technical description of the Texaco

1 gasification process, a listing showing various feedstocks
2 previously used in Texaco gasifiers, and details of
3 previous installation of Texaco gasification systems.
4 Specifically, this brochure identifies pet coke as a viable
5 feedstock for Texaco gasifiers. The capability of the
6 Texaco Gasification System to utilize pet coke as a feed
7 stock has been specifically demonstrated at the Ube Ammonia
8 Plant in Japan. This plant has four Texaco gasifiers
9 utilizing pet coke and has been in operation using pet coke
10 since 1984.

11
12 Document Nos. 16-25 of my exhibit are various publications
13 that highlight the flexibility and benefits of the Texaco
14 gasification process.

15
16 The Cool Water plant, a 1000 ton per day facility located
17 near Daggett California, is described in the Texaco Coal
18 Gasification brochure Document No. 16 of my exhibit.

19
20 Document No. 17 of my exhibit is a Texaco paper presented
21 at the Pittsburgh Coal Conference in 1989. This paper
22 presents a summary of varying Cool Water operating data on
23 several different types of coal over the operating life of
24 the plant, including the ability of this plant to switch
25 feedstocks while the unit is on line and the ability to

1 blend coal with other fuels including waste streams such as
2 sewage sludge.

3
4 Document No. 18 of my exhibit is a paper presented by
5 Texaco at the 1991 New York Water Pollution Control
6 Association. This paper details the Texaco gasification
7 system capabilities of using the specific alternate fuel,
8 sewage sludge.

9
10 Document No. 19 of my exhibit is a Texaco brochure titled
11 Technology for Energy and the Environment. This brochure
12 discusses the fuel flexibility of the Texaco Gasification
13 Process in detail.

14
15 Document No. 20 of my exhibit is a list of awards earned by
16 the Texaco Coal Gasification Process and the Cool Water
17 Program.

18
19 Document No. 21 of my exhibit is a paper presented at the
20 1990 IEA expert meeting on the use of the Ube Coal
21 gasification slag, in the Netherlands. This paper explains
22 another benefit of the Texaco Gasification Process; that
23 being the production of a useable and saleable residual
24 slag while operating with a wide variety of solid
25 feedstocks.

1 Document No. 22 of my exhibit is a paper that was presented
2 by Texaco at the 1995 EPRI Gasification Conference in San
3 Francisco. This paper details Texaco's own internal use of
4 the Texaco Gasification Process which uses pet coke and
5 refinery waste as a feedstock.
6

7 Document No. 23 of my exhibit is a November 1, 1995 Texaco
8 announcement that they will be providing their Texaco
9 Gasification Process to Exxon for use at locations
10 throughout its refining and chemical business. In
11 addition, an agreement was also reached between Texaco and
12 Koch Refining Company to utilize the Texaco Gasification
13 Power System technology in a project which would gasify pet
14 coke to produce electric power, hydrogen, and steam at
15 Koch's Rosemont, Minnesota refinery.
16

17 As can be seen from the above, the Texaco gasification
18 process provides significant fuel flexibility which has
19 been amply demonstrated by many users for many years. This
20 will allow Tampa Electric to take advantage of low cost
21 feedstocks as they become available, providing additional
22 fuel savings to our Customers.
23

24 Additional references are provided in Document No. 24 of my
25 exhibit, a reference list of papers previously issued by

1 EPRI, concerning coal gasification and Document No. 25 of
2 my exhibits, a list of papers available from Texaco.
3

4 Q. Please provide a breakdown of all of the various costs
5 Tampa Electric projects it will have incurred in connection
6 with the Polk Power Station by the time Polk Unit One is
7 scheduled to be placed in commercial operation in October
8 of 1996.
9

10 A. We currently estimate a total expenditures of approximately
11 \$506,165,000 in total net capital costs for the Polk Power
12 Station by the time Polk Unit One is placed into service in
13 October 1996. Project to date expenditures through March,
14 1996 are \$439,804,000. As I will discuss later in my
15 testimony, in detail, the capital cost of the unit has
16 increased only 4.3%, which is essentially level from the
17 estimate provided at the Need Hearing when comparable costs
18 are examined.
19

20 Q. How did the capital cost estimate for the Polk Power
21 Station evolve from the Need Hearing estimate to your
22 current estimate?
23

24 A. Based on a consistent comparison which excludes the
25 estimated land acquisition costs, site development costs

1 and AFUDC expense, the comparative costs of Polk Unit One
2 have remained relatively unchanged (4.3% above the December
3 9, 1991 Need Hearing estimate). The Need Hearing estimate
4 was completed before any project specific engineering or
5 design work had been completed, as was the case with all
6 the estimates examined as alternatives. It should also be
7 noted that the design of this unit combines the innovative
8 integration of proven technologies with a developmental hot
9 gas cleanup process (HGCU) that offers potentially lower
10 unit heat rates and therefore lower operating costs. At
11 the time of the Need Hearing, only one IGCC electric power
12 generating unit had been built in the United States, and no
13 unit exactly like the Polk Unit One had ever been built.
14 The advancement of the integration and technology of the
15 unit is the primary reason DOE has provided funding for the
16 project, and the first of a kind design makes the
17 projection of costs more difficult.

18
19 Q. How was the initial estimate of \$413 million for Polk Unit
20 One developed?

21
22 A. The initial estimate of \$413 million was developed using,
23 primarily, capacity-factored and equipment-factored
24 estimating techniques. Capacity-factored estimating is
25 based on multiplying the cost of a similar unit for which

1 the direct construction costs are known by the ratio of the
2 new unit's capacity to that of the similar unit. Capacity
3 ratios are adjusted by an exponent chosen on the basis of
4 the unit type. Equipment-factored estimating is based on
5 the cost and specifications of each major equipment item
6 (vessels, compressors, turbines, exchangers, etc.). Costs
7 for bulk materials and field labor work-hour requirements
8 are factored, based on appropriate equipment parameters
9 (duty, size, weight, metallurgy, temperature, pressure,
10 etc.), to determine the total direct construction cost.
11 Such estimates have obvious limitations, but they are often
12 used to produce relative "Order of Magnitude" accuracy
13 comparisons. Expected accuracy ranges of total project
14 cost estimates tend to narrow as more information becomes
15 available throughout the life of any project.

16
17 Q. When and why was the project estimate updated?

18
19 A. The project estimate was updated annually and was used as
20 input to Tampa Electric's budget. In addition, these
21 updated estimates were used as the basis for our project
22 cost control process.

23
24 Q. How was the fall 1993 preliminary estimate prepared?

1 A. The fall 1993 preliminary estimate concentrated on the
2 scope and pricing of major equipment. Budget quotes were
3 obtained from prospective bidders to establish equipment
4 costs. Bulk materials and construction labor costs were
5 factored as a percentage of major equipment dollars based
6 on historical data. These more design-specific estimating
7 processes typically result in improved levels of accuracy.

8
9 Q. Please describe the fall 1994 estimate.

10
11 A. The fall 1994 estimate was much more detailed than previous
12 estimates and was based on planning studies, piping and
13 instrumentation diagrams, plot plans, electrical single
14 line diagrams, instrument index, equipment index, and civil
15 design drawings and sketches. Equipment pricing was based
16 on commitments and budget quotes. Large bore piping,
17 electrical, instrumentation, concrete, structural steel,
18 buildings, and earthwork estimates were based on quantity
19 take-offs and historical pricing data. Construction labor
20 work-hours were generated from take-off quantities and
21 priced out using 1994 labor rates and historical production
22 rates.

23
24 Q. Please describe the fall 1995 estimate.

1 A. The fall 1995 estimate was more detailed and relied more
2 heavily on actual contract commitment data and an
3 engineering estimate of work not yet under contract. At
4 the time of this update, the project was approximately 86%
5 committed. The acceptable industry standard of this type
6 of re-forecast would be +10% and -5%. Exhibit No. 26 of my
7 exhibit summarizes all of the Polk Unit One estimates
8 described above.

9
10 Q. What has Tampa Electric done to keep the cost of Polk Unit
11 One in line with the Need Determination Hearing estimate?
12

13 A. A primary objective of the Polk project management team has
14 always been to manage capital costs to their lowest
15 possible levels. Many scope modifications have taken place
16 as the project has evolved. A few of the significant
17 changes implemented to achieve a more cost-effective
18 project are listed in Document No. 27 of my exhibit.

19
20 In order to aggressively manage the Project's cost, Tampa
21 Electric implemented a change control process in which any
22 potential change to the Project's cost of \$25,000 or more
23 is identified and tracked. Any change that is ultimately
24 implemented must be reviewed and approved by me, in my
25 position as Tampa Electric's Vice President of Project

1 Management.

2
3 The capital costs have essentially remained level from the
4 estimate provided at the Need Hearing when comparable costs
5 were examined. The small 4.3% variance from 1991 Need
6 Hearing estimates to the 1995 definitive project re-
7 forecast is a significant achievement for the first-time
8 design and installation of a new technology such as an IGCC
9 power plant. If the start-up and check-out phase of the
10 project does not identify any new technological or
11 operational problems, the project management team expects
12 the comparable capital costs to remain within 5% of the
13 December 9, 1991 Need Hearing estimates, an enviable record
14 under the circumstances.

15
16 Q. Did Tampa Electric utilize innovative engineering,
17 construction and project management in the implementation
18 of the project?

19
20 A. Yes, we did.

21
22 Q. Please describe these innovations.

23
24 A. With regard to engineering, a major innovation was to
25 transfer a core team of Tampa Electric engineers to Houston

1 to work in the Architect/Engineer's (Bechtel Power Corp.)
2 project office. This minimized our internal engineering
3 personnel costs, as well as Bechtel's cost. It also
4 minimized the time required to complete the design by
5 eliminating submittal and turn around time for drawing
6 approvals. By utilizing a core of only a few people, Tampa
7 Electric was able to concentrate on the most significant
8 issues, thereby minimizing the additional engineering and
9 construction costs generally associated with incorporating
10 owner's comments. Other significant engineering
11 innovations were as follows:

12
13 1) We created a Technical Advisory Committee composed of
14 experts from Southern California Edison (operators of the
15 Cool Water Coal Gasification Facility), Tennessee Eastman
16 (company which uses Texaco coal gasification), Bechtel and
17 the major project participants to periodically review the
18 plant design and operation/maintenance issues. Several
19 important improvements came from this committee.

20
21 2) We used a three dimensional computer model to minimize
22 design interferences and associated construction network.

23
24 3) We used the "Walk Thru" module of the three dimensional
25 system to visually review the design for constructability,

1 operability and maintainability.

2
3 4) We implemented a design freeze at appropriate times to
4 minimize the preference changes common in later design
5 stages and to minimize the impact of late design changes on
6 construction costs.

7
8 5) We made critical reviews of installed spare equipment to
9 insure that only the equipment necessary to achieve project
10 goals was installed.

11
12 6) We made a prudent selection of design standards for
13 various equipment based on input from Texaco, Bechtel and
14 major suppliers to minimize equipment and construction
15 costs.

16
17 7) Texaco completed a series of optimization studies to
18 determine the best arrangement or design of major sub
19 systems of the plant. Examples include configuration of
20 syngas coolers, methods of sulfur removal from the syngas,
21 and requirements for nitrogen and oxygen storage.

22
23 With regard to construction, a major innovation was to hire
24 the Construction Manager early in the detail design effort
25 and have them coordinate a Constructability review program.

1 This program led to savings of more than \$10 million.

2
3 The Construction Management team also coordinated detailed
4 schedule and task analyses with the contractors and
5 engineers to minimize the potential for serious delays
6 which could have occurred in erection of critical
7 equipment. One noteworthy example of the success of this
8 process is the delivery and erection of the radiant syngas
9 cooler which required over one year of planning and
10 resulted in the installation of the 700 ton radiant syngas
11 cooler ahead of schedule.

12
13 With regard to project management, a major innovation was
14 the use of TECO Power Services for Project Management
15 Services. This provided necessary continuity with the
16 Department of Energy, as well as very talented senior
17 advanced technology experts to provide guidance. In
18 addition, the overall Project Team was designated from the
19 start to include all necessary departments of Tampa
20 Electric to assure all aspects of the new facility would be
21 coordinated to work within the existing Tampa Electric
22 system. This included the new station staff, which was
23 closely involved with design review. Development of
24 incentive based contracts for the Engineering Services and
25 the Construction Management Services, along with regular

1 cost and schedule reviews were also very instrumental in
2 helping to keep the project team focused on meeting goals.
3

4 Q. Why was the final Polk Power Station site selected?
5

6 A. As described in Mr. Anderson's testimony, the Company made
7 the decision that the plant should be located at an inland
8 site. Tampa Electric performed an engineering/economic
9 review of the three most promising inland sites recommended
10 by the Citizen's Siting Task Force. All three of these
11 sites were in the phosphate mining district of southwest
12 Polk County. The three sites were designated as the "Polk-
13 A", "Polk-1" and the "Polk-2" sites. The Polk-A site had
14 characteristics that were unique when compared to other
15 locations. The primary advantages of the Polk-A site were:
16

17 1) This site was large enough to support a Combined Cycle
18 facility and Base Load facilities and was under only two
19 ownerships.

20 2) The Property has a large block of unmined land close to
21 State Road 37 to support the power block facility.

22 3) The existing land use and zoning designation could be
23 modified by a conditional use permit for a power plant
24 facility.

25 4) There was existing state and county road infrastructure

1 on three sides of the plant site.

2 5) The current road system has a low volume of vehicle
3 use. The site had adjacent railroad access, and existing
4 Tampa Electric Company 230kv transmission corridors with
5 the ability to add future transmission corridor connection
6 points.

7 6) The plant site has a large supply of ground water
8 resources, high air quality, mined land available for
9 cooling reservoir use, wetland reclamation ability, storm
10 water management capability, and a surface water body for
11 plant wastewater discharges.

12
13 The conclusion of the review determined that the
14 development of the Polk-A site should result in \$25-30
15 million lower present value cost than the Polk-2 site, and
16 about \$50-60 million less than the Polk-1 site. The Polk-A
17 site was ultimately purchased.

18
19 Q. What was the procedure used to acquire the property?

20
21 A. Tampa Electric Company and Agrico Chemical Co., the
22 phosphate mining affiliate company of Freeport McMoRan
23 Partners, met several times to determine the impact of
24 Tampa Electric Company construction of a power plant with
25 their ongoing mining operation, future mining plans, and

1 their anticipated future development of their surrounding
2 land ownership.

3
4 After a determination that plans could be modified to
5 accommodate the power plant facility, preliminary appraisal
6 of the property was made by Tampa Electric Company and
7 negotiations continued.

8
9 As discussed in Mr. Anderson's testimony, the Citizen's
10 Siting Task Force activities were very public, being
11 reported on in both the print media and television. This
12 public knowledge that these three particular sites had been
13 recommended, significantly increased the perceived market
14 value of the property. In addition, Tampa Electric faced
15 scheduling pressures to obtain ownership control of the
16 site. Tampa Electric's Need Order from this commission was
17 conditioned upon Tampa Electric securing the DOE funding.
18 Control of the site was a condition precedent to Tampa
19 Electric securing the benefit of the DOE funding for its
20 Customers and novation of the DOE Cooperative Agreement
21 with Tampa Electric.

22
23 Therefore, obtaining ownership control of the site became
24 the critical path activity in order for the entire project
25 to move forward.

1 After difficult negotiations and discussions, a negotiated
2 settlement was reached that would accommodate the continued
3 mining by Agrico to remove the remaining phosphate mineral
4 on site, modify existing mining and reclamation plans, and
5 assist Tampa Electric with the modification of the
6 reclamation plans and Polk County conditional land use
7 permits to ensure the property could be developed into a
8 power plant facility.

9
10 Tampa Electric negotiated a purchase price of \$3500 per
11 acre for 3572 acres contingent upon receiving all necessary
12 approvals from all governing agencies for the development
13 of a power generating facility.

14
15 Tampa Electric negotiated with American Cyanamid Company
16 for an additional 775 acres contiguous to the north of the
17 plant site for a purchase price of \$4,700 per acre. This
18 property is to be used for transmission corridors, a
19 substation facility, and to allow Tampa Electric to
20 accomplish the necessary replacement of vegetation, and
21 buffering.

22
23 Q. Describe the costs associated with site development of the
24 Polk Power Station project and describe how they were
25 managed.

1 A. The Polk Power Station site consists of approximately 4,348
2 acres of land previously mined for phosphate, including
3 recently mined areas with water-filled mine cuts between
4 over-burden spoil piles, recently reclaimed areas and old
5 mined and unreclaimed areas.

6
7 In addition to the Florida Department of Environmental
8 Protection (FDEP) and the U.S. Environmental Protection
9 Agency (EPA), the DOE was also involved in the
10 environmental permitting of the site.

11
12 As described in Mr. Smith's testimony, the basic
13 requirements for site development were set by environmental
14 permit requirements and the technical requirements of the
15 IGCC facility. The most significant environmental
16 requirement, from a cost perspective, was mitigation of the
17 previously existing wetlands. The most significant
18 technical requirement was the need for a closed loop
19 cooling reservoir. Once these requirements were set, the
20 scope of work for the site development was determined.

21
22 The site development work was broken into two main contract
23 packages. One for the work east of State Road 37 (SR 37)
24 and one for the work west of SR 37. This separation of
25 work was required since IMC-Agrico had not completed mining

1 the property west of SR 37 at the time when work on the
2 east portion had to begin to support the project schedule.
3 All of the power plant equipment and cooling reservoir is
4 located east of SR 37. The property west of SR37 will be
5 used primarily to reestablish drainage flows, provide a
6 habitat area and for required wetland mitigation. Tampa
7 Electric was successful in obtaining lump sum construction
8 bids for both of these packages. This is significant since
9 approximately one-half of the site was under water at the
10 time of the bids. The lump sum approach transfers most of
11 the risk of uncertainty to the contractor. Both packages
12 were competitively bid. The contracts were awarded to the
13 low evaluated bidder.

14
15 Tampa Electric also pursued actions to reduce the cost of
16 site development after the permits were received. We are
17 currently working with the FDEP and Florida Game and Fresh
18 Water Fish Commission (FG & FWFC) to modify the reclamation
19 plan for the property west of SR 37. This modification
20 will configure the area as a fishing area managed by FG &
21 FWFC. If approved, as expected, this configuration will
22 also result in significantly lower cost for Tampa Electric
23 which we have reflected in our total project estimates.
24 This modification was initiated as a direct result of local
25 interest in a fishing area and to manage the total cost to

1 the lowest possible level.

2
3 Q. How much of the total cost for the Polk Power Station will
4 be for land acquisition and site development costs?

5
6 A. Our current estimate for land acquisition and site
7 development is \$65,835,000. The land costs are \$19,840,000
8 with \$45,995,000 required for site development.

9
10 Q. Please describe the DOE's involvement in the Polk Power
11 Station Project.

12
13 A. The DOE's involvement with the Polk Power Station Project
14 was initiated as a result of the Clean Coal Technology
15 Program authorized by Public Law 98-473. This program has
16 involved five nationwide competitive solicitations
17 conducted over a period of nine years. At the end of the
18 five originally planned solicitations, a total of forty-
19 five projects, valued at more than \$7.14 billion had been
20 selected for government cost sharing.

21
22 Polk Unit One had its genesis as a project selected in the
23 Round III solicitation. The objective of Round III
24 projects was to implement cost-shared Clean Coal Technology
25 projects to demonstrate innovative, energy-efficient

1 technologies capable of being commercialized in the 1990s.
2 These technologies were to be capable of (1) achieving
3 significant reductions in emissions of SO₂ and/or NO_x and/or
4 (2) providing for future energy needs in an environmentally
5 acceptable manner. DOE's prime consideration in evaluating
6 and selecting Round III projects was to determine those
7 proposals that offered the greatest likelihood of
8 successfully demonstrating and, subsequently,
9 commercializing clean coal technologies. DOE rated
10 technical, commercial, environmental, cost, and finance
11 issues for each project independently against pre-
12 established evaluation criteria, then selected the highest
13 ranked projects for award. In this round, thirteen
14 projects were selected for receiving a total of
15 \$575,000,000 from DOE for necessary expense associated with
16 these clean coal technology demonstration projects. The
17 projects were to be cost-shared, with industry sharing at
18 least fifty percent of the project costs.

19
20 In August of 1989, TECO Power Services (TPS) and its
21 partner submitted a proposal in response to the Round III
22 solicitation. The proposed project was to be a 120 MW
23 integrated gasification combined cycle (IGCC) project using
24 a Lurgi air-blown fixed bed gasifier and in-line hot gas
25 clean-up (HGCU) system. In January, 1990, DOE notified TPS

1 and its partner that their project had been selected for
2 DOE cost-sharing of fifty percent of the \$240,000,000 total
3 project cost. After more than one year of intense
4 negotiations, the Cooperative Agreement was finalized with
5 DOE in March, 1991.

6
7 Shortly after completing the Cooperative Agreement, it
8 became apparent that it would not be possible to conclude
9 the necessary Power Sales Agreement (PSA) with the
10 originally proposed power purchaser. After many months of
11 trying to find a new site for the project, acceptable to
12 DOE, TPS bought out the interest of its partner and became
13 the sole "Participant."

14
15 In order to make the DOE project more reliable and
16 financially, environmentally, and strategically more
17 attractive to a prospective power purchaser, TPS developed
18 a concept whereby the originally conceived project would be
19 converted to a 250 MW IGCC using a Texaco oxygen-blown
20 gasifier, a General Electric (GE) 7F combustion turbine
21 (CT) and a parallel HFCU which would not restrict the
22 unit's overall availability. The new arrangement would
23 significantly reduce air and water emissions, improve
24 overall unit efficiency, and make the unit more competitive
25 in the power sales markets. Because of these major

1 improvements, DOE approved the project modification with
2 the main restriction being that their total dollars for
3 project cost sharing be maintained at the original
4 \$120,000,000 with a cap of twenty-five percent for
5 anticipated project scope growth.

6
7 As a result of these studies, Tampa Electric decided that
8 it would result in the most cost-effective alternative to
9 satisfy the projected need for capacity for Tampa
10 Electric's customers to assume control of the DOE project.
11 After demonstrating the merits of this new arrangement, DOE
12 approved the new project configuration, size and ownership
13 change by novation to the Cooperative Agreement on March
14 19, 1992.

15
16 The DOE funding is committed by Budget Period. For our
17 Project, Budget Period I consisted of the preliminary
18 Engineering and Environmental Assessments. Budget Period
19 II includes final engineering equipment purchases,
20 construction of the facility and final startup and
21 commissioning of the plant. Budget Period III is the DOE
22 Demonstration Period.

23
24 Currently all DOE funding has been obligated for Budget
25 Periods I and II. The total funding obligated by DOE to

1 date is \$122,894,000. This obligation secures all
2 necessary DOE funding through the construction and startup
3 of the plant.

4
5 Budget Period III DOE funding will be obligated upon
6 approval by the DOE of Tampa Electric's continuation
7 application. This application will be submitted in the
8 third quarter of 1996. Approval of Tampa Electric's Budget
9 Period III continuation application will secure the
10 \$20,100,000 to be used by the DOE to fund operations and
11 maintenance expenses during the first two years of
12 operation.

13
14 DOE has provided continuous monitoring of the costs
15 associated with the Polk Power Station Project. Tampa
16 Electric is required to submit monthly, quarterly, and
17 annual reports to DOE on the project's progress and cost
18 expenditures. The monthly reports summarize the project
19 status, accomplishments, planned and actual costs on a
20 cumulative basis, problems or issues, and plans for the
21 next month. In addition, DOE conducts an annual audit of
22 our expenditure and accounting policies.

23
24 There is a statutory provision contained in public law 99-
25 190 - Dec. 19, 1985- 99STAT.1251 that recognizes the risk

1 involved in first-of-a-kind demonstration by allowing for
2 cost growth. Because of the developmental nature of these
3 projects, DOE specifically provided for cost growth for
4 each of the projects in the Clean Coal Technology Program.
5 Cost sharing is limited on the Polk Project to \$120,000,000
6 plus twenty-five percent for expected project growth. DOE
7 has thoroughly monitored, reviewed and approved each
8 element of project cost growth as it occurred, and to date
9 DOE has approved over \$22,000,000 of additional capital
10 cost funding for the project. The requirements of the
11 Cooperative Agreement state that DOE is not obligated to
12 approve cost growth, and will only approve such growth if
13 it is necessary for the project's success and if the growth
14 has been prudently managed by the Participant, Tampa
15 Electric. Additionally, DOE will consider cost-sharing a
16 cost growth item only if the demonstration project has a
17 positive potential for market penetration and if it is
18 consistent with the original selection criteria.

19
20 Part of the original Cooperative Agreement lists certain
21 major equipment and construction contracts as Surveillance
22 Contracts. Surveillance Contracts by definition are large
23 critical parts of the project for which DOE maintains the
24 right of prior review and approval before implementation by
25 Tampa Electric. DOE's Surveillance Contract review

1 considered cost appropriateness, consistency with
2 requirements of the Cooperative Agreement, and overall
3 impact to the project's cost, schedule, and technical
4 success. All of these Surveillance Contracts were approved
5 by DOE. These contracts include purchase of the Texaco
6 gasifier, licensing agreement, architect/engineer sub-
7 contract, TPS subcontract for project management and
8 commercialization, fuel transportation contract, air
9 separation unit subcontract, slag and sulfur byproduct
10 contracts, environmental services subcontract, GEESI hot-
11 gas clean-up subcontract, combined cycle subcontract
12 utilizing a GE combustion turbine, administrative services,
13 operation and maintenance services, balance of plant
14 engineering services, fuel supply, and tail gas processing.

15
16 DOE also maintained continuous technical surveillance of
17 the progress of the project. At least once per year, DOE
18 has conducted an intensive review of the complete project.
19 During these reviews, DOE came to various project offices
20 and thoroughly reviewed the engineering and construction
21 status to confirm the project's specific performance and
22 adherence to requirements stated in the Cooperative
23 Agreement related to cost, schedule, performance and
24 marketability. All of these reviews resulted in Tampa
25 Electric satisfying all DOE needs and requirements.

1 Once each year, Tampa Electric project management personnel
2 made a detailed presentation to the DOE management staff in
3 Morgantown, West Virginia. These presentations provided an
4 in-depth status of all aspects of the Polk IGCC project.
5

6 In addition to the technical audits performed by DOE
7 project personnel, DOE also commissioned the Defense
8 Contract Audit Agency to perform periodic financial audits
9 of the books and records of Tampa Electric. These audits
10 verified TEC's use of appropriate accounting policies and
11 practices and confirmed compliance with government
12 requirements for this project and general government
13 auditing policies. All audits provided sufficient and
14 satisfactory results to the DOE.
15

16 In summary, DOE's involvement in the project has been to
17 continuously monitor all aspects of the technical,
18 financial, environmental, physical design and construction
19 of the project. These reviews have insured DOE that this
20 project is prudently being built from their perspective and
21 will satisfy the requirements of the Cooperative Agreement
22 and the Clean Coal Technology Program. The results of
23 these reviews confirm prudent project management by Tampa
24 Electric, and they also confirmed the technical, financial,
25 commercial, and environmental viability of IGCC in support

1 of making available an alternative power generation
2 technology for the U.S. Utility Industry.
3

4 Q. What are the DOE's objectives in the Polk Power Station
5 Project?
6

7 A. The DOE Clean Coal Technology Program is expected to be an
8 excellent mechanism for merging public and private sector
9 interests to protect the environment, reduce the cost of
10 environmental compliance, create jobs, and position U.S.
11 based business to compete successfully in the international
12 marketplace. It is designed to accelerate the progress of
13 clean coal technologies from the laboratory to the
14 marketplace by providing a financial bridge between the
15 economics of today and those of the future. The Clean Coal
16 Technology Program is focused on the development of new
17 technologies that can fulfill future utility expansion
18 plans and the stringent year 2000 Phase II emission limits
19 under the Clean Air Act Amendments (CAAA) of 1990.
20

21 As described in Mr. Bechtel's testimony, the primary
22 objective for the DOE for this project is to conduct a cost
23 shared project that will demonstrate oxygen-blown,
24 entrained-flow Integrated Gasification Combined Cycle
25 (IGCC) Technology on a commercial sized unit at a

1 greenfield site.

2
3 The technical objective of DOE is to demonstrate that IGCC
4 Technology can achieve significant reductions in SO₂ and NO_x
5 emissions when compared to existing and future coal-burning
6 power plants. In addition, this project is expected to
7 demonstrate the technical and commercial feasibility of a
8 utility scale IGCC with hot gas clean-up technology.

9
10 IGCC technology is expected to be the most economical,
11 cleanest environmental power generating method for the next
12 generation. It will use coal, the United States' most
13 abundant and economical fuel resource.

14
15 It is expected that successful demonstration of Clean Coal
16 Technology like the Polk IGCC Project will create world
17 wide demand for the technical know how developed in the
18 Clean Coal Technology Program, plus create demand for the
19 hardware, developed via this demonstration, such as the
20 American-made GE 7F Combustion Turbine.

21
22 Q. Was Tampa Electric able to secure additional funding from
23 the DOE after the inception of the project?

24
25 A. Yes. As described previously, in order to obtain

1 additional funding, Tampa Electric was required to make a
2 formal submittal requesting the additional funds,
3 specifying the necessity of, and benefit from, and the
4 causes of the cost growth. Each of the cost growth items
5 then required internal review by DOE to confirm that the
6 cost growth items were prudent, cost shareable, and met the
7 original project selection criteria related to programmatic
8 contractual, technical, environmental, commercial,
9 financial, cost, and market factors. A formal modification
10 of the Cooperative Agreement to authorize additional funds
11 was then issued.

12
13 In order to obtain DOE's approval, it was necessary for
14 Tampa Electric to demonstrate that the additional funds
15 were actually required and associated with a specific
16 element of the project that had been determined to be a
17 cost sharable item.

18
19 As a result of the above noted process, DOE has approved
20 three (3) separate modifications to the Cooperative
21 Agreement. These modifications totaled \$22,000,000. DOE's
22 approval signifies that DOE confirmed the changes were
23 justified, prudent, and required for the completion of the
24 project.

1 Q. Are there other examples of Tampa Electric working with the
2 DOE to control the project cost?

3
4 A. Yes, there are numerous examples of Tampa Electric working
5 with DOE to control project costs. Specific examples,
6 described in detail below include the DOE providing a
7 start-up charge of Hot Gas Cleanup (HGCU) Sorbent¹ valued
8 at \$1,000,000, flexibility in sourcing of materials and
9 cooperation to secure environmental permits to maintain our
10 schedule.

11
12 One example of Tampa Electric and DOE working together to
13 reduce project cost is related to the HGCU sorbent
14 development. The HGCU system is based on utilization of
15 a metal oxide sorbent for capture of sulfur from the syngas
16 produced in the gasification process. Like the overall
17 HGCU configuration development, the sorbent has been
18 undergoing research and development for at least 10 years.
19 DOE is funding another project with another contractor to
20 develop a sorbent which could be used in the Polk Project.
21 However, the development of a suitable sorbent has fallen
22 well behind the schedule required to support the Polk
23 start-up. In fact, the sorbent development was so late
24 that it appeared it would not be practical to start-up the
25 HGCU system until well after the start-up of the Polk unit

1 causing considerable added expenses and schedule problems.
2 Tampa Electric and DOE worked together to generate a plan
3 that called for DOE supplying an additional \$1,000,000 to
4 procure a "start-up charge" of sorbent which would allow TEC
5 to mechanically check-out the HGCU and to proceed in
6 parallel with the rest of the unit and allow development of
7 the operational sorbent to continue on another path. This
8 additional \$1,000,000 was over and above the funding being
9 received through the Clean Coal Technology Program. This
10 arrangement permitted completion of the HGCU checkout and
11 prevented Tampa Electric and DOE from being exposed to
12 considerable additional expense to come back later and do
13 the HGCU checkout while the rest of Polk was already in
14 operation. It also eliminated a potential safety and
15 reliability problem of checking out a major system while
16 the main unit adjacent to the HGCU was in operation.

17
18 An additional example is the procurement sourcing of
19 materials. The Clean Coal Technology Program was
20 originally intended to require utilization of predominantly
21 domestic design and equipment. However, due to the
22 economic collapse of many domestic foundries and
23 manufacturing facilities, many of the IGCC components
24 either were not available from US suppliers or were overly
25 expensive. Tampa Electric did an extensive review of world

1 wide availability of suppliers for sophisticated and
2 complex equipment, such as the radiant syngas cooler, which
3 cools the gas exiting the gasifier from 2500°F to about
4 1400°F . What Tampa Electric found was that domestic
5 supply of this equipment would be about \$10,000,000 more
6 expensive than foreign supply. DOE and Tampa Electric
7 worked to overcome this hurdle and the foreign supplied
8 equipment was approved. In addition, this has led to DOE
9 altering its domestic use position, and has resulted in DOE
10 marketing the products from the Clean Coal Technology
11 Program worldwide, thereby actually increasing
12 significantly the utilization of United States technology,
13 equipment and manpower to support this new worldwide
14 market.

15
16 Another example is that the original project plan for DOE
17 contemplated that DOE would act as the lead federal agency
18 for completing the required permits for Polk Power Station.
19 After the project started, it was determined that the
20 complexity of coordination for this effort would tax DOE
21 beyond their limits and if an alternative arrangement was
22 not developed, the project's permitting and subsequent in
23 service date would be delayed about a year. This would cost
24 DOE and Tampa Electric substantial sums of money. Tampa
25 Electric and DOE worked diligently together and a plan was

1 implemented to transfer lead agency status to the
2 Environmental Protection Agency.

3
4 These project cost savings, jointly supported by Tampa
5 Electric and DOE demonstrated both Tampa Electric's and
6 DOE's desire and commitment to minimize overall project
7 costs for Tampa Electric and its Customers while developing
8 a cost effective future Clean Coal Technology for DOE.

9
10 Q. How were cash flows managed on the Polk Power Station
11 project?

12
13 A. In an effort to meet the project's objective of minimizing
14 total project costs, cash flow considerations and their
15 effect on AFUDC were closely managed. Two examples of this
16 cost control effort can be shown by the project's prompt
17 retrieval of available DOE funding and its procurement
18 policy, to review alternative payment options for all
19 material purchases and construction contracts.

20
21 DOE cost share reimbursements were limited to established
22 percentages for costs within various areas of the plant and
23 could only be done on an As-Paid basis. Each month Tampa
24 Electric makes a detailed review of Project-to-Date
25 expenditures and prepares a cash call to the DOE shortly

1 after the completion of the corporate month end General
2 Accounting close-out. A cash call is prepared
3 independently by two individuals within the project
4 organization based on the corporate general ledger detail
5 and specific guidelines and percentages dictated by the
6 DOE. In addition to month-end cash calls, Tampa Electric
7 also executes interim cash calls for major payments made to
8 vendors and contractors prior to the month-end cash calls.
9 These prompt DOE cash reimbursements have helped minimize
10 total project costs by reducing Tampa Electric's AFUDC.
11

12 The project's procurement policy for all major material
13 purchases also had a positive effect on the project's cash
14 flow and overall cost objectives. Each material order's
15 base option was to pay vendors 100% of order value at time
16 of receipt of material in field. The option of alternative
17 progress payment schedules was provided to each prospective
18 bidder for major equipment orders. These alternatives were
19 evaluated by the project's Materials Management staff
20 utilizing a computerized spread sheet from Tampa Electric's
21 Treasury Department which calculated the effect of the
22 project's AFUDC based on all vendor payment options
23 presented. If the vendor's "Cost of Money" reductions in
24 overall costs for a progress payment option were greater
25 than the calculated project AFUDC increases, the order

1 would be placed utilizing the progress payment option,
2 resulting in a net project savings. Conversely, if the
3 progress payment option decreases weren't enough to offset
4 Tampa Electric AFUDC expenses, the base option of 100% at
5 receipt would be utilized. As a general rule, the project,
6 whenever possible, deferred expenditures to the latest
7 possible date if they resulted in reducing overall project
8 costs.

9
10 Q. How were purchasing decisions made on the Polk Power
11 Station Project?

12
13 A. Tampa Electric's Materials Management organization has
14 managed and continues to manage purchasing for the Polk
15 Power Station Unit 1 Project. Consistent with this
16 management arrangement, these activities are administered
17 in accordance with Project-specific procedures modeled
18 after Tampa Electric's standard operating procedures.

19
20 Competitive bidding to identify a lowest evaluated bidder
21 was used in virtually all Project procurement transactions
22 including Architectural/Engineering Services, Construction
23 Management, major construction packages, major equipment
24 purchases, and routine purchases of materials and
25 services. In a limited number of situations it was

1 necessary to use other criteria. For example, a sole-
2 source, negotiated purchase was the alternative in
3 situations where suppliers hold proprietary rights to
4 equipment or processes.

5
6 The vast majority of purchasing transactions on the Project
7 were and continue to be competitively bid to multiple
8 prospective bidders. And, depending on the nature of the
9 particular equipment or service, data base resources of
10 Tampa Electric, the Engineer, the Construction Manager, and
11 the other project participants were used to identify
12 prospective bidders.

13
14 Communications between the Project and prospective bidders
15 between issuance of Invitations For Bid and receipt of
16 sealed bids were always administered by assigned
17 representatives of the Materials Management organization.
18 Sealed bids were received by Materials Management and
19 opened in the presence of witnesses. The Engineer received
20 unpriced bids from which an initial technical evaluation
21 was developed. The Materials Management organization had
22 responsibility for the commercial evaluation. As the
23 technical and commercial evaluations progressed,
24 clarifications would be solicited from the respondents, as
25 necessary, and factored into the evaluations. These

1 evaluations then became integrated into a consensus
2 document called a Request for Commitment Approval (RCA).
3 The RCA was routed to the appropriate management levels for
4 approvals necessary to carry out the award recommendations.
5

6 Q. Has the Florida Public Service Commission conducted any
7 audits of the Polk Power Station Project?
8

9 A. The Florida Public Service Commission conducted an audit
10 (Control No. 94-014-2-1) "...to determine if procedures
11 were in place to control the bidding and awarding of
12 contracts between Bechtel Power Corporation and Tampa
13 Electric Company." The audit opinion stated "Tampa Electric
14 Company's formal and informal internal procedures are
15 sufficient to control the bidding and awarding of the
16 audited contracts." Field work for the audit commenced on
17 January 27, 1994. The last day of field work was June 16,
18 1994, the date of the audit exit conference.
19

20 Q. Were minority contractors utilized on the Polk Power
21 Station Project?
22

23 A. Yes. Tampa Electric and Bechtel have employed their
24 minority business enterprise programs throughout the
25 procurement process for the Polk Power Station Project to

1 insure opportunities for these firms. Examples of the
2 positive efforts to include minority, small, and women-
3 owned businesses in construction of the Polk Power Station
4 include:

5
6 Minority, small, and women-owned businesses have been
7 awarded over 550 (39%) of 1,412 equipment orders and
8 services contracts.

9
10 Minority, small, and women-owned businesses have
11 received equipment orders and services contracts
12 totaling over \$26.8 million.

13
14 Awards to minority, small, and women-owned businesses
15 have included, but are not limited to, the following:
16 materials and equipment; engineering services;
17 precision machining; certification services; building
18 construction; transportation services; and roadway
19 surfacing.

20
21 Q. Did Tampa Electric utilize any innovative contracting
22 approaches on the Polk Power Station Project?

23
24 A. Yes. Tampa Electric has used incentive provisions and
25 turnkey contracting approaches on the Polk Power Station

1 Project.

2
3 Tampa Electric has successfully encouraged bidders to
4 propos~~e~~ and agree to various incentive provisions. For
5 example, both the Architectural/Engineering and
6 Construction Management contracts include fee-at-risk
7 incentive provisions which serve to encourage improvement
8 in Project costs, schedule, plant operating performance,
9 and teamwork. Other incentive arrangements with Project
10 contractors have derived numerous suggestions for cost
11 savings and process improvements.

12
13 Turnkey contracting has been a very effective contracting
14 option for the Project. This was particularly evident in
15 execution of the competitively awarded turnkey contracts
16 for the Air Separation Plant and Sulfuric Acid Plant by Air
17 Products and Monsanto Enviro-Chem, respectively. In these
18 cases Air Products and Monsanto Enviro-Chem had
19 responsibility for all aspects of the design, engineering,
20 supply, construction, and commissioning of their respective
21 plants. The Project maintained responsibility for general
22 oversight of the work carried out within the battery limits
23 and design of plant interfaces. This provided for expertly
24 designed and constructed plants by the successful
25 contractors and optimum utilization of Tampa Electric's

1 Project resources.

2
3 Q. How was safety managed on the Polk Power Station Project?

4
5 A. Early in the team building meetings, it was recognized by
6 the Project participants that safety was of primary
7 importance in the execution of the construction program.
8 It is well documented by leading construction industry
9 organizations (Construction Industry Institute, National
10 Business Roundtable and others) that safe work practices
11 lead to more productive construction sites. With this in
12 mind the Project team set a goal of having an OSHA
13 recordable rate of 3.5 or less. The OSHA recordable rate
14 is the average number of defined injuries per 200,000 work-
15 hours. The national average for heavy industrial work is
16 greater than 10. To achieve this goal, the following were
17 implemented for the construction program:

18
19 1. When prequalifying construction contractors to bid on
20 the project only firms whose Experience Modification
21 Rate (EMR) was 1.0 or less were considered. An EMR of
22 1.0 represents the average rate for the particular
23 industry or type of work the contractor does. By
24 doing this we only considered better than average
25 companies.

1 2. The construction manager's (Bechtel Power Corporation)
2 zero accident policy and procedure were incorporated
3 into the Construction Contract documents.

4
5 3. The site safety manager was given the responsibility
6 and the authority to enforce the provisions of the
7 safety program. This was done using the Safety
8 Prevention and Recognition team. This concept
9 required all contractors to participate in the
10 construction safety program. Rewards were given to
11 site individuals for individual safety achievement.

12
13 4. Incentives were made a part of each major construction
14 contract. In this incentive program contractors had
15 part of their contract price dependent on how well
16 they participated in the safety program and what
17 performance they achieved. A considerable part of the
18 construction manager's fee was placed at risk,
19 depending on the goals reached during construction of
20 Polk Unit One.

21
22 By using all of the above strategies, a team concept and
23 commitment to the safety of all workers has been achieved
24 at the Polk Unit One.

1 Q. What was Tampa Electric's approach to Workers' Compensation
2 Insurance for the Polk Power Station Project?

3
4 A. After the Polk Power Team had set goals for safety on the
5 project, TEC reviewed the concept of supplying an Owners
6 Controlled Insurance Program (OCIP). Tampa Electric had
7 Davis Baldwin Insurance Brokers review the project safety
8 program to determine what, if any, effect it may have on
9 the cost to contractors to provide the Workers'
10 Compensation Insurance. Davis Baldwin felt, and TEC
11 agreed, the aggressive program would lead to actual cost
12 being much less than industry averages. TEC then selected
13 the Hartford as the carrier for the Workers' Compensation
14 program. After Hartford was selected, a representative of
15 their company was assigned to the project team in the
16 field. This allowed for close communication and teamwork
17 for all aspects of the Workers' Compensation insurance. By
18 using Hartford's resources and skills in claim management,
19 a drug free workplace and a highly visible management staff
20 in the field, we have been able to control workers'
21 compensation cost very effectively.

22
23 Q. What have been the results of the safety programs to date?

24
25 A. 1. As of April 21, 1996 the project has incurred two (2)

1 lost time accidents with over 3 Million work-hours
2 completed. This included 1.7 million consecutive
3 work-hours without a lost time accident. We have
4 recently completed an additional 1,000,000 work-hours
5 with no lost time accidents. This is an outstanding
6 record.

7
8 2. The OSHA recordable rate for the project is below 2.0
9 versus an industry average greater than 10.0.

10
11 3. The actual cost of injuries to workers covered under
12 the OCIP is less than 10 cents per work-hour vs.
13 Industry averages of \$1.00 to \$1.50 per work-hour.

14
15 By all measures ordinarily used in the Construction
16 Industry to measure a safe work site, Polk Power Station
17 exceeds by far the industry standards. This was achieved
18 by all contractors working together under the safety
19 program established for the Project.

20
21 Q. How was the current projected cost for operations and
22 maintenance of the Polk Power Station Project developed?

23
24 A. In developing the projected operations and maintenance
25 costs for the Polk Power Station Project, we looked at the

1 various area/systems within the plant design and gathered
2 data to support a detailed estimate of those costs.
3

4 The information used in the development of the projected
5 costs consisted of information furnished by many vendors,
6 engineering and fabrication shops, and by visits to similar
7 facilities.
8

9 Tampa Electric has an agreement with Tennessee Eastman for
10 obtaining maintenance information and operator training at
11 its coal gasification plant located in Kingsport,
12 Tennessee.
13

14 An overall maintenance schedule was also developed which
15 included scheduled maintenance activities determined on
16 various site visits in addition to input from equipment
17 vendors and actual experience from various operating plants
18 such as Cool Water, Tennessee Eastman, and input from
19 Texaco, and Bechtel along with our engineering personnel.
20

21 Q. What is your projected 1997 O&M expense net of DOE funding?
22

23 A. The projected 1997 O&M expense net of DOE is \$2,669,000.
24

25 Q. How does Tampa Electric's current estimate for O&M compare

1 to EPRI TAG guidelines?

2
3 A. Tampa Electric has developed a detailed 1997 O&M cost
4 estimate for the first year of operation. When evaluated
5 against a comparable estimate based upon EPRI TAG
6 guidelines, the Tampa Electric estimate is about 8% less.
7 This comparison is made before taking credit for any DOE
8 O&M cost sharing.

9
10 Q. Describe the process Tampa Electric used to select the
11 operating staff for the Polk Power Station Project.

12
13 A. At the Polk Power Station, we established a work
14 environment using a multi-skilled, self-directed work team
15 approach. This non-traditional work environment is used by
16 many of the more successful organizations today. By using
17 this philosophy, we held staffing requirements to 72 people
18 for normal operations. The craft people selected were
19 expected to perform both operations and maintenance
20 functions. This approach allows for a greater utilization
21 of both time and skills of the employees. The design and
22 implementation of the staffing system used required
23 extensive participation and commitment by the Polk
24 Management Team as well as key members of the Human
25 Resources Department. Though the process was more lengthy

1 than other forms of selection techniques, the end result is
2 technically competent individuals that fit the team and
3 multi-skilled environment of the Polk Power Station.
4

5 Q. Is the Polk Power Station Project currently on schedule?
6

7 A. Yes, it is. We have met our schedule for all significant
8 project milestones to date.
9

10 If the start-up and check-out phase of Polk Unit One does
11 not identify any new technological or operational problems,
12 the project management team expects an on-schedule
13 commercial operation date of October 15, 1996.
14

15 Q. Please summarize your testimony.
16

17 A. The Polk Power Station Project represents a unique
18 technology at a new site to reliably meet the needs of
19 Tampa Electric's Customers. The DOE has provided funds and
20 monitored the project closely. We expect the project will
21 be completed on schedule, on budget, and will achieve the
22 technical results expected. These results demonstrate that
23 the project was managed aggressively, that the costs
24 incurred were reasonable and prudent and that the overall
25 project results will provide the expected benefits to our

1 Customers over the life of the Unit.

2

3 Q. Does that conclude your testimony?

4

5 A. Yes it does.

6

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TAMPA ELECTRIC COMPANY
DOCKET NO. 960409-EI
WITNESS: BLACK
EXHIBIT NO. ____ (CRB-1)

TAMPA ELECTRIC COMPANY

INDEX

Document No.	Document Title	Page
1-12	Interrogatories Filed in Docket No. 950379-EI and 960409-EI	1
13	Polk Site Maps	228
14	Polk IGCC Technology diagram	231
15	Texaco Gasification Process	233
16	Texaco Coal Gasification Brochure	245
17	Texaco Paper of Operating Data	263
18	Texaco Gasification of Sewage Sludges (System Capabilities)	281
19	Technology for Energy and the Environment	300
20	Awards by Texaco for Gasification Process & Cool Water Program	313
21	Use of the Ube Coal Gasification Slag	315
22	Paper on Texaco Gasification Process (EPRI)	330
23	News from Texaco	338
24	EPRI Coal Gasification Reports Available	341
25	Technical Papers Available from Texaco	346
26	Polk Project Cost Estimate Comparison	351
27	Summary of Significant Cost Control Actions	353

TAMPA ELECTRIC COMPANY
DOCKET NO. 960409-EI
WITNESS: BLACK
EXHIBIT NO. ____ (CRB-1)
DOCUMENT NO. 1-12
PAGE 1 OF 227

DOCUMENT NO. 1 - 12

INTERROGATORIES FILED
BY CHARLES R. BLACK
IN DOCKET NOS. 950379-EI AND 960409-EI

**TAMPA ELECTRIC COMPANY
DOCKET NO. 950379-EI
STAFF'S FIRST SET
INTERROGATORY NO. 1
SPONSOR: BLACK/HERNANDEZ
PAGE 1 OF 8**

1. At the time of the Need Determination for the Polk IGCC Unit, Tampa Electric estimated an installed cost of approximately \$389 million, net of the DOE grant. (See page 9 of Order No. PSC-92-0002-FOF-EI.) In response to a Staff data request in Docket 950379-EI, Tampa Electric now estimates an installed cost of approximately \$503 million. (See Item 5 of November 15 response from Gordon Gillette to Tim Devlin.)
 - a. Please provide a time-based flow chart by major construction activity showing the projected expenditures for the Polk IGCC Unit based on the original cost estimate of approximately \$389 million provided during the Need Determination proceedings. Please explain and show the effect of the DOE funding in this flow chart.
 - b. Please provide a time-based flow chart by major construction activity showing the actual and projected expenditures for the Polk IGCC Unit based on revised cost estimates at the time the decision was made to construct the unit as an integrated IGCC rather than as a separate advanced combustion turbine with a later addition of a heat recovery steam generator/coal gasifier. Please explain and show the effect of the DOE funding in this flow chart.
 - c. Please provide a time-based flow chart by major construction activity showing the actual and projected expenditures for the Polk IGCC Unit based on the current cost estimate of approximately \$503 million. Please explain and show the effect of the DOE funding in this flow chart.
- A.
 - a. Three estimates of the Polk Unit 1 IGCC costs are shown in the record for Tampa Electric's Determination of Need proceedings. The attached Table 1-1 (on page 4 of this response) shows the basis and origin of these estimates and the estimated cash flow streams. The original estimate of \$291.9 million in 1991 dollars (or \$372.6 million in 1996 dollars) was the basis for the \$62 million savings referenced on page 4 of the Prepared Direct Testimony of John B. Ramil submitted on September 5, 1991. An intermediate estimate of \$305.0 million (or \$389.5 million in 1996 dollars) was provided in the December 4, 1991 Deposition of John B. Ramil by the FPSC Staff. This estimate was apparently the basis for the \$389 million cost later referenced in Commission Order No. PSC-92-0002-FOF-EI on March 2, 1992.

This Order also references the estimate of \$319.9 million in 1991 dollars (or \$413 million in as-spent dollars through 1996) submitted on December 9, 1991 in the revisions to the Prepared Rebuttal Testimony of John B. Ramil originally filed on November 20, 1991. This estimate was the basis for the \$195 million system savings referred to on page 9 of Order No. PSC-92-0002-FOF-EI for constructing an IGCC unit compared to constructing a combined cycle unit and also shown in Document No. 1 of the Rebuttal Exhibit of John B. Ramil titled "Comparison of Unit Parameters and Customer Savings." The \$413 million installed cost estimate including AFUDC was also provided in the 1992 Tampa Electric Ten Year Site Plan (Table 10-1, Form 8A) filed April 1, 1992.

At the time of the Need Hearings (December 1991), detailed cash flow projections for the project had not been generated by major construction activity and the DOE Cooperative Agreement had not been signed. Therefore, a cash flow projection was not provided related to the \$413 million estimate. However, in response to this Interrogatory, the cash flow methodology inherent in John Ramil's Supplemental Testimony and Deposition Late Filed Exhibit No.4 has been used to provide a cash flow distribution shown in Table 1-2 for the December 9, 1991 Need Hearing estimates.

The \$195 million system savings referenced by the Commission in the Order and was based on the \$413 million estimate which contained the DOE funding and AFUDC but did not include the land and site development expense as part of the unit installed cost. For purposes of comparison, land and site development costs were considered approximately the same between alternative technologies that would be constructed at the same site and would not impact the economic analyses on a differential cumulative present worth revenue requirement (CPWRR) basis.

- b. At the time of the Need Hearings (December 1991), the most cost effective plan was to construct the unit as a phased construction Integrated Coal Gasification Combined Cycle (IGCC) plant with a commercial operation date of July 1, 1995 for the 7F advanced combustion turbine and the balance of the IGCC plant with commercial operation by July 1, 1996. This decision was the subject of John Ramil's Prepared Rebuttal Testimony in the Need Hearings.

TAMPA ELECTRIC COMPANY
DOCKET NO. 950379-EI
STAFF'S FIRST SET
INTERROGATORY NO. 1
SPONSOR: BLACK/HERNANDEZ
PAGE 3 OF 8
(Corrected 2/16/96)

In August 1993, an economic and system reliability analysis showed that the 7F advanced combustion turbine could be deferred from a commercial operation date of July 1995 to July 1996 while cost effectively maintaining system reliability. The deferral of the combustion turbine is shown in the 1994 Tampa Electric Ten Year Site Plan (Table III-1, Form 6) filed April 1, 1994. The deferral postponed revenue requirements that would have occurred in July 1995 as the first phase of the plant was placed in service. The revised cash flow and total project estimates are shown on Table 1-3.

- c. The installed cost estimate of approximately \$503 million was prepared by Bechtel in the fall of 1994 and based on a detailed engineering analysis. This estimate was based on contractual commitments to date, planning studies, plot plans, electric single line diagrams, instrument index, equipment indexes, and civil engineering design sketches issued up to July 1994. The \$503 million estimate was net of DOE and EPRI funding and included all known work associated with the project including land acquisition, site development, and AFUDC costs. At the time of this estimate, the DOE cooperative agreement had been signed and the cash call guidelines and procedures had been set. The approved DOE capital cost funding available at the time of this estimate was approximately \$110 million based on cost sharing formulas in the cooperative agreement and an additional \$20 million in funding for operating and maintenance expenses during the two-year demonstration period. The estimate has been allocated by year in accordance with the estimate detail provided by Bechtel and is shown in Table 1-4. Adjusting the \$503 million estimate to remove AFUDC and land acquisition and site development costs results in a \$385 million estimate for direct plant costs and puts this estimate on a comparable basis to the December 1991 Need Hearing estimate of \$372 million. This \$13 million increase represents a 3.5% variance to the December 1991 Need Hearing estimate as shown in Table 2-1, page 3 of 3 response to Interrogatory No. 2.

The most current estimate of approximately \$506 million reflects the decision by EPRI in 1995 to withdraw funding of \$3 million for the development of the IGCC simulator used for modeling of the IGCC process and for operations training of plant personnel. The time-based flow chart for the \$506 million estimate is shown in Table 1-5 (page 8) of this response. Adjusting the \$506 million estimate to remove AFUDC, land acquisition and site development costs, as discussed above, results in a current estimate of \$388 million. This \$16 million variance to the 1991 Need Hearing represents a 4.3% increase as shown in Table 2-1.

TABLE 1-1

**POLK UNIT ONE INSTALLED COST ESTIMATES
PROVIDED DURING THE DETERMINATION OF NEED HEARING**

	(1)	(2)	(3)
Unit Capacity (MW)	220	230	258.5
1991 \$ (\$000)	\$291,940	\$305,012	\$319,882
1991 \$ (\$/kW)	1,327	1,327	1,237
1996 \$ (\$000)	372,598	389,534	408,259
1996 \$ (\$/kW)	1,693	1,693	1,579
As Spent 96 \$ (000)			
1991	0	0	0
1992	4,026	4,209	4,524
1993	51,964	54,326	56,147
1994	209,418	218,937	228,206
1995	74,008	77,372	83,186
1996	0	0	0
Sub-Total	339,416	355,844	372,062
AFUDC	37,004	38,686	40,976
TOTAL	<u>\$376,420</u>	<u>\$393,530</u>	<u>\$413,038</u>

- (1) John B. Ramil Prepared Direct Testimony filed September 5, 1991
(2) Deposition of John B. Ramil by FPSC Staff filed December 4, 1991
(3) John B. Ramil Rebuttal Testimony Exhibit JBR-2 filed November 20, 1991 and Revised Rebuttal Testimony filed December 9, 1991.

NOTE: The cost of land and site development was excluded from these installed cost estimates.

TABLE 1-2
POLK PROJECT COST ESTIMATE
DETERMINATION OF NEED HEARING
DECEMBER 1991

YEAR	NET PROJECT COSTS ¹ (\$000)	DOE FUNDING (\$000)	<u>MAJOR CONSTRUCTION ACTIVITY</u>
1992	\$4,705	(\$1,216)	
1993	58,939	(15,091)	
Due to the nature of this estimate and the methodology used to develop it, yearly activities were not yet identified. Generic, historical construction curves were utilized to provide expected yearly expenditures for this estimate.			
1994	243,381	(61,335)	
1995	106,014	(22,358)	
1996	0	0	
TOTAL	<u>\$413,038²</u>	<u>(\$100,000)</u>	

¹ Project costs shown include AFUDC and are net of the DOE funding shown in Column 3. The cost for land and site development is excluded in this estimate.

² December 9, 1991 Fluor Daniel estimate provided in Table 1-1, page 4 of 8, of Interrogatory No. 1 response.

TABLE 1-3
POLK PROJECT COST ESTIMATE
BECHTEL ENGINEERING PRELIMINARY ESTIMATE
FALL 1993

YEAR	NET PROJECT COSTS ¹ (\$000)	DOE FUNDING (\$000)	MAJOR CONSTRUCTION ACTIVITY
1992	\$15,295	(\$3,741)	- Continued Polk Project permitting & certification activities. - Amended DOE Cooperative Agreement. - Selected A/E and completed Preliminary Engineering Package (PEP). - Developed business agreements for detailed engineering, consulting, and construction management services. - Developed RFPs for Air Separation unit (ASU), Syngas Cooler, and other major equipment. - Order issued for FPSC Need for Polk Power Station Unit No. 1.
1993	73,068	(15,110)	- Continue Polk Project permitting & certification activities. - Complete land acquisition activities. - Award contracts: detailed engineering & consulting services; Air Separation unit engineer, procure and construct; radiant & convective cooler purchases; Hot Gas Clean-up (HGCU) system design package; other long-lead plant equipment purchases. - Prepare bid packages for site reclamation and plant equipment. - Continue detailed engineering, procurement, and project management activities.
1994	108,630	(25,332)	- Complete Polk Power site certification. - Complete Environmental Impact Statements (EIS) for Environmental Protection Agency (EPA). - Complete U.S. Army Corps of Engineers 404 permit. - Award contracts: site development east of SR 37; sulfuric acid plant; brine concentration system equipment; coal handling system equipment; structural steel, piping, and other bulk materials; control, maintenance, and warehouse buildings; coal silos; miscellaneous plant equipment; railroad, site wells, and field erected tanks; underground piping and plant foundations. - Continue detailed engineering, procurement, and project management activities. - Bid balance of major construction contracts. - Begin delivery of bulk material and major equipment.
1995	233,188	(55,656)	- Ongoing construction contracts: railroad, site wells, coal silos, and field erected tanks; underground piping, plant foundations, and structural steel; site development and buildings. - Contractor mobilizations: sulfuric acid plant and ASU; power block contractor; gasification process contractor; HGCU and balance of plant contractors. - Delivery of balance of bulk materials and major equipment. - Continue detailed engineering, procurement, and project management activities. - Plant staff hiring and training.
1996	59,605	(11,307)	- Complete construction contracts. - Contract for final paving and landscaping. - Plant staff training. - Start-up of plant equipment, systems, and processes. - Initiate DOE demonstration period.
TOTAL	\$489,786	(\$111,146)	

¹ Project costs shown include AFUDC and are net of the DOE funding. The cost for land and site development is included in this estimate.

TABLE 1-4
POLK PROJECT COST ESTIMATE
BECHTEL ENGINEERING DEFINITIVE ESTIMATE
FALL 1994

YEAR	NET PROJECT COSTS ¹ (\$000)	DOE FUNDING (\$000)	MAJOR CONSTRUCTION ACTIVITY
1992	\$15,295	(\$3,741)	- Continued Polk Project permitting & certification activities. - Amended DOE Cooperative Agreement. - Selected A/E and completed Preliminary Engineering Package (PEP). - Developed business agreements for detailed engineering, consulting, and construction management services. - Developed RFPs for Air Separation unit (ASU), Syngas Cooler, and other major equipment.
1993	75,527	(11,809)	- Order issued for FPSC Need for Polk Power Station Unit No. 1. - Continued Polk Project permitting & certification activities. - Completed land acquisition activities. - Awarded contracts: detailed engineering & consulting services; Air Separation unit engineer, procure and construct; radiant & convective cooler purchases; Hot Gas Clean-up (HGPU) system design package; other long-lead plant equipment purchases. - Prepared bid packages for site reclamation and plant equipment. - Continued detailed engineering, procurement, and project management activities.
1994	98,994	(26,824)	- Complete Polk Power site certification. - Complete Environmental Impact Statements (EIS) for Environmental Protection Agency (EPA). - Complete U.S. Army Corps of Engineers 404 permit. - Award contracts: site development east of SR 37; sulfuric acid plant; brine concentration system equipment; coal handling system equipment; structural steel, piping, and other bulk materials; control, maintenance, and warehouse buildings; coal silos; miscellaneous plant equipment; railroad, site wells, and field erected tanks; underground piping and plant foundations. - Continue detailed engineering, procurement, and project management activities. - Bid balance of major construction contracts. - Begin delivery of bulk material and major equipment.
1995	223,911	(54,329)	- Ongoing construction contracts: railroad, site wells, coal silos, and field erected tanks; underground piping, plant foundations, and structural steel; site development and buildings. - Contractor mobilizations: sulfuric acid plant and ASU; power block contractor; gasification process contractor; HGPU and balance of plant contractors. - Delivery of balance of bulk materials and major equipment. - Continue detailed engineering, procurement, and project management activities. - Plant staff hiring and training.
1996	89,590	(13,550)	- Completion of construction contracts. - Contract for final paving and landscaping. - Plant staff training. - Start-up of plant equipment, systems, and processes. - Initiate DOE demonstration period.
TOTAL	\$503,317	(\$110,253)	

¹ Project costs shown include AFUDC and are net of the DOE funding. The cost for land and site development is included in this estimate.

TABLE 1-5
POLK PROJECT COST ESTIMATE
REVISED BECHTEL ENGINEERING ESTIMATE
FALL 1995

YEAR	NET PROJECT COSTS ¹ (\$000)	DOE FUNDING (\$000)	MAJOR CONSTRUCTION ACTIVITY
1992	\$15,295	(\$3,741)	- Continued Polk Project permitting & certification activities. - Amended DOE Cooperative Agreement. - Selected A/E and completed Preliminary Engineering Package (PEP). - Developed of business agreements for detailed engineering, consulting, and construction management services. - Developed RFPs for Air Separation unit (ASU), Syngas Cooler, and other major equipment. - Order issued for FPSC Need for Polk Power Station Unit No. 1.
1993	75,527	(11,809)	- Continued Polk Project permitting & certification activities. - Completed land acquisition activities. - Award contracts: detailed engineering & consulting services; Air Separation unit engineer, procure and construct; radiant & convective cooler purchases; Hot Gas Clean-up (HGCU) system design package; other long-lead plant equipment purchases. - Prepared bid packages for site reclamation and plant equipment. - Continued detailed engineering, procurement, and project management activities.
1994	102,273	(27,628)	- Completed Polk Power site certification. - Completed Environmental Impact Statements (EIS) for Environmental Protection Agency (EPA). - Completed U.S. Army Corps of Engineers 404 permit. - Awarded contracts: site development east of SR 37; sulfuric acid plant; brine concentration system equipment; coal handling system equipment; structural steel, piping, and other bulk materials; control, maintenance, and warehouse buildings; coal silos; miscellaneous plant equipment; railroad, site wells, and field erected tanks; underground piping and plant foundations. - Continued detailed engineering, procurement, and project management activities. - Bid balance of major construction contracts. - Began delivery of bulk material and major equipment.
1995	215,380	(52,485)	- Ongoing construction contracts: railroad, site wells, coal silos, and field erected tanks; underground piping, plant foundations, and structural steel; site development and buildings. - Contractor mobilizations: sulfuric acid plant and ASU; power block contractor; gasification process contractor; HGCU and balance of plant contractors. - Delivery of balance of bulk materials and major equipment. - Continue detailed engineering, procurement, and project management activities. - Plant staff hiring and training.
1996	97,690	(19,732)	- Completion of construction contracts. - Contract for final paving and landscaping. - Plant staff training. - Start-up of plant equipment, systems, and processes. - Initiate DOE demonstration period.
TOTAL	\$506,165	(\$115,395)	

¹ Project costs shown include AFUDC and are net of the DOE funding. The cost for land and site development is included in this estimate.

**TAMPA ELECTRIC COMPANY
DOCKET NO. 950379-EI
STAFF'S FIRST SET
INTERROGATORY NO. 2
SPONSOR: BLACK\HERNANDEZ
PAGE 1 OF 3**

2. Please provide a full and complete reconciliation and justification of the differences between the magnitude and timing of costs shown in response to Interrogatory No. 1.a. through 1.c. above.

- A. As depicted on the attached Table 2-1, based on a consistent comparison which excludes the estimated land acquisition and site development and AFUDC expense, the comparative costs of Polk Unit No. 1 have remained relatively unchanged (4.3% above the December 9, 1991 Need Hearing estimate). The Need Hearing estimate was completed before any project specific engineering or design work had been completed, as was the case with all the estimates examined as alternatives. It should also be noted that the design of this unit combines the innovative integration of proven technologies with a developmental hot gas clean-up process (HGPU) that offers potentially lower unit heat rates and therefore lower operating costs. At the time of the Need Hearing, only one IGCC unit had been built in the United States, and no unit exactly like the Polk unit has ever been built. The advancement of the integration and technology of the unit is the reason DOE had provided funding for the project, and the relative newness of the design makes the projection of costs more difficult.

The initial estimate of \$413 million (Table 1-2, Interrogatory No. 1) was developed using, primarily, capacity-factored and equipment-factored estimating techniques. Capacity-factored estimating is based on multiplying the cost of a similar unit for which the direct construction costs are known by the ratio of the new unit's capacity to that of the similar unit. Capacity ratios are adjusted by an exponent chosen on the basis of the unit type. Equipment-factored estimating is based on the cost and specifications of each major equipment item (vessels, compressors, turbines, exchangers, etc.). Costs for bulk materials and field labor man-hour requirements are factored, based on appropriate equipment parameters (duty, size, weight, metallurgy, temperature, pressure, etc.), to determine the total direct construction cost. Such estimates have obvious limitations, but they are often used to produce relative "Order of Magnitude" accuracy comparisons. Expected accuracy ranges of total project cost estimates tend to narrow as more information becomes available throughout the life of any project.

The fall 1993 preliminary estimate (Table 1-3, Interrogatory No. 1) concentrated on the scope and pricing of major equipment. Budget quotes were obtained from prospective bidders to establish equipment costs. Bulk materials and construction labor costs were factored as a percentage of major equipment dollars based on historical data. These more design-specific estimating processes typically result in improved levels of accuracy.

The fall 1994 (Table 1-4, Interrogatory No. 1) estimate was much more detailed than previous estimates and was based on planning studies, piping and instrumentation diagrams, plot plans, electrical single line diagrams, instrument index, equipment index, and civil design drawings and sketches. Equipment pricing was based on commitments and budget quotes. Large bore piping, electrical, instrumentation, concrete, structural steel, buildings, and earthwork estimates were based on quantity take-offs and historical pricing data. Construction labor man-hours were generated from take-off quantities and priced out using 1994 labor rates and historical production rates.

The fall 1995 estimate (Table 1-5, Interrogatory No. 1) was more detailed and relied heavily on actual contract commitment data and an engineering estimate of work not yet under contract. At the time of this update, the project was approximately 86% committed. The acceptable industry standard of this type of reforecast would be +10% and -5%.

A primary objective of the Polk project management team has always been to manage capital costs to their lowest possible levels. Many scope modifications have taken place as the project has evolved. A few of the significant changes implemented to achieve a more cost effective project since the early stages of this project include, but are not limited to the following:

- reduction of on-site coal storage capabilities by utilizing existing facilities;
- replacement of original sulfur recovery and tail gas treating systems with a more cost effective sulfuric acid plant;
- deletion of piling requirements for all major structures; and
- reduction of overall site plot plans to reduce bulk material requirements.

The capital costs have essentially remained level from the pre-design stage through construction when comparable costs are examined. The 4.3% variance from 1991 Need Hearing estimates to the 1995 definitive project reforecast is a significant achievement for the first-time design and installation of a new technology such as an IGCC power plant. If the start-up and check-out phase of the project does not identify any new technological or operational problems, the project management team expects the comparable capital costs to remain within 5% of the December 9, 1991 Need Hearing estimates.

TABLE 2-1

POLK PROJECT COST ESTIMATE COMPARISONS
(\$000)

INTERROGATORY REFERENCE:	(1a)	(1b)	(1c)	(1c)
	Need Hearing 12/91 Estimate	Fall 1993 Estimate	Fall 1994 Estimate	Fall 1995 Estimate
<u>Plant Components</u>				
Plant	\$472,062	\$488,016	\$495,523	\$503,331
DOE Funding	(100,000)	(111,146)	(110,253)	(115,395)
Subtotal without AFUDC & Land	372,062	376,870	385,270	387,936
% Variance from 12/91 Estimate		1.3%	3.5%	4.3%
Land Acquisition & Site Development	0	56,353	64,535	65,835
AFUDC	40,976	56,563	53,513	52,394
TOTAL PROJECT ESTIMATE:	<u>\$413,038</u>	<u>\$489,786</u>	<u>\$503,318</u>	<u>\$506,165</u>

Key Estimate Clarifications

1. The 12/91 Need Hearing estimate (Column 1a) excluded Land Acquisition & Site Development costs in installed cost.
2. The Fall 1993, Fall 1994, and Fall 1995 estimates included Land Acquisition & Site Development costs.
3. Through time, as estimates were developed with more engineering data, component costs were captured more accurately and consistently utilizing the project work break-down structure developed during the preliminary engineering stage of the project in 1992.
4. The Fall 1994 and Fall 1995 estimates (Columns 1c) were prepared as a budget estimates using flow sheets, layout, and equipment details.

**TAMPA ELECTRIC COMPANY
DOCKET NO. 950379-EI
STAFF'S FIRST SET
INTERROGATORY NO. 4
SPONSOR: BLACK
PAGE 1 OF 40**

4. Please provide a copy of the agreement between Tampa Electric and the DOE for funding for the Polk IGCC Unit. Please provide the date on which the contract became effective. Please describe the conditions under which funding under this agreement could be terminated.
- A. The effective date of the attached (Document 4-1) original Cooperative Agreement No. DE-FC21-9127363 between the U.S. Department of Energy and Clean Power Cogeneration, Incorporated was March 18, 1991. This agreement was modified to change the participant from Clean Power Cogeneration, Incorporated to Tampa Electric Company on March 5, 1992 (attached Document 4-2). The conditions under which funding under this agreement could be terminated are described in Article XX beginning on page 15 of Document 4-1 (page 21 of this Interrogatory).

TAMPA ELECTRIC COMPANY
DOCKET NO. 950379-EI
STAFF'S FIRST SET
INTERROGATORY NO. 4
SPONSOR: BLACK
PAGE 2 OF 40

DOCUMENT 4-1
COPY OF THE COOPERATIVE AGREEMENT
BETWEEN THE
U. S. DEPARTMENT OF ENERGY
AND
CLEAN POWER COGENERATION, INCORPORATED
March 18, 1991

COPY 1 OF 25

COOPERATIVE AGREEMENT NO. DE-FC21-9127363

and

REPAYMENT AGREEMENT NO. DE-FR21-91MC28149.000

CPC AIR-BLOWN INTEGRATED GASIFICATION COMBINED CYCLE PROJECT

Between

THE U.S. DEPARTMENT OF ENERGY

and

CLEAN POWER COGENERATION, INCORPORATED

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CLEAN POWER COGENERATION, INC.
AIR-BLOWN INTEGRATED GASIFICATION COMBINED CYCLE PROJECT

TABLE OF CONTENTS

	<u>Page</u>
TABLE OF CONTENTS	i
LISTING OF SCHEDULE ARTICLES:	
ARTICLE I — STATEMENT OF JOINT OBJECTIVES	1
ARTICLE II — DEFINITIONS	1
ARTICLE III — SUBSTANTIAL INVOLVEMENT BETWEEN DOE AND THE PARTICIPANT	4
ARTICLE IV — DESIGNATION OF THE DOE CONTRACTING OFFICER'S REPRESENTATIVES	5
ARTICLE V — KEY PERSONNEL	5
ARTICLE VI — PROJECT SITE AND ACCESS	6
ARTICLE VII — AGREEMENT TERM, PROJECT PHASES AND ESTIMATED PROJECT COSTS	6
ARTICLE VIII — PROJECT DECISION MAKING	7
ARTICLE IX — PROJECT DEFINITION	9
ARTICLE X — DOE FINANCIAL SUPPORT	9
ARTICLE XI — ALLOWABLE PRE-AWARD COSTS	11
ARTICLE XII — BUDGET ADJUSTMENTS	11
ARTICLE XIII — PAYMENT	12
ARTICLE XIV — RIGHTS IN INTELLECTUAL PROPERTY	13
ARTICLE XV — REPORTING REQUIREMENTS	13
ARTICLE XVI — PROCUREMENT	13
ARTICLE XVII — INSURANCE AND INDEMNITY	14
ARTICLE XVIII — BONDING FOR CONSTRUCTION	15
ARTICLE XIX — PROPERTY MANAGEMENT AND DISPOSITION	15
ARTICLE XX — TERMINATION	15

CLEAN POWER COGENERATION, INC.
 AIR-BLOWN INTEGRATED GASIFICATION COMBINED CYCLE PROJECT

TABLE OF CONTENTS
 (Continued)

	<u>Page</u>
ARTICLE XXI — DISPUTES AND APPEALS	16
ARTICLE XXII — RECORDS RETENTION, ACCESS, AND DISCLOSURE	17
ARTICLE XXIII — PUBLIC INFORMATION RELEASE	18
ARTICLE XXIV — LEGAL NOTICE/DISCLAIMER	18
ARTICLE XXV — COMMERCIALIZATION	18
ARTICLE XXVI — OPTION TO CONTINUE	19
ARTICLE XXVII — INTEREST	19
ARTICLE XXVIII — LIMITATION ON PAYMENTS TO INFLUENCE CERTAIN FEDERAL TRANSACTIONS	19
ARTICLE XXIX — PERFORMANCE GUARANTEE	19
ARTICLE XXX — REPAYMENT	20
ARTICLE XXXI — SPECIAL SURVEILLANCE SUBCONTRACTS	20
ARTICLE XXXII — ADDITIONAL PARTICIPANT RESPONSIBILITY	21
ARTICLE XXXIII — SEVERABILITY	21

LISTING OF ATTACHMENTS:

- ATTACHMENT A — Statement of Work
- APPENDIX 1 — Guideline for Preparation of Project Management Plan
- ATTACHMENT B — Intellectual Property Provisions
- APPENDIX 1 — Non-Disclosure Agreement
- ATTACHMENT C — Reporting Requirements
- ATTACHMENT D — Contract Clauses
- ATTACHMENT E — Commercialization and Performance Arrangements

SCHEDULE OF ARTICLES

ARTICLE I — STATEMENT OF JOINT OBJECTIVES

(A) Primary Objective

The primary objective of this Cooperative Agreement is to conduct a cost-shared project that will demonstrate air blown fixed-bed integrated gasification combined cycle (IGCC) technology. The parties anticipate that, if the demonstration project is successful, the air blown fixed-bed IGCC technology could become commercialized during the 1990's and will be capable of (1) achieving significant reductions in the emissions of sulfur dioxide and the oxides of nitrogen from existing facilities to minimize environmental impacts such as transboundary and interstate pollution, and (2) providing for future energy needs in an environmentally acceptable manner.

(B) Technical Objectives of the Demonstration Project

As specified in the Statement of Work, the Participant will demonstrate air blown fixed-bed IGCC technology. Such a demonstration is expected to show that an air-blown IGCC can achieve significant reductions of SO₂ and NO_x emissions when compared to existing and future coal-burning power plants. The integrated performance to be demonstrated will include all major subsystems in the IGCC system entailing coal feeding; a pressurized, air-blown, fixed-bed gasifier capable of utilizing caking coal; a hot gas conditioning system for removing sulfur compounds, particulates, and other contaminants as necessary to meet environmental and combustion turbine fuel requirements; a conventional combustion turbine appropriately modified to utilize low-Btu coal gas as fuel; a system such as a briquetting system for improved coal feed performance; the heat recovery steam generation system appropriately modified to accept a NO_x reduction system such as a selective catalytic reduction process; the steam cycle; all control systems; and the balance of plant.

(C) Legal Authority for This Cooperative Agreement

The expenditure of DOE funds under this Cooperative Agreement is subject to the requirements of Public Law 100-446. Except as otherwise expressly provided in Public Law 100-446 or by the terms of this Cooperative Agreement, the parties shall comply with the applicable provisions of Subparts A, B, and C of the DOE Financial Assistance Rules, 10 CFR Part 600.

ARTICLE II — DEFINITIONS

- (A) "Budget" means the financial expenditure plan for carrying out the project. The budget includes the cost sharing the Participant is required to provide and, for Phase III, shall include the fixed and variable allowable costs of operating the demonstration facility.

- (B) "Budget Period" means the interval of time, specified in Article VII of this Cooperative Agreement, into which the project is divided for budgeting and funding purposes.
- (C) "Continuation Award" means an award for a succeeding or subsequent budget period after the first budget period of this Cooperative Agreement.
- (D) "Contracting Officer" means the DOE official authorized to execute awards and amendments thereto on behalf of DOE and who is responsible for the business management and non-program matters relating to this Cooperative Agreement.
- (E) "Contracting Officer's Representative (COR)" means the DOE-authorized representative for all technical matters pertaining to the Cooperative Agreement.
- (F) "Cooperative Agreement" means this agreement between the DOE and the Participant, DOE Instrument Number DE-FC21-91MC27363.000, and any subsequent amendments.
- (G) "Cost-Sharing" means the portion of the allowable direct and indirect project costs required to be borne by the Participant.
- (H) "DOE" means the United States Department of Energy and any successor department or agency.
- (I) "Government" means the Government of the United States, including DOE.
- (J) "NEPA" means the National Environmental Policy Act of 1969, 42 U.S.C. § 4321 et seq.
- (K) "Participant" means Clean Power Cogeneration Limited Partnership and its successors and assigns. Clean Power Cogeneration Limited Partnership is a limited partnership consisting of Clean Power Cogeneration, Inc. (CPC), the general partner; CRSS Power, Inc., a limited partner; and TFS Clean Coal, Inc., a limited partner.
- (L) "IGCC Technology" means all of the patented and/or unpatented technical data and know-how required to design, procure, construct, and operate an integrated coal gasification combined cycle system comprised of the following basic elements and process: A pressurized, air-blown, fixed-bed gasifier, capable of utilizing caking coal which is gasified in the presence of steam and air to produce a hot product gas mixture composed substantially of hydrogen and carbon monoxide; a hot gas conditioning system for removing sulfur compounds, particulates, and other contaminants as necessary to meet environmental and turbine fuel requirements; systems or mechanical devices for improved coal feed performance; a combined cycle power generation system wherein the cleaned product gas is combusted in a combustion turbine generator to make electrical power and wherein steam, produced from a heat recovery steam generator in the turbine exhaust, is used in part to feed a steam turbine generator to generate a second source of electrical power; a process integrated within the heat recovery steam generator or the combustion turbine for

NO control: and the control system and algorithms necessary to integrate and control the overall system as required by the operator, as demonstrated under this Cooperative Agreement including any improvements or modification embodied during commercialization by/or through the Participant which are incorporated into the system.

- (M) "Prior Approval" means documentation signed by a DOE Contracting Officer evidencing consent to the incurrence of a specific cost before it is incurred. The procedures for requesting prior approval are set forth in 10 CFR § 600.114(e).
- (N) "Project" means the set of activities described in Attachment A, Statement of Work, that the Participant is required to perform during Phases I, II, and III of this Cooperative Agreement.
- (O) "Program Income" means the gross income earned directly from any demonstration project activity supported with DOE funds during Phases I, II, and III. Such income includes fees for services; fees or rental income for the use of real or personal property acquired with DOE funds; and income from the sale of fuel, by-products, or energy generated by the demonstration project. Such income does not include interest on DOE funds; rebates, credits, discounts, refunds, etc., and any interest earned on any of the foregoing; or income from royalties and license fees.
- (P) "Public Law 100-446" means Title II of "an Act making appropriations for the Department of the Interior and related agencies for the fiscal year ending September 30, 1989, and for other purposes," specifically the provisions under the Department of Energy headings entitled, "Clean Coal Technology" (102 Stat. 1810-1811) and "Administrative Provisions, Department of Energy" (102 Stat. 1813-1814).
- (Q) "Repayment Agreement" means the agreement made by the Participant in DOE Instrument Number DE-FR21-91MC28149.000 in January 1991, to repay the DOE share of costs paid under this Cooperative Agreement.
- (R) "Total Approved Budget" means the amount of costs authorized to be incurred during each budget period, as shown on the Notice of Financial Assistance Award, by the Participant and any of its contractors. The total approved budget consists of DOE funds for allowable direct and indirect costs and the Participant's required cost sharing, and shall include the fair use value of in-kind contributions that will be made to carry out the project.
- (S) "United States" means the United States of America and its 50 states, the District of Columbia, the Commonwealth of Puerto Rico, and any possession or trust territory of the United States.
- (T) "Facility" means the nominal 120 MWe power plant using IGCC technology that is to be located at the Arvah B. Hopkins Power Station, located outside Tallahassee, Florida.

ARTICLE III — SUBSTANTIAL INVOLVEMENT BETWEEN DOE AND THE PARTICIPANT

There will be substantial involvement between DOE and the Participant in the management and execution of the project as defined in the following paragraphs:

- (A) Participant Role.
- (B) DOE Role.
- (C) No Government Obligation to Third Parties.
- (D) Participant's Project Management Structure/Procedures.

(A) Participant Role

The Participant shall be responsible for all aspects of project performance as set forth in the Cooperative Agreement, including all attachments. As stated in the Statement of Work, Attachment A, all services, personnel, facilities, equipment, materials, and supplies shall be furnished by the Participant, unless otherwise specified under this Cooperative Agreement.

The Participant shall designate a Project Manager who shall serve as its authorized representative for the technical and administrative elements of all work to be performed under this Cooperative Agreement. The Project Manager shall be the single authorized point of contact for all communications between the Participant and DOE.

(B) DOE Role

DOE shall monitor the Participant's progress in performing the project, and shall, as indicated in this paragraph and in Article VIII, have a substantial role in project decision making. DOE also shall approve or disapprove all actions for which, by the terms of this Cooperative Agreement, the Participant is required to obtain DOE's approval.

(C) No Government Obligation to Third Parties

In connection with the performance of the Project, the Government shall have no obligation or responsibility to any contractor, subcontractor, or other person who is not a party to this Cooperative Agreement. The foregoing limitation shall apply notwithstanding the Contracting Officer's prior approval or consent of any contract awarded by the Participant. The Participant shall be responsible, without recourse to DOE, for the resolution and satisfaction of all pre-award protests, contract administration issues, and contract disputes arising out of acquisitions related to the Project.

(D) Participant's Project Management Structure/Procedures

The Participant shall manage the project in accordance with the Project Management Plan which shall be submitted to DOE for approval. The approved Project Management Plan provides all necessary details concerning project management structure and procedures. Further, the Participant reserves for itself the right to modify the plant's design

and operating performance to improve efficiency to the extent that those changes do not substantially alter the objectives of the Statement of Work.

ARTICLE IV — DESIGNATION OF THE DOE CONTRACTING OFFICER'S REPRESENTATIVES

Contract Specialist: Alexis Puher
U.S. Department of Energy
Morgantown Energy Technology Center
P.O. Box 880
Morgantown, WV 26507-0880

COR: Dale Schmidt
U.S. Department of Energy
Morgantown Energy Technology Center
P.O. Box 880
Morgantown, WV 26507-0880

Patent Counsel: Irving Barrack
U.S. Department of Energy
Oak Ridge Operations Office
P.O. Box E
Oak Ridge, TN 37831

The DOE Contracting Officer is the only Government representative authorized to accept the reports and other deliverables the Participant is required to provide under this Cooperative Agreement. The review and approval of such reports and other deliverables may be delegated to the Contracting Officer's authorized representatives.

The DOE Contracting Officer shall designate a COR who shall have the authority to issue written Technical Advice which suggests redirecting the project work (e.g., by changing the emphasis among different tasks), or pursuing specific lines of inquiry likely to assist in accomplishing the Statement of Work. The COR shall have the authority to approve or disapprove those technical reports, plans, and other technical information the Participant is required to submit to DOE for approval. The COR is not authorized to issue and the Participant is not required to follow any Technical Advice which constitutes work which is not within the scope of the Statement of Work; which in any manner causes an increase or decrease in the total estimated cost or in the time required for performance of the project; which has the effect of changing any of the terms or conditions of the Cooperative Agreement; or which interferes with the Participant's right to perform the project in accordance with the terms and conditions of this Cooperative Agreement.

ARTICLE V — KEY PERSONNEL

The personnel specified in this clause are considered to be essential to the project. Before permitting the Project Manager to be absent for more than 3 months and before diverting any key person to other work, the Participant shall notify the Contracting Officer reasonably in advance and shall submit

justification (including proposed substitutions) in sufficient detail to permit evaluation of the impact on the project. No key person may be substituted without the Contracting Officer's approval, which approval shall not be unreasonably withheld. Such approval shall be obtained in advance of the substitution, except that the Contracting Officer may ratify a substitution which, because of exigent circumstances, was made before the Participant could request and/or obtain the Contracting Officer's approval.

<u>Name</u>	<u>Title</u>
1. J. Charles Hester	Project Manager Clean Power Cogeneration, Inc.
2. Donald E. Pless	Associate Project Manager Clean Power Cogeneration, Inc.
3. XXXXXXXXXXXX	Contract Manager

ARTICLE VI — PROJECT SITE AND ACCESS

The project shall be performed principally at the following site: City of Tallahassee's Arvah B. Hopkins Power Station, Tallahassee, Florida. At the request of the DOE Contracting Officer or the COR, the Participant shall provide Government officials and interested members of the public as determined by DOE with access to the project site to observe project operations at reasonable times and with reasonable limitations on the numbers of people during each visit except where public access must be limited due to valid safety or security concerns, under procedures to be mutually agreed upon between the Participant and DOE.

ARTICLE VII — AGREEMENT TERM, PROJECT PHASES AND ESTIMATED PROJECT COSTS

(A) Term of Agreement

The maximum term of this Cooperative Agreement shall be from the execution hereof through the completion of Phase III activities (unless sooner terminated).

(B) Project Phases

The project period of this Cooperative Agreement is divided into three project phases and three budget periods over a period of 60 months as follows:

Phase I — Design and Permitting (33 months).
Phase II — Procurement, Construction, and Start-Up (24 months).
Phase III — Operation and Data Collection (24 months).

Phases I and II overlap 21 months.

(C) Project Budget Periods

The project will consist of three (3) sequential budget periods as follows:

Budget Period 1 — 18 months
 Budget Period 2 — 18 months
 Budget Period 3 — 24 months

(D) Total Estimated Project Costs

DOE and the Participant shall share in allowable direct and indirect project costs in the percentages up to the amounts shown below:

TOTAL ESTIMATED PROJECT COST \$241,458,000

Pre-Award

DOE Share*	\$ 900,000	50.00%
Participant Share	\$ 900,000	50.00%

Phase I

DOE Share	\$ 8,050,000	50.00%
Participant Share	\$ 8,050,000	50.00%

Phase II

DOE Share	\$ 91,679,000	50.00%
Participant Share	\$ 91,679,000	50.00%

Phase III

DOE Share	\$ 20,100,000	50.00%
Participant Share	\$ 20,100,000	50.00%

Total

DOE Share	\$120,729,000	50.00%
Participant Share	\$120,729,000	50.00%

* Actual allowable incurred costs which shall be reimbursed as provided in Article XI of this Cooperative Agreement.

ARTICLE VIII — PROJECT DECISION MAKING

(A) Project Evaluation

Shortly after the beginning of each budget period except for the last one, the Participant shall submit a Project Evaluation Plan (Plan) for DOE review and approval. The Plan must identify and describe the criteria by which the technical and economic feasibility of the project,

based on the Participant's accomplishments during the budget period, are to be evaluated.

The DOE-approved Plan shall be used by the Participant to prepare a Project Evaluation Report which shall be submitted no later than 60 days before the end of the budget period. DOE shall use the approved Plan in evaluating the Participant's Evaluation Report and in deciding whether any accompanying continuation application will be approved.

(B) Continuation Applications

If the Participant wishes to continue the Project beyond the current budget period, the Participant shall submit, no later than 60 days before the end of the current budget period, a Continuation Application which contains the following:

- (1) The Project Evaluation Report which shall describe in detail the status of the project and the technical progress made during the budget period.
- (2) A detailed description of the Participant's plans for conducting the project during the next budget period.
- (3) A detailed budget by project phase for the next budget period, including the proposed value of each in-kind contribution and an estimate of unobligated balances [see Article XII (A)].

(C) Approval/Disapproval of Continuation Applications

DOE shall approve or disapprove a timely Continuation Application no later than 30 days before the expiration of the current budget period. DOE will approve the Continuation Application provided the criteria in the approved Project Evaluation Plan are met and appropriated funds are available for the Project. In determining whether the criteria have been met, DOE will consider the Participant's Project Evaluation Report and other related information. DOE shall disapprove a Continuation Application if appropriated funds are unavailable or insufficient.

(D) Limitation of Cost Liability

If the Participant does not submit a Continuation Application (i.e., withdraws from the project) or if DOE does not approve a continuation application, the liability of DOE shall be limited to its share of allowable costs incurred during the current or any previous budget period.

The Participant shall incur no new obligations, after the effective date of termination of the Cooperative Agreement and shall cancel as many outstanding obligations as possible. Notwithstanding anything to the contrary in the first sentence of this Article VII (D), DOE shall reimburse the Participant for the DOE share of noncancellable obligations properly incurred prior to the effective date of the termination.

ARTICLE IX — PROJECT DEFINITION

Before the end of the first budget period, the Participant shall complete the project definition activities identified in the Statement of Work as appropriate. The Project Evaluation Report for this first budget period shall contain: an updated Project Management Plan; the technology, schedule, and cost baselines for all future project work, by phase, to be performed during each subsequent budget period; and the environmental information volume and such other information as may be requested from time to time by DOE to satisfy its obligations under NEPA. Before approval of the first Continuation Application, the Participant shall deliver to DOE the signed commitments/agreements for any financing required to meet the Participant's total cost-sharing obligation under this Cooperative Agreement.

ARTICLE X — DOE FINANCIAL SUPPORT

(A) DOE Obligation

The maximum DOE obligation to the Participant is the amount identified in Block 16.b(3) of the Notice of Financial Assistance Award. DOE shall not be obligated to make any additional, supplemental, continuation, renewal, or other award for the same or any other purpose.

(B) Project Costs Not Allowed for Cost-Sharing Purposes

- (1) DOE shall not accept valuation for property sold, transferred, exchanged, or manipulated in any way to acquire a new basis for depreciation purposes or to establish a rental value in circumstances which would amount to a transaction undertaken solely for this Cooperative Agreement.
- (2) Revenues or royalties from prospective operation of the project after the end of the Cooperative Agreement or proceeds from the prospective sale of the assets of the project or revenues or royalties from replication of the technology in future projects or plants will not be considered cost sharing.
- (3) Fully depreciated property will not receive any cost-sharing value unless it has been in continuous use by the Participant during the entire calendar year 1988 [see Article X(C)].
- (4) Existing facilities, equipment, and supplies, or previously expended research or development funds are not cost sharing for the purposes of this Cooperative Agreement, except as amortized, depreciated, or expensed in normal business practice [see Article X(C)]. Contributions in the form of foregone revenues or replacement power costs are not considered as cost sharing.
- (5) Patents, proprietary data, or prior work will not be valued in determining the Participant's cost participation in the project.
- (6) The Participant may not charge allowable costs, which are absorbed into its share of cost participation, to the Government under other

contracts, agreements, or grants. Additionally, other appropriated Federal funds are not cost sharing for the purposes of this Cooperative Agreement except as provided in Public Law 100-446.

- (7) The Participant cannot consider foregone fee or profit for cost-share purposes. The Government will not pay fee or profit to the Participant under this Cooperative Agreement.
- (8) Except as defined below in Article X (C) (7), the Government will not pay costs for fuel and other variable operating expenses when the turbine is being fired solely on natural gas.
- (9) Under current DOE policy, Facilities Capital Cost of Money (FCCOM) shall be an unallowable cost on all real property or equipment acquired or on any facilities constructed by the Participant in connection with the performance of this project. If during the term of this Cooperative Agreement, however, DOE's policy should change as a result of either DOE or congressional action, then, subject to the availability of funds, and the fourth proviso of 42 U.S.C. 5903d, the allowability of FCCOM expense under this Cooperative Agreement would be determined in accordance with any such new DOE policy.

(C) Project Costs Allowable for Cost-Sharing Purposes

DOE shall share in allowable project costs in the percentages indicated in Article VII. The allowability of direct and indirect costs incurred in the performance of the project shall be determined in accordance with the cost principles set forth in 48 CFR 31.2 (Federal Acquisition Regulations) as modified by 48 CFR 931.2 (DOE Acquisition Regulations) [refer to list in 10 CFR § 600.103(b)] and the following:

- (1) For fully depreciated property contributed to the project and in continuous use during the entire calendar year 1988, a fair use value for the life of the project will be assigned by DOE. The fair use value will be the annual average depreciation used by the Participant as permitted under statute or IRS regulations under which it was depreciated.
- (2) The value that will be allowed for contributions of currently depreciating property and which are of relevance to the project is the depreciation schedule being used and allowed under statute or IRS regulations for the property. This depreciation will be limited in its cost-share value to the depreciation claimed during the life of the demonstration project.
- (3) Contributed land will be valued at its fair rental value for the period of the demonstration.
- (4) Contributed land, equipment, and facilities will be counted as cost sharing only for the periods during which they are brought into use for this project. For example, that portion of a facility used for housing the design team may be credited as a cost share during Phase I, but contributed equipment incorporated in the construction

may be credited as a cost share only during those portions of Phases II and III when used. Property owned by one of the project team members and made available to the project will be valued in agreement with the principles described above.

- (5) Value for contributed equipment and facilities will be assigned only to the extent that the facility or equipment is project related.
- (6) The cost of disposal of the facility and equipment is an allowable cost if proposed and if accomplished prior to the end of the Cooperative Agreement.
- (7) Costs incurred during periods of operation of the facility on coal as the primary fuel and during periods when the Participant is making reasonable and prudent efforts to prepare the facility for, or return the facility to, operation on coal as the primary fuel, including but not limited to periods of turbine start-up or shutdown on natural gas, routine equipment maintenance/repair or modification of equipment required to execute the statement of work, coal supply interruptions, supplemental or back-up firing on natural gas or oil when coal-derived fuel is not of sufficient quality or quantity for reliable or environmentally acceptable operation, and other similar periods as may be approved by the Contracting Officer.

(D) Program Income

Notwithstanding 10 CFR § 600.113, program income may be used by Participant for any purpose.

ARTICLE XI — ALLOWABLE PRE-AWARD COSTS

The Participant shall be entitled to reimbursement of a portion of certain pre-award costs it incurred after selection up to the amount set forth in Article XII (C) provided such costs are related to (1) the preparation of material requested by DOE and identified as required for negotiations, or (2) the preparation and submission of environmental data requested by the DOE to complete NEPA requirements for the project.

ARTICLE XII — BUDGET ADJUSTMENTS

(A) Unobligated Balances

As used in this paragraph, "unobligated balance" means the portion of DOE funds that has not been obligated by the Participant, and is determined by subtracting the DOE share of the cumulative costs incurred or obligated from the amount of DOE funds authorized for expenditure. When the Participant has unobligated balances of funds remaining at the end of any budget period except for the last one, such funds may be used in the subsequent budget period and shall be specified and included in the total approved budget shown in an amended Notice of Financial Assistance Award. Whenever it becomes apparent during the penultimate budget period, that the amount of DOE funding authorized is expected to exceed the Participant's needs by more than 5 percent of DOE's share of total allowable

costs, the Participant must notify DOE. DOE may reduce the award by an amount which does not exceed the total amount of excess funds.

(B) Budget Revisions

The Participant may rebudget funds within a total approved budget, subject to the prior approval requirements of 10 CFR § 600.114(b) and (e). The Participant shall obtain prior written approval of the DOE Contracting Officer of any budget revision which would result in the need for additional DOE funding.

(C) Additional Funds

The Participant shall immediately notify the DOE Contracting Officer in writing whenever it becomes apparent that the costs of completing that portion of the project to be performed during the budget period exceeds the total approved budget. Such written notice shall, at a minimum, set forth (1) a detailed explanation of the factors causing the cost overrun; (2) a proposed budget revision detailing the amount of additional funds needed to complete the project; and (3) the amount of additional DOE funds, if any, the Participant is requesting.

DOE is under no obligation to provide additional funds. Under no circumstances shall the Participant incur any additional costs to be cost shared by DOE under this Cooperative Agreement without the prior written approval of the DOE Contracting Officer.

(D) DOE/Participant Share of Additional Funds

DOE is under no obligation to award additional funds to pay for costs in excess of the Total Estimated Project Cost estimated as of the date of award. If additional DOE funds are awarded, DOE's share of the allowable costs will not exceed the DOE share of the Total Estimated Project Cost as shown in Article VII (B) as of the date of award. Under no circumstances will the total amount of additional DOE funds awarded exceed 25 percent of DOE's share of the Total Estimated Project Cost indicated at Block 17 of the initial Notice of Financial Assistance Award.

ARTICLE XIII — PAYMENT

(A) General

With the exception of the pre-award costs that will be reimbursed as provided in Article XI, DOE shall make advance payments by means of a letter of credit under which the Participant is authorized to draw Federal funds needed for immediate disbursement.

(B) Limitation on Expenditures

DOE funds may not be expended by the Participant on construction or operation unless and until the Contracting Officer notifies the Participant in writing that all DOE obligations under NEPA have been satisfied; however, once NEPA approval is obtained, DOE will share in

allowable Phase II project costs incurred prior to NEPA approval in accordance with the percentage set forth in Article VII (B).

ARTICLE XIV — RIGHTS IN INTELLECTUAL PROPERTY

The rights and obligations of the parties with respect to intellectual property are set forth in Attachment B to this Cooperative Agreement which is hereby incorporated by reference.

The Participant shall include applicable intellectual property clauses, pursuant to Attachment B, in any contract or subcontract under this Cooperative Agreement involving the conduct of research, development, or demonstration of the IGCC Technology.

ARTICLE XV — REPORTING REQUIREMENTS

Reports shall be submitted in accordance with the requirements of the Federal Assistance Reporting Checklist (Attachment C) which is hereby incorporated by reference.

ARTICLE XVI — PROCUREMENT

In selecting, awarding, and administering contracts under this Cooperative Agreement, the Participant shall abide by the requirements and goals set forth in this Article.

(A) Responsible Contractors

The Participant shall not award or approve or consent to the award of a contract to any party which is debarred or suspended or is excluded from or ineligible for participation in Federal assistance programs under the Government-wide Debarment and Suspension (Nonprocurement) rules at 10 CFR Part 1036. Copies of these rules; the DOE Consolidated List of Debarred, Suspended, Ineligible and Voluntarily Excluded Awardees (DOE List); and the General Services Administration's (GSA) List of Parties Excluded from Federal Procurement or Nonprocurement Programs (Nonprocurement List) may be obtained from the DOE Contracting Officer.

(B) Procurement Goals

Positive efforts shall be made to utilize small business and minority-owned business sources of supplies and services. Such efforts should allow these sources the maximum feasible opportunity to compete for contracts utilizing Federal funds.

(C) Contract Clauses

The Participant shall use the contract clauses in Attachment D which is hereby incorporated by reference.

ARTICLE XVII — INSURANCE AND INDEMNITY

In addition to any insurance which is required under Paragraph (A) and which may be required under Paragraph (B) of this Article, the Participant shall acquire and thereafter maintain workmen's compensation, employer's liability, comprehensive general liability (bodily injury), and comprehensive automobile liability (bodily injury and property damage) insurance, and such other insurance coverage as the Participant normally carries for similar projects. With the approval of the DOE Contracting Officer, the Participant may maintain a self-insurance program for any of the coverages specified in this Article; provided that, with respect to workmen's compensation, the Participant is qualified under applicable statutory and regulatory authority. All insurance required pursuant to the provisions of this Article shall be in such form, in such amounts, for such periods of time, and provided by such insurance carriers as the DOE Contracting Officer may approve.

(A) Hazards (Property Damage)

The Participant will provide hazard insurance (theft, fire, windstorm, water damage, etc.) covering the materials, equipment, and structures acquired or constructed under this Cooperative Agreement. Proceeds from such insurance may be used to replace or repair the damaged or destroyed property to the extent provided for in the applicable agreements between the Participant and any Project construction permanent/Project financing lenders. During the term of this Cooperative Agreement, if the Participant decides not to replace or repair the property, the insurance proceeds will be paid to any Project construction/permanent Project financing lenders, then to DOE and the Participant in such a way that the overall cost share ratio between DOE and the Participant is achieved. Any such payment of insurance proceeds to DOE shall constitute a credit against the Participant's obligation to DOE under the Repayment Agreement.

(B) Flood Insurance

If funds under this Cooperative Agreement are used to acquire or construct property or equipment for use in an identified flood plain area in the United States having special flood, special flood-related erosion, or special mudslide (i.e., mud-flow) hazards, the Participant shall obtain flood insurance as required by the Flood Disaster Protection Act of 1973 (42 U.S.C. 4002, 4012a, 4105), as amended. Proceeds from such insurance may be used to replace or repair the damaged or destroyed property to the extent provided for in the applicable agreements between the Participant and any Project construction/permanent Project financing lenders. During the term of this Cooperative Agreement, if the Participant decides not to replace or repair the property, the insurance proceeds will be paid to any Project construction/permanent Project financing lenders, then to DOE and the Participant in such a way that the overall cost share ratio between DOE and the Participant is achieved. Any such payment of insurance proceeds to DOE shall constitute a credit against the Participant's obligations to DOE under the Repayment Agreement.

(C) Indemnity

The Participant shall indemnify the Government and its officers, agents, or employees for any and all liability, including litigation expenses and attorneys' fees, arising from suits, actions, or claims of any character for death, bodily injury, or loss of or damage to property or to the environment, resulting from and to the extent of the fault or negligence of the Participant in performing the project under this Cooperative Agreement.

(D) Consequential Damages

In no event, whether as a result of breach of contract, warranty, the indemnity provided for in Article XVII (C), tort including negligence, strict liability or otherwise, shall Participant be liable to the Government for special, indirect, incidental, consequential, or exemplary damages, and the Government specifically waives its rights to seek such damages.

ARTICLE XVIII — BONDING FOR CONSTRUCTION

The Participant shall require any construction contractor or subcontractor to obtain performance and payment bonds for any construction project in accordance with practices approved by the Contracting Officer.

ARTICLE XIX — PROPERTY MANAGEMENT AND DISPOSITION

Title to all real property, equipment, and supplies (excluding Government-furnished property) acquired by or on behalf of the Participant in connection with performance of the project shall vest upon acquisition in the Participant. The Participant shall make such property available for use in the project. During the period of this Cooperative Agreement, the Participant may, with the DOE Contracting Officer's prior approval, encumber its title to or dispose of such property.

The use, management, and disposition of all Government-furnished property shall be governed by 10 CFR § 600.117.

ARTICLE XX — TERMINATION

(A) Termination by Mutual Agreement

This Cooperative Agreement shall be terminated by mutual agreement, only during first twelve (12) months of this Cooperative Agreement, if Participant fails to receive adequate assurance that the tax consequences of DOE's Project cost-sharing contributions will not be materially adverse to the Project and after discussion the parties are unable to overcome successfully the adverse effects of such rulings. This Cooperative Agreement may be terminated, in whole or in part, by mutual agreement at any time. The initiation and negotiation of such a termination shall be conducted in accordance with the procedures set forth in 10 CFR § 600.29(d). In the event of any such termination, the liability of DOE

shall be limited to its share of allowable costs incurred during the current or any previous budget period.

The Participant shall incur no new obligations after the effective date of termination of the Cooperative Agreement and shall cancel as many outstanding obligations as possible. Notwithstanding anything to the contrary in the fourth sentence of the first paragraph of this Article XX(A), DOE shall reimburse the Participant for the DOE share of non-cancellable obligations properly incurred prior to the effective date of the termination.

(B) Termination for Cause

DOE may terminate the Cooperative Agreement, in whole or in part, for cause (i.e., on the basis of a noncompliance determination). DOE shall provide advance written notice, as required by 10 CFR § 600.28, of any noncompliance determination (with a minimum 30-day opportunity to cure the noncompliance) and of any subsequent decision to terminate for cause. The Cooperative Agreement may not be terminated for cause if the Participant's failure to perform is excusable under the provisions of the clause entitled Excusable Delays (April 1984) at § 52.249-14 of the Federal Acquisition Regulation.

(C) Effect of Termination

DOE shall have no liability for paying the costs of any new obligations incurred by the Participant after the effective date of the termination of this Cooperative Agreement (or portion thereof). DOE shall pay its share of all noncancellable obligations properly incurred by the Participant before the effective date of the termination. The Participant shall have no obligation to repay to DOE any portion of DOE's Project cost-sharing contributions except to the extent provided for in the Repayment Agreement or as may be necessary as a result of the final audit of costs incurred under the Cooperative Agreement.

ARTICLE XXI — DISPUTES AND APPEALS

The Participant shall have the right, as specified in 10 CFR § 600.26, to appeal to the Financial Assistance Appeals Board (the Board) any of the following adverse determinations or decisions:

- (1) A determination that the Participant has failed to comply with the terms and conditions of this Cooperative Agreement, with the requirements of 10 CFR Part 600, or with the requirements of Public Law 100-446;
- (2) A DOE decision not to make a continuation award based on any of the determinations described in the preceding paragraph, including any determination that the Participant's performance of the project has not met the requirements of the approved Project Evaluation Plan;
- (3) A DOE termination of this Cooperative Agreement, in whole or in part, for cause;

- (4) A DOE determination that this Cooperative Agreement is void or invalid;
- (5) The application by DOE of an indirect cost rate; and
- (6) DOE disallowance of costs, including those incurred after selection but before award.

A DOE decision not to make a continuation award which is based on the unavailability of sufficient appropriated funds or on the failure to satisfy NEPA requirements may not be appealed to the Board.

ARTICLE XXII — RECORDS RETENTION, ACCESS, AND DISCLOSURE

(A) Period of Retention

The Participant shall retain all financial and performance records, supporting documents, statistical records, and other records of the Participant which are required to be retained by the terms of this Cooperative Agreement, and any other records the Participant reasonably considers to be pertinent to this Cooperative Agreement. The period of required retention shall be from the date each such record is created or received by the Participant until three years after one of the following dates, whichever is latest: the expiration date of this Cooperative Agreement; the date the Participant's final expenditure report is submitted to DOE; or if this Cooperative Agreement is terminated in its entirety, the effective date of the termination. If any claim, litigation, negotiation, investigation, audit, or other action involving the records starts before the expiration of the three-year retention period, the Participant shall retain the records until such action is completed and all related issues are resolved, or until the end of the three-year retention period, whichever is later.

(B) Authorized Copies

Copies made by microfilm, photocopying, or similar methods may be substituted for original records. Records originally created by computer may be retained on an electronic medium, provided such medium is "read only" or is protected in such a manner that the electronic record can be authenticated as an original record.

(C) Access to Records

DOE and the Comptroller General of the United States, or any of their authorized representatives, shall have the right of access to any books, documents, papers, or other records (including those on electronic media) which are pertinent to this Cooperative Agreement. The purpose of such access is limited to the making of audits, examinations, excerpts, and transcripts. The right of access described in this paragraph shall last as long as the Participant retains records which are pertinent to this Cooperative Agreement.

(D) Restrictions on Public Disclosure

The Federal Freedom of Information Act (5 U.S.C. § 552) does not apply to records the Participant is required to retain by the terms of this Cooperative Agreement. Unless otherwise required by law or a court of competent jurisdiction, the Participant shall not be required to disclose such records to the public.

ARTICLE XXIII — PUBLIC INFORMATION RELEASE

The Participant shall coordinate in advance with the DOE Contracting Officer or the COR on all information to be issued by the Participant to the public concerning work performed under this Cooperative Agreement. Information shall not be released to the public without first obtaining the approval of the DOE Contracting Officer or the COR.

ARTICLE XXIV — LEGAL NOTICE/DISCLAIMER

The following notice shall be contained in all reports intended to be released to the public:

This report was prepared by Clean Power Cogeneration Limited Partnership pursuant to a Cooperative Agreement partially funded by the U.S. Department of Energy, and neither Clean Power Cogeneration Limited Partnership nor any of its subcontractors nor the U.S. Department of Energy, nor any person acting on behalf of either:

- (A) Makes any warranty or representation, express or implied, with respect to the accuracy, completeness, or usefulness of the information contained in this report, or that the use of any information, apparatus, method, or process disclosed in this report may not infringe privately owned rights; or
- (B) Assumes any liabilities with respect to the use of, or for damages resulting from the use of, any information, apparatus, method or process disclosed in this report.

Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise, does not necessarily constitute or imply its endorsement, recommendation, or favoring by the U.S. Department of Energy. The views and opinions of authors expressed herein do not necessarily state or reflect those of the U.S. Department of Energy.

ARTICLE XXV — COMMERCIALIZATION

The Participant agrees to exercise its best efforts to commercialize, or to assist others to commercialize, in the United States, air blown IGCC technology in accordance with Attachment E.

ARTICLE XXVI — OPTION TO CONTINUE

Upon written request of the Participant, DOE may extend the final Budget Period of the project period in order to complete the work scope within the funds provided [Reference 10 CFR 600.31 (d) (2)].

ARTICLE XXVII — INTEREST

- (A) Notwithstanding any other term or condition of this Agreement, all amounts that become payable by the Participant to the Government under this Agreement shall bear simple interest from the date due until paid, unless paid within 30 days of becoming due. The interest rate shall be the interest rate established by the Secretary of the Treasury (Secretary) as provided in Section II of the Debt Collection Act of 1982 (31 U.S.C. 3717), which is applicable to the period in which the amount becomes due, as provided in Paragraph B of this provision, and then at the rate applicable for each 3-month period as fixed by the Secretary until the amount is paid.
- (B) Amounts shall be due at the earliest of the following dates:
- (1) The date fixed under this Agreement.
 - (2) The date of the first written demand for payment consistent with this Agreement, including any demand resulting from a termination.
 - (3) The date the Government transmits to the Participant a proposed agreement to confirm completed negotiations establishing the amount of debt.
- (C) The interest charge made under this provision may be reduced in accordance with the procedures prescribed in 4 CFR Paragraph 102.13 or in accordance with agency regulations in effect on the date of original award of this Agreement.
- (D) The requirements of this Article do not apply to any amounts due the Government under operation of the Repayment Agreement, DOE Instrument No. DE-FR21-91MC28149.000.

ARTICLE XXVIII — LIMITATION ON PAYMENTS TO INFLUENCE CERTAIN FEDERAL TRANSACTIONS

The Participant shall comply with the lobbying restrictions, certifications, and disclosure requirements found at 55 Federal Register 6736-6746 (February 26, 1990) to be codified at 10 CFR Part 601.

ARTICLE XXIX — PERFORMANCE GUARANTEE

The Participant as defined in Article II (K) agrees to assume all of the performance and liabilities as required in this Cooperative Agreement, including guarantees to capitalize the Participant's cost share and to commercialize IGCC technology (as defined in Paragraph 9 (a) (8) of Attachment B of this

Cooperative Agreement) in accordance with Attachment E of this Cooperative Agreement.

ARTICLE XXX — REPAYMENT

The Participant shall be obligated to repay the Government in accordance with the terms and conditions of the Repayment Agreement, DOE Instrument No. DE-FR21-91MC28149.000.

ARTICLE XXXI — SPECIAL SURVEILLANCE SUBCONTRACTS

The following named contracts, subcontracts, and agreements require prior review and approval by the Contracting Officer before execution. The Contracting Officer may at a later time designate other contracts, subcontracts, or licensing agreements as requiring the Contracting Officer's review and approval.

- Lurgi gasifier subcontract and licensing agreement.
- GEESI hot gas cleanup subcontract.
- Combined cycle subcontract utilizing a GE turbine.
- Briquetting subcontract.
- SCR subcontract.
- CRSS Capital subcontract.
- CRSS Engineers subcontract.
- TECO Power Services subcontract.
- Administrative services.
- Operating and maintenance.
- BOP engineering services.
- Fines subcontract.
- Power purchase.
- Fuel supply.
- Site access.
- Tail gas processing
- QF steam host arrangements.

TAMPA ELECTRIC COMPANY
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PAGE 28 OF 40

DOCUMENT 4-2

**COPY OF THE U. S. DEPARTMENT OF ENERGY
COOPERATIVE AGREEMENT MODIFICATION**

CHANGING THE PARTICIPANT

FROM

CLEAN POWER COGENERATION, INCORPORATED

TO

TAMPA ELECTRIC COMPANY

March 5, 1992

COOPERATIVE AGREEMENT MODIFICATION (2/25/92) --

Instrument # DE-FC21-91MC27363

Amendment No. M001

The purpose of this amendment is to change the Participant, the project site and the gasification technology of Cooperative Agreement DE-FC21-91MC27363. Accordingly the agreement is hereby modified as follows:

COVER PAGES

Page Section

Title "CPC AIR-BLOWN" is deleted and "CLEAN POWER COGENERATION, INCORPORATED" is changed to "TAMPA ELECTRIC COMPANY."

i & ii Header, "CLEAN POWER COGENERATION, INCORPORATED" is changed to "TAMPA ELECTRIC COMPANY" and "AIR BLOWN" is deleted.

SCHEDULE OF ARTICLES

Page Section

1 Article I (A), "air blown fixed-bed" is changed to "oxygen blown entrained-flow" in 2 places.

1 Article I (B), "air blown fixed-bed" and "air-blown" is changed to "oxygen blown entrained-flow." Third sentence is changed to read: "The integrated performance to be demonstrated will include all major subsystems in the IGCC system entailing coal feeding; a pressurized, oxygen blown entrained-flow gasifier capable of utilizing caking coal; an air separation system to provide oxygen to the gasifier as an oxidant and also to provide nitrogen to the combustion turbine for NOx control and power augmentation; a cold gas cleanup system capable of full flow in parallel with hot gas cleanup train capable of a nominal 46 percent flow for removing sulfur compounds, particulates, and other contaminants as necessary to meet environmental and combustion turbine fuel requirements; an advanced combustion turbine appropriately modified to utilize low-Btu coal gas as fuel; the heat recovery steam generation system; the steam cycle; all control systems; and the balance of plant."

2 Article II (K) is changed to read: "'Participant" means Tampa Electric Company and its successors and assigns."

- 2 Article II (L) is changed to read: "IGCC Technology" as used in the Cooperative Agreement means all of the patented and/or unpatented technical data and know-how required to design, procure, construct, and operate an integrated coal gasification combined-cycle system comprised of the following basic elements and process: a pressurized, oxygen-blown, entrained-flow gasifier, capable of utilizing caking coal which is gasified in the presence of oxygen to produce a hot product gas mixture composed substantially of hydrogen and carbon monoxide; a commercially available cold gas cleanup system or a metal oxide hot gas conditioning system for removing sulfur compounds, particulates, and other contaminants as necessary to meet environmental and turbine fuel requirements; a combined-cycle power generation system wherein the cleaned product gas is combusted in an advanced combustion turbine generator to make electrical power and wherein steam, produced from a heat-recovery steam generator in the combustion turbine exhaust, is used in part to feed a steam turbine generator to generate a second source of electrical power; an integrated air separation process for removing oxygen and nitrogen from ambient air and supplying oxygen to the gasification unit as an oxidant while simultaneously supplying nitrogen to the combustion turbine for NOx control and power augmentation; and the control system and algorithms necessary to integrate and control the overall system as required by the operator, as demonstrated under this Cooperative Agreement including any improvements or modification embodied during commercialization by/or through the Participant which is incorporated into the system."
- 3 Article II (Q) is changed to read "Repayment Agreement" means the agreement made by the Participant in DOE Instrument Number DE-FR21-91MC28149.000 in March 1991 as amended by Modification M001 to this agreement (dated March 5, 1992), to repay the DOE share of costs paid under this Cooperative Agreement."
- 3 Article II (T) is changed to read "Facility" means the portion of Participant's Polk County, Florida power plant required to complete the IGCC Technology work under this Cooperative Agreement."
- 3 Article II (U) is added to read: "TPS" means TECO Power Services Corporation, an affiliated company within the same corporate organization as the Participant and 100 percent owner of all stock of all of the Corporate Partners of Clean Power Cogeneration Limited Partnership."
- 4 Article III (A), a third paragraph is added to read: "The Participant has entered into a Project Management Agreement with TPS under which TPS will be the Participant's

representative with DOE with respect to technical matters and other day to day activities. Such person shall be designated as a Technical Representative in Article V hereof."

- 5 Article V, 2nd sentence, "or Technical Representative" is inserted after "Project Manager."
- 6 Article V, "J. Charles Hester" is changed to Charles R. Black, "Project Manager Clean Power Cogeneration, Inc." is changed to "Project Director Tampa Electric Company" and "Associate Project Manager Clean Power Cogeneration, Inc." is changed to "Associate Project Director and Technical Representative TECO Power Services."
- 6 Article VI, "City of Tallahassee's Arvah B. Hopkins Power Station, Tallahassee, Florida" is changed to "Tampa Electric Company's power plant site in Polk County, Florida."
- 6 Article VII (B), the total project duration is changed from "60" to "81" months, Phase I is changed from "33" to "51" months, Phase II is changed from "24" to "30" months and Phase I and II overlap is changed from "21" to "24" months.
- 7 Article VII (C), Budget Period 1 is changed from "18" to "33" months and Budget Period 2 is changed from "18" to "24" months.
- 7 Article VII (D), Phase I DOE and Participant cost shares are changed from "\$8,050,000" to "\$13,145,000" and Phase II DOE and Participant cost shares are changed from "\$91,679,000" to "\$86,584,000."
- 10 Article X (B) (8) is changed to read: "Except as defined below in Article X (C) (7), the Government will not pay costs for fuel and other variable operating expenses when the turbine is being fired solely on natural gas, fuel oil or a natural gas/fuel oil combination or when the hot gas cleanup system is not in operation."
- 10 Article X (B) (10) is added to read: "The Government will not pay costs associated with a cold gas cleanup system nor certain prorated portions of other systems, except as defined below in Article X (C) (8)."
- 11 Article X (C) (7) is modified to insert "with hot gas cleanup" after "primary fuel" where appearing and to insert "or fuel oil" after the first mention of "natural gas."
- 11 Article X (C) (8) is added to read: "All of the hot gas cleanup subsystem and forty (40) percent of the oxygen plant, coal handling, gasification and combined cycle

subsystems incurred costs are allowable for cost sharing during Phase I and Phase II activities. Forty-six (46) percent of the total plant operating costs are allowable for cost sharing during Phase III."

- 15 Article XVII (D) is deleted in its entirety.
- 15 Article XX (A), first sentence is deleted.
- 18 Article XXIV, "Clean Power Cogeneration limited Partnership" is changed to "Tampa Electric Company" in 2 places.
- 18 Article XXV, "air blown" is deleted.
- 19 Article XXIX, "IGCC technology" is changed to "IGCC Technology."
- 20 Article XXX, "as amended by Modification M001 to this Repayment Agreement (dated March 5, 1992)" is added.
- 20 Article XXXI, "Lurgi" is changed to "Texaco"; "Briquetting subcontract.", "SCR subcontract." and "CRSS Capital subcontract." are deleted; "CRSS Engineers subcontract" is changed to "Architect engineer subcontract"; "TECO Power Services subcontract." is changed to "TPS subcontracts for project management and commercialization."; "Administrative services.", "Operating and maintenance.", "Fines subcontract.", "Power purchase.", "Site access" and "QF steam host arrangements." are deleted; and "Coal handling subcontract", "Air separation unit subcontract", "Slag and sulfur byproducts contracts" and "Environmental services subcontract" are added.
- 21 Article XXXII is deleted in its entirety.
- 21 ARTICLE XXXIII, a new paragraph is added to read:
"Notwithstanding the provisions of Article VIII (B) and (C) hereof, the terms and conditions hereof constitute the entire agreement between the parties, and cannot be changed, modified, altered or amended (collectively, "Amendments") unless it is done so in writing signed by both parties. The basis for and such Amendments shall be limited to matters requiring additions or deletions to Cooperative Agreements under this program. This Agreement may be terminated only in accordance with Article XX hereof."
- 21 Article XXXIV is added as follows:

"Article XXXIV - Incremental Funding - Limitation of Funds

Remaining funding for Budget Period 1, anticipated to be available during the second quarter of FY92, will be

obligated as the funds become available. The Participant shall promptly notify the Contacting Officer in writing of the estimated amount of additional funds, if any, are required to continue timely performance under this agreement and when the funds will be required. The maximum DOE obligation to the Participant during Budget Period 1 is shown in Block 16 of the DOE form 4600.1. The Government is not obligated to increase the total dollar amount funded for Budget Period 1 above the amount specified in Block 16 of the DOE Form 4600.1 and the Participant is not obligated to continue performance under this agreement or otherwise incur costs in excess of the amount obligated by the Government plus the Participants corresponding share."

ATTACHMENT A - STATEMENT OF WORK

Page Section

- A-1 Title - "Air Blown" is deleted.
- A-1 Objective, 2nd line, "a fixed-bed," is changed to "an."
- A-1 Paragraph A., 1st sentence, "air blown" is deleted and the sub-paragraphs are changed to read:

The project, to be located at Tampa Electric's power plant site in Polk County, Florida, will convert approximately 1900 tons per day of 0.5 to 3.5 percent sulfur coal to provide a nominal 260 MWe of electric power.

The integrated performance to be demonstrated will include all major subsystems in the IGCC system entailing coal feeding; a pressurized, oxygen blown entrained-flow gasifier capable of utilizing caking coal; an air separation system to provide oxygen to the gasifier as an oxidant and also to provide nitrogen to the combustion turbine for NOx control and power augmentation; a cold gas conditioning system capable of full flow in parallel with hot gas cleanup train capable of a nominal 46 percent flow for removing sulfur compounds, particulates, and other contaminants as necessary to meet environmental and combustion turbine fuel requirements; an advanced combustion turbine appropriately modified to utilize low-Btu coal gas as fuel; the heat recovery steam generation system; the steam cycle; all control systems; and the balance of plant."

- A-2 Paragraph C, 1st sub-paragraph, "eighteen (18) months" is changed to "thirty-three (33) months" and in 2nd

subparagraph "eighteen (18) months" is changed to "twenty-four (24) months."

- A-2 Paragraph D, "Project Manager" is changed to "Project Director" in three places.
- A-4 Task 1.0, "a 120 MWe air blown IGCC power plant at the Arvah B. Hopkins Power Station, located outside of Tallahassee, Florida" is changed to "an oxygen blown entrained-flow IGCC Facility at Tampa Electric's power plant site located in Polk County, Florida."
- A-4 Task 1.1, 3rd sentence, "satisfying the requirements of all project investors and debt financing" is changed to "proceeding to Budget Period 2."
- A-4 Task 1.2, the following is added to the Preliminary Plant Design task description, "The Participant is responsible for a design study which evaluates the feasibility of incorporating a full or partial humid air cycle (HAT) in a potential commercial application of the IGCC Technology and for preparation of a study report. (Any implementation of a HAT cycle demonstration would be subject to terms to be mutually agreed between DOE and the Participant at the end of the preliminary design phase.)"
- A-5 Task 2.1, the following is added to the Plant Construction task description, "The Participant shall make provisions for supply and return connections appropriately located as part of the Facility and designate an on-site location necessary to accommodate a potential future slip stream test of a fuel cell module for use of coal gas from the gasification portion of the project. (Any installation of a module for demonstration of an integrated gasification fuel cell module would be during the demonstration phase of this project and would be subject to terms then mutually agreed to by the Participant and DOE.)"

ATTACHMENT B - INTELLECTUAL PROPERTY PROVISIONS

Page Section

- B-4 Article 8 (a) (6) is changed to read: "'IGCC Technology" as used in the Cooperative Agreement means all of the patented and/or unpatented technical data and know-how required to design, procure, construct, and operate an integrated coal gasification combined-cycle system comprised of the following basic elements and process: a pressurized, oxygen-blown, entrained-flow gasifier, capable of utilizing caking coal which is gasified in the presence of oxygen to produce a hot product gas mixture composed substantially of

hydrogen and carbon monoxide; a commercially available cold gas cleanup system or a metal oxide hot gas conditioning system for removing sulfur compounds, particulates, and other contaminants as necessary to meet environmental and turbine fuel requirements; a combined-cycle power generation system wherein the cleaned product gas is combusted in an advanced combustion turbine generator to make electrical power and wherein steam, produced from a heat-recovery steam generator in the combustion turbine exhaust, is used in part to feed a steam turbine generator to generate a second source of electrical power; an integrated air separation process for removing oxygen and nitrogen from ambient air and supplying oxygen to the gasification unit as an oxidant while simultaneously supplying nitrogen to the combustion turbine for NOx control and power augmentation; and the control system and algorithms necessary to integrate and control the overall system as required by the operator, as demonstrated under this Cooperative Agreement including any improvements or modification embodied during commercialization by/or through the Participant which is incorporated into the system."

- B-5 Article 8 (a) (7) is changed to read "'Facility" means the portion of Participant's Polk County, Florida power plant required to complete the IGCC Technology work under this Cooperative Agreement."
- B-5 Article 8 (a) (8) is added to read: "'TPS" means TECO Power Services, an affiliated company within the same corporate organization as the Participant and 100 percent owner of all stock of all of the Corporate Partners of Clean Power Cogeneration Limited Partnership."
- B-18 In Article 8 (k) (1), "(CPC, CRSS Capital, Inc., TECO Power Services, Inc.)" is changed to "or TPS."
- B-20 Article 9 (a) (4) is changed to read: "'Cooperative Agreement" means this agreement between the DOE and the Participant, DOE instrument Number DE-FC21-91MC27363.000 as novated on March 5, 1992, and any subsequent amendments."
- B-20 Article 9 (a) (5) is changed to read: "'Facility" means the portion of Participant's Polk County, Florida power plant required to complete the IGCC Technology work under this Cooperative Agreement."
- B-20 Article 9 (a) (8) is changed to read: "'IGCC Technology" as used in the Cooperative Agreement means all of the patented and/or unpatented technical data and know-how required to design, procure, construct, and operate an integrated coal gasification combined-cycle system comprised of the following basic elements and process: a pressurized,

oxygen-blown, entrained-flow gasifier, capable of utilizing caking coal which is gasified in the presence of oxygen to produce a hot product gas mixture composed substantially of hydrogen and carbon monoxide; a commercially available cold gas cleanup system or a metal oxide hot gas conditioning system for removing sulfur compounds, particulates, and other contaminants as necessary to meet environmental and turbine fuel requirements; a combined-cycle power generation system wherein the cleaned product gas is combusted in an advanced combustion turbine generator to make electrical power and wherein steam, produced from a heat-recovery steam generator in the combustion turbine exhaust, is used in part to feed a steam turbine generator to generate a second source of electrical power; an integrated air separation process for removing oxygen and nitrogen from ambient air and supplying oxygen to the gasification unit as an oxidant while simultaneously supplying nitrogen to the combustion turbine for NOx control and power augmentation; and the control system and algorithms necessary to integrate and control the overall system as required by the operator, as demonstrated under this Cooperative Agreement including any improvements or modification embodied during commercialization by/or through the Participant which is incorporated into the system."

B-21 Article 9 (a) (9) is changed to read: "'Participant" means Tampa Electric Company and its successors and assigns."

B-26 Article 9 (j), "Air Blown" is deleted from the title and "air-blown" is deleted in 7 places in the text.

B'-1 NON-DISCLOSURE AGREEMENT, "CLEAN POWER COGENERATION LIMITED PARTNERSHIP - CLEAN POWER COGENERATION, INC., GENERAL PARTNER" is changed to "TAMPA ELECTRIC COMPANY" and "the Clean Power Cogeneration, Inc." is changed to "Tampa Electric Company."

ATTACHMENT C - REPORTING REQUIREMENTS

Page Section

C-2 "Air Blown" is deleted from the title.

ATTACHMENT E - COMMERCIALIZATION AND PERFORMANCE ARRANGEMENTS

Attachment E is modified in its entirety to read as follows:

Attachment B to the Repayment Agreement is changed in its entirety to read as follows:

"ATTACHMENT B

ENTITIES SUBJECT TO REPORTING REQUIREMENTS OF LICENSE FEES

Tampa Electric Company
TECO Power Services Corporation"

Attachment C to the Repayment Agreement is changed in its entirety to read as follows:

"ATTACHMENT C

COMMERCIALIZATION AND PERFORMANCE AGREEMENTS

IGCC DEMONSTRATION PROJECT

In consideration that the U.S. Department of Energy (DOE), under the authority of DOE solicitation, Program Opportunity Notice (PON), DE-PS01-89FE61825, is entering into a novated Cooperative Agreement DE-FC21-91MC27363 as amended by Modification M001 (Novation Agreement dated March 5, 1992) with Tampa Electric Company ("Tampa Electric"), and that TECO Power Services Corporation (TPS), together with the DOE has an interest in the development, implementation and commercialization of advanced integrated coal gasification combined-cycle power generation systems, as defined as the Demonstration Technology in the novated Repayment Agreement DE-FR21-91MC28149 as amended by Modification M001 (Novation Agreement dated March 5, 1992) with Tampa Electric, the following is hereby acknowledged and agreed:

1.0 Commercialization of the Demonstration Technology

- (a) In addition to or in assistance of any rights acquired by the Government in IGCC Technology from the Participant under paragraph (k) of the Cooperative Agreement's Patents Clause and paragraph (h) of the Cooperative Agreement's Rights in Technical Data Clause, the Participant agrees to negotiate in good faith with a responsible applicant and to conclude an agreement with such applicant to provide a commercial-size facility incorporating IGCC Technology or portion of the IGCC System in the United States equal to or a scaled-up or modified version of the Facility which is the subject of the Cooperative Agreement. The Agreement shall, as appropriate to the circumstances, include provisions for licensing patented and unpatented IGCC Technology including background patents, waived subject inventions, proprietary data, know-how

and copyrighted works including improvements or enhancements of any of the foregoing as well as provisions for technical assistance and training.

- (b) The services and/or licenses specified in paragraph (a) of Section 1.0 shall be made available to responsible applicants to construct or have constructed, operate or have operated a facility incorporating IGCC Technology in the United States under reasonable terms and conditions taking into consideration accepted licensing standards or norms in the relevant U.S. industry as well as accepted levels of return on investment for such activities and/or services.
- (c) In the event that the Participant and the applicant cannot reach agreement after one year from the start of diligent and responsible negotiations between them, then the DOE by its Secretary or designee, reserves the option to submit, with the approval of the said applicant, unresolved licensing issues to arbitration in New York under the rules of the American Arbitration Association. The Participant agrees to be bound by the results of the Arbitration to the same extent that the Applicant agrees to be bound.
- (d) The provisions of paragraphs (a), (b), and (c) shall not apply as long as the Participant or its licensees are supplying U.S. market needs at reasonable prices for IGCC systems.
- (e) The Participant agrees to obtain sufficient rights to meet its commitments to commercialize and/or license IGCC Technology in accordance with the commercialization and performance arrangements set out in Section 2.0 hereof.

2.0 Performance Responsibilities

- (a) Tampa Electric and TPS shall make reasonable efforts to successfully demonstrate hot gas clean up in accordance with the requirements of the Cooperative Agreement in the first unit at the Polk County site. To the extent that the Demonstration Technology is determined by the Participant to be commercially reasonable in view of the technology, economics, performance, and specific capacity requirements, the Participant will, subject to approval by the Florida Public Service Commission, incorporate the Demonstration Technology in subsequent Generation Expansion plans as may be appropriate for future capacity addition requirements, and TPS agrees to incorporate these in commercialization efforts required by the Commercialization and Performance

Agreements and Repayment Agreement which are part of the Cooperative Agreement, consistent with good engineering practice and subject to the demands of the marketplace.

- (b) Tampa Electric will provide to TPS such rights in the IGCC Technology as are obtained from third parties, together with such rights as are developed by Tampa Electric as a result of the execution of the Cooperative Agreement in order that such technology may be marketed and commercialized by TPS.
- (c) TPS will market, sell, or make available as appropriate for market and sale commercial versions of the IGCC Technology, as determined to be commercially reasonable in view of the technology, economics and performance.
- (d) TPS will remit to Tampa Electric the amounts set forth in Article V of the Repayment Agreement that are due to DOE as a result of TPS's commercialization activities in accordance with paragraph (b) hereof in time sufficient for Tampa Electric to transmit such amounts to DOE in satisfaction of its obligations under the Repayment Agreement.
- (e) TPS will use its reasonable efforts to evaluate and develop, as appropriate, commercial versions of the IGCC Technology for future supply to the power industry, in both U.S. and foreign markets, as determined by it to be commercially reasonable in view of the technology, economics and performance.
- (f) TPS will establish a liaison to Tampa Electric Company for the purpose of making such IGCC Technology available to the utility industry.
- (g) Tampa Electric will cooperate with TPS in its commercialization efforts by making available to it pertinent operating data and by making its IGCC Facility available for inspection by potential purchasers, licensees or users of the IGCC Technology.
- (h) As used herein "commercialization" means compliance with the terms and conditions of Paragraph (j) -- Rights to Technical Data Clause of Attachment B of the Cooperative Agreement.

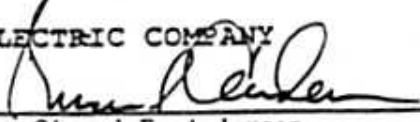
3.0 Binding Agreement

This Agreement when signed by responsible officials of Tampa Electric Company and TPS, who have authority to legally bind their respective organizations and when approved by a

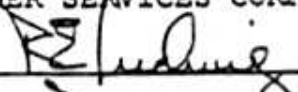
responsible officer of the DOE will be incorporated by reference and form part of the Repayment Agreement between the DOE and Tampa Electric.

IN WITNESS WHEREOF, the Parties hereto have executed this document as of the effective date of the Repayment Agreement.

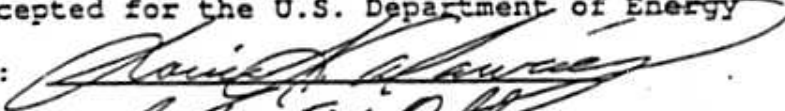
TAMPA ELECTRIC COMPANY

By: 
Girard F. Anderson
Title: President
Date: 3-5-92

TECO POWER SERVICES CORPORATION

By: 
Title: PRESIDENT
Date: 3/5/92

Accepted for the U.S. Department of Energy

By: 
Title: Contracting Officer
Date: 3/5/92

15. Please provide a calculation of the Polk Unit's currently projected equivalent availability factor. Is the current equivalent availability factor different from what was assumed in Docket No. 910883-EI? If so, please provide a detailed explanation of the differences. Also, please provide the currently projected individual equivalent availabilities for the air separation unit, the coal gasifier, the sulfuric acid plant, and the power block.

Please provide a detailed discussion as to how the use of a single slurry pump for the gasifier affects the Polk unit's equivalent availability factor.

A. Comparison of Polk Unit 1 Availability

The current expectation of the Polk IGCC unit availability is different than the availability assumptions used in the Determination of Need proceedings (Docket No. 910883-EI). The two primary reasons for the difference are in the change in the construction plan and the level of engineering design data at the time of the Need Hearing.

Initially, the IGCC construction plan was based on a commercial operation date of July 1995 for the advanced combustion turbine, and July 1996 for the balance of plant. This would have resulted in simple cycle operation of the combustion turbine on distillate oil as shown in Table 15-1 for approximately one year and the associated availability of only the combustion turbine. The current plan is based on a commercial operation date of October 1996 for the combined cycle using gasified coal as the primary fuel and distillate oil as the secondary fuel as shown in Table 15-2. The operation of the combustion turbine in a simple cycle mode is not a cost effective alternative. However, the operation of the combustion turbine in a combined cycle mode on distillate oil is cost effective at times when the coal gasification system is unavailable and the system needs the generation from the Polk 1 unit. Since the combined cycle power block can be operated when the gasification system is unavailable, the equivalent availability shown in Table 15-2 is higher than the availability of the combined cycle using only gasified coal.

The IGCC initial availability estimate was made by Texaco early in the preliminary design phase. The Polk details had not yet been developed at this stage, so this estimate reflected Texaco's expectations for a mature IGCC plant of their generic configuration and design. This estimate was sufficient for initial project planning purposes. However, as Polk's detailed design progressed, Tampa Electric Company found it necessary for planning purposes to develop an availability estimate which reflected some known factors such as lower availability during the two-year Department of Energy demonstration period.

Projected Individual Component Equivalent Availabilities

There was only one IGCC plant with sufficient operating experience and reliability data to serve as a basis for this estimate: Cool Water. Cool Water was a 100 MW IGCC power plant which operated for four and one-half years commencing in 1984. It consisted of a dedicated oxygen plant, an oxygen blown Texaco gasifier with full heat recovery, and a General Electric combined cycle; so it was very close to Polk's configuration. Cool Water's reliability and reliability growth have been well documented in public reports and in an extensive proprietary data base which carefully identifies durations and causes of each outage. This data was the basis for the most recent Polk projections.

The approach taken in making the Polk projections entailed considering every Cool Water outage by cause and duration, and adjusting them according to differences between Polk and Cool Water configurations, specific hardware, and experience level. This approach differs from mathematically combining availability statistics of the individual plant components or subsections. The methodology used for the Polk projections made it much easier to deal with the extensive "masking" (interactions between plant subsection or component outage data) that takes place in an IGCC plant and the heavy dependence of the predicted result on the highly variable and potentially long start-up times of two of the three major plant subsections (air separation and gasification). Consequently, individual subsection or component availabilities were not developed for the Polk availability estimate. Instead, an overall IGCC availability estimate was developed, as shown in the following table.

TABLE 15-1
POLK IGCC NEED HEARING AVAILABILITY ESTIMATE

159 MW CT-Oil (1)				
Operating Year	Equivalent Unplanned Outages (Hours)	Planned Outages (Hours)	Total Unavailability (Hours)	EAF (%)
1	295	370	664	92.4
2	N/A	N/A	N/A	N/A
3	N/A	N/A	N/A	N/A
Mature Plant	N/A	N/A	N/A	N/A

260 MW CC-Coal (2)				
Operating Year	Equivalent Unplanned Outages (Hours)	Planned Outages (Hours)	Total Unavailability (Hours)	EAF (%)
1	N/A	N/A	N/A	N/A
2	1,012	740	1,752	80
3	1,012	740	1,752	80
Mature Plant	1,012	740	1,752	80

220 MW CC-Oil (2)				
Operating Year	Equivalent Unplanned Outages (Hours)	Planned Outages (Hours)	Total Unavailability (Hours)	EAF (%)
1	N/A	N/A	N/A	N/A
2	461	370	831	90.5
3	461	370	831	90.5
Mature Plant	461	370	831	90.5

NOTES:

- (1) The Polk IGCC unit was planned as phased construction at the time of the Need Hearing, with the advanced combustion turbine in-service date by July 1995 and the balance of plant by July 1996. Beyond the first year of operation, the combustion turbine will not be operated in a simple cycle mode.
- (2) The combined cycle-coal availability is shown lower than the combined cycle-oil availability due to the expected higher maintenance requirements of the coal gasification system.

TABLE 15-2
POLK IGCC CURRENT AVAILABILITY ESTIMATE

159 MW CT-Oil (1)				
Operating Year	Equivalent Unplanned Outages (Hours)	Planned Outages (Hours)	Total Unavailability (Hours)	EAF (%)
1	N/A	N/A	N/A	N/A
2	N/A	N/A	N/A	N/A
3	N/A	N/A	N/A	N/A
Mature Plant	N/A	N/A	N/A	N/A

250 MW CC-Coal (2)				
Operating Year	Equivalent Unplanned Outages (Hours)	Planned Outages (Hours)	Total Unavailability (Hours)	EAF (%)
1	2,916	720	3,636	58.5
2	2,125	432	2,557	70.8
3	915	720	1,635	81.3
Mature Plant	854	720	1,574	82.0

210 MW CC-Oil (2)				
Operating Year	Equivalent Unplanned Outages (Hours)	Planned Outages (Hours)	Total Unavailability (Hours)	EAF (%)
1	540	336	876	90.0
2	540	336	876	90.0
3	540	336	876	90.0
Mature Plant	540	336	876	90.0

NOTES:

- (1) The current Polk IGCC unit construction plan deferred the advanced combustion turbine and balance of plant to a commercial operation date of October 1996. The combustion turbine will not be operated in a simple cycle mode.
- (2) The combined cycle-coal availability is shown lower than the combined cycle-oil availability due to the expected higher maintenance requirements of the coal gasification system.

Gasifier Slurry Pump

The basis for determining overall unit availability has primarily been comparison to the Cool Water gasification plant for similar equipment, and engineering judgment based on specific equipment history. Polk Unit 1 incorporates a single high quality diaphragm pump in slurry charge service. This pump, manufactured by GEHO, is considerably more reliable than the pumps in similar service at Cool Water (based on current industry experience). Consequently, mechanical pump failures will be significantly lower at Polk in the early years of operation.

While evaluating one vs. two-pump availability effects, many factors were considered: (1) specific GEHO operating characteristics, (2) experience at other Texaco licensed facilities, and (3) overall unit preventive maintenance and operating philosophy (i.e., effects of short duration trips, etc. on overall unit availability). Based on all of these factors, the increased availability offered by installing a second pump does not justify the additional cost.

While all of the data supports the decision to install a single slurry charge pump, the Polk design does allow for the addition of a second pump if actual operating conditions warrant it in the future. The availability and economic impacts of a single pump will be closely monitored to determine if there is a need for a second pump.

16. Please provide a detailed description and breakdown of the cost of the transloading equipment installed at the Big Bend Station in order to provide fuel to the Polk unit. Please identify how TECO will seek recovery of these costs.

A. The transloading equipment installed at Big Bend Station enables Tampa Electric to receive barged coal for delivery to the Polk Power Station. The coal will be off-loaded from barges by existing conveyors and stacked out at the east end of the coalfield. The coal will be reclaimed by existing equipment to the north blending bin which will be divided. Upgraded existing coal feeders will transfer the coal via a new conveyor to a new weigh bin which will transfer the coal into the trucks. The transloading project scope also includes upgrading the four existing coal blending bin feeders to maintain Big Bend Station's blending capabilities, road improvements, retaining walls, a truck wash station, fence and gate relocation, and roadway lighting.

The cost for the transloading project is estimated to be \$3.04 million.

<u>Cost Breakdown</u>	<u>\$ x 1,000</u>
Architect/Engineer Services	\$ 273
Site Work (roads and ponds)	590
Design, Fabricate and Erect Transloading Equipment	1,510
Additional equipment purchases and subcontracted support	710
TECO Project Management Engineering and construction support	547
AFUDC	<u>140</u>
Subtotal Project	3,771
DOE Approved Cost Cofunding	<u>(726)</u>
Net Project Costs	\$3,045

TAMPA ELECTRIC COMPANY
DOCKET NO. 950379-EI
STAFF'S SECOND SET
INTERROGATORY NO. 16
SPONSOR: BLACK
PAGE 2 OF 2

Tampa Electric will not seek new revenues under either the fuel or environmental adjustment clauses. Tampa Electric will include the costs for the transloading project in its rate base for surveillance reporting. Recovery will be sought through base rates as Tampa Electric's need for revenue requirements dictates.

**TAMPA ELECTRIC COMPANY
DOCKET NO. 950379-EI
STAFF'S SECOND SET
INTERROGATORY NO. 25
SPONSOR: BLACK
PAGE 1 OF 4**

25. Please provide a line diagram showing the energy balance, in BTUs for each major component of the Polk Unit IGCC plant at full load. This should include the fuel input, energy output, and all internal energy requirements.

A. Explanation of tables that follow on pages 2-4.

Table 25-1 is a block diagram showing the three major sections of the Polk County IGCC Plant which are:

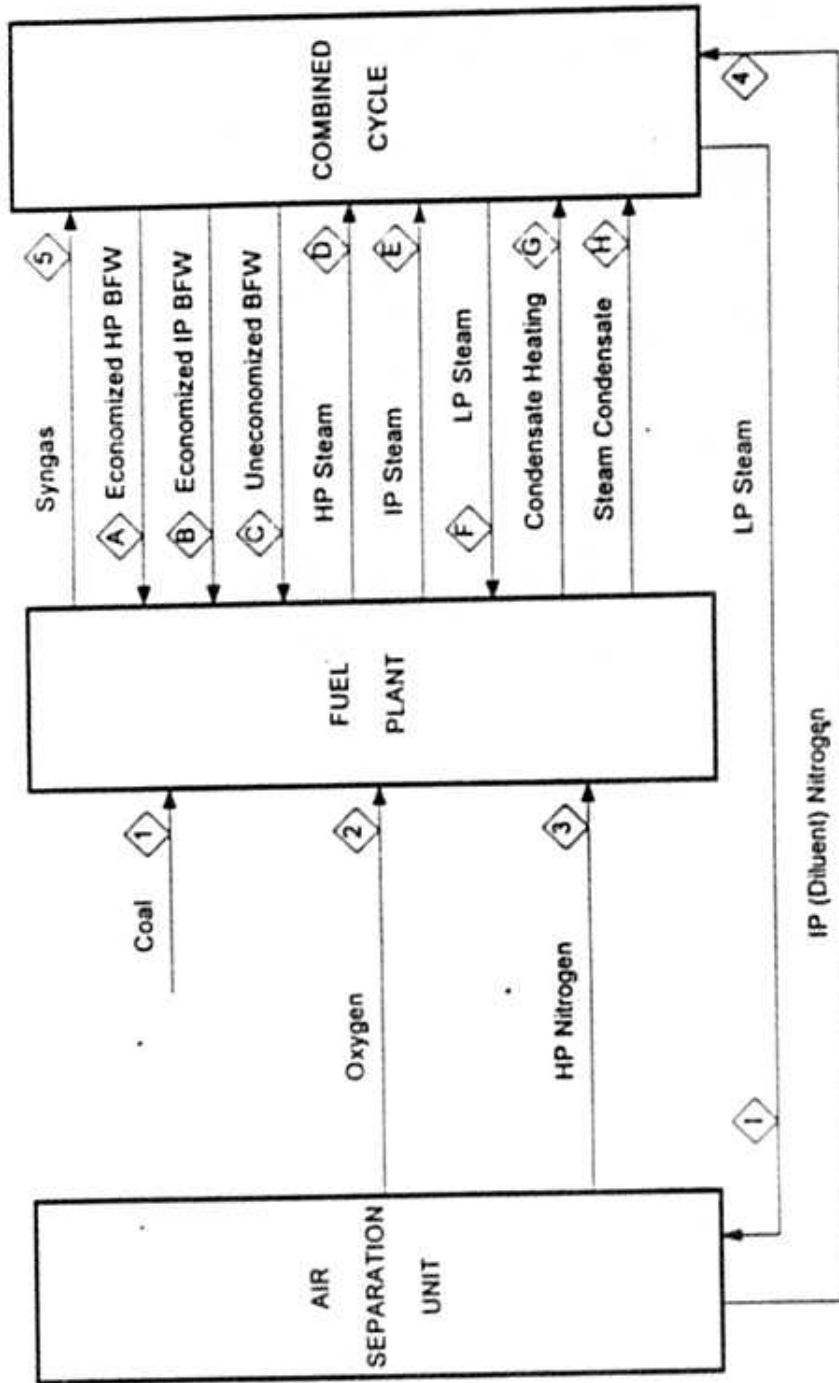
- o the Oxygen Plant, also referred to as the air separation unit,
- o the Fuel Plant which contains coal receiving and handling, slurry preparation, gasification, gas cooling, acid gas removal, sulfuric acid plant, and the process water systems,
- o the Combined Cycle Plant which contains the combustion and steam turbines, heat recovery steam generator, and boiler feedwater systems.

Also shown on that table are the main interconnecting energy flow streams (except electricity) between these three sections.

Table 25-2 quantifies the energy flow for each stream shown on Table 25-1. The energy flows are given in million BTUs per hour, and the reference states are identified on the table.

Finally, electricity production and consumption estimates are presented in Table 25-3. In some cases these electricity estimates are given at the component level for the important producers and consumers.

TABLE 25-1



Tampa Electric Company POLK COUNTY IGCC MAIN INTERFACE FLOWS

TABLE 25-2

POLK COUNTY IGCC - INTEGRATED PLANT PERFORMANCE PROJECTION
 PITT 8 NOC Coal, Expected Gasifier Conditions, 90F Ambient

MAIN INTERFACE STREAMS - HEAT CONTENT

DESCRIPTION	STREAM NUMBER	HEAT CONTENT (MMBTU/Hr)	
		Thermal (1) (2)	HHV
Raw Coal	1		2185.6
Oxygen	2	6.7	
HP Nitrogen	3	2.5	
IP Nitrogen	4	71.0	
Syngas	5	68.1	1683.9
Economized HP BFW To Process	A	-271.4	
Economized IP BFW To Process	B	-21.9	
Uneconomized BFW To Process	C	-6.6	
HP Steam From Process	D	516.0	
IP Steam From Process	E	45.6	
LP Steam To Process	F	-80.0	
Condensate Heating From Process	G	70.3	
Steam Condensate From Process	H	18.0	
LP Steam To ASU	I	-8.3	

NOTE #1:

Thermal Heat for streams 2-5 is sensible heat above 77 Degrees F per NBS Ideal Gas Thermo Property Tables
 Thermal Heat for streams A-I is sensible heat above liquid water at 32 Degrees F per ASME Steam Tables

NOTE #2:

For streams A-I (steam and boiler feedwater), a negative number reflects energy flow from the combined cycle, while a positive number reflects energy flow to the combined cycle.

TABLE 25-3

POLK COUNTY IGCC - INTEGRATED PLANT PERFORMANCE PROJECTION
 PITT 8 NOC Coal, Expected Gasifier Conditions, 90F Ambient

SPECIFIC CASE RESULTS - POWER SUMMARY (MW)

GROSS POWER			
CT POWER	192.00		
ST POWER	<u>120.58</u>		
GROSS POWER PRODUCTION			312.58 MW
AUXILIARY POWER			
PROCESS PLANT			
ROD MILL	0.42		
CHARGE PUMPS	0.20		
H2SO4 BLOWERS	0.39		
LEAN AMINE PUMP	0.26		
OTHER	<u>1.11</u>		
TOTAL PROCESS		2.38	
ASU			
MAIN AIR	30.75		
MAIN N2	15.31		
MAIN O2	5.72		
N2 SOOTBLOWER	<u>0.85</u>		
TOTAL ASU		52.63	
POWER PLANT			
STEAM CYCLE POWER	3.03		
CT AUX POWER	0.60		
OTHER	<u>0.62</u>		
TOTAL POWER PLANT		4.25	
MISC. AUXILIARIES			
PLANT	3.24		
STATIC LOAD	<u>1.00</u>		
TOTAL MISC. AUXILIARIES		<u>4.24</u>	
TOTAL AUXILIARY POWER			<u>-63.50</u> MW
NET POWER			249.08 MW
NET HEAT RATE BASIS COAL HHV			8775 BTU/KWH

**TAMPA ELECTRIC COMPANY
DOCKET NO. 960409-EI
FPSC STAFF'S 1st SET
INTERROGATORY NO. 5
WITNESS: BLACK
PAGE 1 of 1**

5. Please provide an estimate of the annual value of the IGCC sunk costs that could be salvaged, i.e., selling off equipment, deferring contracts.
- A. Given the fact that our sunk cost estimate significantly understates the actual sunk costs that we would incur, consideration of off setting revenue attributable to the sale of equipment, deferral of contracts and value of salvage would not have the affect of lowering our estimate of sunk costs.

TAMPA ELECTRIC COMPANY
DOCKET NO. 960409-EI
FPSC STAFF'S 1st SET
INTERROGATORY NO. 9
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PAGE 1 of 1

9. On page 5 of 16, in response to Staff's Interrogatory No. 26 in Docket No. 950379-EI, Note 3 states "Capital costs include expenditure of approximately \$4 million in 1997 for plant modifications to burn pet coke blend." Please provide a detailed description of the required plant modifications and costs. Was this expenditure included in the studies provided in response to Staff's Interrogatory No. 3 in Docket No. 950379-EI? If so, please provide the amount and timing of these expenditures assumed for each study.
- A. The \$4 million estimate was included in the 1996 study only for IGCC plant modifications in order to support a petroleum coke/coal blend beginning in 1999 and beyond. The potential plant modifications are in the areas of fuel handling and fluxing of the petroleum coke/coal blends, sulfur removal and recovery sections of the plant, and in the zero discharge wastewater treatment section of the plant. These potential modifications were identified in May, 1995 and therefore were not included in prior studies.

18. What are the individual manufacturer's recommended fuel quality specifications for each individual component of the Polk County IGCC including the gasifier, boiler, hot gas recovery unit and combustion turbine?

A. The controlling fuel specification for the Polk IGCC unit is the fuel requirement for the combustion turbine (CT). Each of the other supporting components that has a specific fuel specification, has a fuel specification that has been developed to support the requirements of the CT.

For Polk Unit One, General Electric (GE) provided both a start-up (#2 oil) and a main fuel (syngas) specification. Document Nos. 18-1 and 18-2, attached to this response are the #2 fuel oil and syngas specification, respectively.

The heat recovery steam generator (HRSG), does not produce or consume a fuel, it removes energy from the exhaust gas of the combustion turbine. As such, there is no fuel specification for the HRSG.

The fuel specification for the auxiliary boiler is the same as the specification for No. 2 fuel oil given in Document No. 18-2.

The gasifier fuel inlet specification utilized as the design basis for the gasifier is given on Document No. 18-3, which is attached to this response.

The gasifier outlet specification, which is the critical requirement for matching the CT fuel specification, is as listed in Document No. 18-4, which is attached to this response.

As noted above, the critical element related to fuel specification for the Polk IGCC is the inlet specification for the CT. It is expected that the gasifier will produce the necessary quality of syngas for the CT with varying qualities of coal and for the Polk IGCC unit specifically, with varying blends of pet coke and coal.

The Texaco gasifier is fully capable of satisfactory operation on many types of inlet fuel. This fact is confirmed by the documentation included in Document No. 18-5, which is attached to this response. This document includes eleven (11) different technical descriptions and references to the fuel flexibility and capability of the Texaco gasification process.

It is this flexibility that provided TEC with the assurance that Texaco could match the GE CT fuel needs with a broad variety of gasifier inlet fuel, including a wide range of coal and coal/pet coke blends.

**TAMPA ELECTRIC COMPANY
DOCKET NO. 960409-EI
SUBMITTED FOR FILING 5/2/96
FPSC STAFF'S 1st SET
INTERROGATORY NO. 18
WITNESS: BLACK**

EXHIBIT NO. ____ (CRB-1)

OF

CHARLES R. BLACK

Document No. 1	Gas Turbine Liquid Fuel Specifications	Page 1 of 22
Document No. 2	Process Specification: Fuel Gases for Combustion In Heavy-Duty Gas Turbines	Page 1 of 10
Document No. 3	Table 2.5: Design & Normal Operating Coal Analyses	Page 1 of 1
Document No. 4	Heat and Material Balance - Pitt 8, Design Case	Page 1 of 1
Document No. 5	Texaco Fuel Flexibility References	Page 1 of 1



GE Industrial & Power Systems
Gas Turbine

Gas Turbine
Liquid Fuel Specifications

TABLE OF CONTENTS

PAGE 2 OF 2

I. GENERAL	3
II. FUEL CLASSIFICATION AND OPERATIONAL CONSIDERATIONS	3
III. FUEL SPECIFICATIONS	3
IV. FUEL HANDLING AND TREATMENT	7
A. True Distillate Fuels	7
B. Ash-Bearing Fuels	7
V. NON-FUEL CONTAMINANTS	8
A. Air-Borne Contaminants	8
B. Water-Borne Contaminants	8
C. Non-Fuel Contaminant Relationships	9
VI. FUEL AND ADDITIVE EVALUATION AND SAMPLING	9
A. Fuel Evaluation Procedure	9
B. Requalification of Fuel: Fuel Changes	9
C. Additive Qualification	9
VII. FUEL DESCRIPTIONS	10
A. True Distillates	10
B. Ash-Bearing Fuels	11
VIII. MEANING OF SPECIFICATION TESTS	12
A. Ash and Trace Metal Contaminants	12
B. Sulfur	13
C. Nitrogen	13
D. Hydrogen	13
E. Carbon Residue	14
F. Water and Sediment	14
G. Filterable Dirt	14
H. Viscosity	14
I. Pour Point	15
J. Fuel Gravity	15
K. Distillation	16
L. Flash Point	16
M. Thermal Stability	16
N. Compatibility	16
O. Cetane Number	17
IX. FUEL ANALYSIS DATA REQUIREMENTS	17
A. Sampling	17
B. Heating Value	18
C. Viscosity	18
D. Carbon Residue	18
E. Trace Metal Analysis	18
F. Wax Content and Wax Melting Point	18

I. GENERAL

PAGE 2 OF 11

This specification is for the several types of liquid fuels suitable for use in the General Electric heavy duty gas turbines with firing temperatures of 1600°F (870°C) or higher. It is intended as a guide for users of these turbines for the procurement, use, and where necessary, treatment of fuels.

The fuel properties specified herein include both those which could affect turbine operation and those additional properties which the turbine user may need to specify for his installation. These latter properties are related to fuel storage and handling and local safety and environmental codes.

All of the fuels covered in this specification shall be hydrocarbon oils free from organic acids and free from excessive amounts of solid, fibrous or other foreign matter likely to make frequent cleaning of suitable filters necessary. The fuels shall be stable over storage and shall be compatible with other fuels with which they could normally be mixed.

Procurement of the fuel to specifications is only the first step to successful heavy duty gas turbine operation. Further steps required of the user are: (a) prevention of contamination before, during, and after delivery, (b) proper design of fuel storage, heating and transfer facilities, (c) proper management of the entire facilities with regard to maintenance procedures and schedules and (d) proper design and operation of any fuel treatment equipment.

In addition to outlining the overall fuel requirements, this specification also defines minimum acceptable air quality standards for turbine inlet air, and water requirements for installations which employ either steam or water injection in their cycles. These have been included since the total contaminants entering the turbine must be considered.

II. FUEL CLASSIFICATION AND OPERATIONAL CONSIDERATIONS

Liquid fuels applicable to heavy duty gas turbines range from petroleum naphthas to residual fuels. Within this range, fuels vary in hydrocarbon composition, physical properties, potential pollutants and trace metal contaminant levels. Since contaminants are a most important consideration in fuel application, the liquid fuels have been divided into two basic classes: true distillates (ash-free) and ash-bearing fuels.

Table 1 summarizes the general types of liquid fuels in these two classes and some operational requirements in gas turbine applications. Refer to Appendix A for common names and characteristics of specific fuels within each general type.

III. FUEL SPECIFICATIONS

The required physical and chemical properties of the four classes of liquid fuels are detailed in Table 2. These properties have been divided into two categories: those required for gas turbine performance (Section 3.1, Table 2) and those which may be limited to meet local environmental codes (Section 3.2, Table 2).

Maximum allowable limits are specified for five critical trace metal contaminants: sodium, potassium, vanadium, lead and calcium. General Electric heavy duty gas turbines will operate at levels higher than those specified in Table 2; however, increased maintenance of hot gas path parts may result. Therefore, it is required that the General Electric Gas Turbine Division be consulted for fuel treatment recommendations when the analysis of the fuel as delivered to the gas turbines exceeds the levels indicated. Fuels outside of the specified limits of certain physical properties may also be used, but General Electric should be consulted for consideration of any impact on the operation of the turbine or fuel treatment system, where required.

The Ash-Bearing Fuels in Table 2 are divided into two types: 1) Crudes and Blended Residual Fuels, and 2) Heavier Residual Fuels. The heavy-duty gas turbine will operate satisfactorily on both types, although fuel treating and heating requirements and stack particulate emission levels will generally be less for the first type (Crudes and Blended Residual Fuels).

Table 1 - Comparison of Liquid Fuels and Some Hardware Requirements

Fuel Type	True Distillates		Ash-Bearing Fuels	
	Light	Heavy Blended Residual Fuels	Crudes and Blended Residual Fuels	Heavier Residual Fuels
General Properties Ash Content Viscosity Volatility	Trace Low High/Medium	Trace Medium Medium	Low/Medium Wide Range Wide Range	High High Low
Nearest ASTM Type* Gas Turb., D2880 Burner, D396 Diesel, D975	0-GT, 1-GT 2-GT 1, 2 1-D, 2-D	3-GT (4) (4-D)	3-GT 4, 5 4-D	4-GT 6 —
Explosion-Proofing	Refer to applicable codes	Refer to applicable codes	Refer to applicable codes	Refer to applicable codes
Start-Up Fuel Required	With very light fuels	Some fuels	Nearly always	Always
Fuel Pretreatment	Usually none	Usually none	Nearly always	Always
Fuel Preheating	Some in cold locations	Nearly always	Nearly always	Always
Fuel Filtration	Always	Always	Always	Always
Fuel Combustion Atomization	Low pressure air	Low pressure air	Low or high pressure air	High pressure air
Combustor	Standard fuel	Standard fuel	Heavy fuel	Heavy fuel
Turbine Cleaning Capability	Not Required	Not Required	Required	Required

* Book of ASTM Standards, parts 23 and 24

Note: The considerations listed in this table are not all-inclusive.

Table 2 - Liquid Fuel Specifications

Appli- cability	Property	Point of Applica- bility (a)	ASTM Test Method (c)	True Distillates (b)		Ash-Bearing Fuels (b)	
				Light	Heavy	Crudes and Blended Residual Fuels	Heavier Residu- al Fuels
3.1 Gas Turbine Require- ments	Kin. Viscosity, cSt, 100°F (37.8°C), min	Delivery	D445	.5(d)	1.8	1.8	1.8
	Kin. Viscosity, cSt, 100°F (37.8°C), max (e)	Delivery	D445	5.8	30	160	900
	Kin. Viscosity, cSt, 210°F (98.9°C), max (e)	Delivery	D445	—	4	13	30
	Specific Gravity, 60°F (15.6°C), max	Delivery	D1298	Report	Report	.96	.96(f)
	Flash Point, °F(°C), min (g)	Delivery	D93	Report	Report	Report	Report
	Distillation Temp. 90% Point, °F(°C), max	Delivery	D86	650(338)	Report	—	—
	Pour Point, °F(°C), max	Delivery	D97	0 (-18) or 20 (7) below min. ambient	Report	Report	Report
	Hydrogen, Wt. %, min (k)	Delivery	(i)	Report	Report	Report	Report
	Carbon Residue, Wt. % (10% Bottoms) max Direct Pressure Atomization	Delivery	D524	.25	—	—	—
	Carbon Residue, Wt. % (100% Sample) max Air Atomization, Low Pressure	Delivery	D524	1.0	1.0	1.0	—
	Carbon Residue, Wt. % (100% Sample), Air Atomization, High Pressure	Delivery	D524	—	—	Report	Report
	Ash, ppm, max	Combustor	D482	50	50	Report	Report
	Trace Metal Contaminants, ppm, max (h)	Combustor	(i)				
	Sodium plus Potassium			1	1	1	1
	Lead			1	1	1	1
	Vanadium (untreated)			.5	.5	.5	.5
	Vanadium (treated 3/1 wt. ratio Mg/V)			—	—	100	500
	Calcium			2	2	10	10
	Other Trace Metals above 5 ppm			Report	Report	Report	Report
The specifications below apply only when specific environmental codes exist							
3.2 En- viron- mental Code Related Require- ments	Sulfur, Wt. %, max	Delivery	D129	Compliance to any applicable codes. Fuel-bound nitrogen may be limited to meet any applicable codes on total NO _x emission. Minimum hydrogen level may be necessary to meet any applicable stack plume opacity limits (k). Ash plus vanadium content of ash-bearing fuels may be limited to meet applicable stack particulate emission codes (l).			
	Nitrogen, Wt. %, max	Delivery	(i)				
	Hydrogen, Wt. %, min.	Delivery	(i)				
	Ash plus Vanadium, ppm, max.	Delivery	(i)				

NOTES TO TABLE 2

- a. The fuel properties specified refer to the fuel at different points in the overall system:
 Delivery — Fuel as delivered to the turbine site.
 Fuel Skid — Fuel at inlet of fuel skid at turbine.
 Combustor — Fuel at turbine combustors.
- b. Typical fuels within each general type are discussed in Appendix A.
- c. ASTM Book of Standards, Parts 23 and 24.
- d. In the viscosity range of 0.5 cSt to 1.8 cSt, special fuel pumping equipment may be required.
- e. The maximum allowable viscosity at the fuel nozzle is 20 cSt for high pressure air atomization and 10 cSt for low pressure air and direct pressure atomization. The fuel may have to be preheated to reach this viscosity, but in no instance shall it be heated above 275°F (135°C). (This maximum fuel temperature of 275°F is allowed only with residual fuels.) The viscosity of the fuel at initial light-off must be at or below 10 cSt.
- f. A specific gravity of 0.96 is based on average fuel desalting capability with standard washing systems. Fuels with specific gravities greater than 0.96 may be desalted to the required minimum sodium plus potassium limits by using higher capability desalting equipment (with higher attendant cost) or by increasing the gravity difference between the fuel and wash water by blending the fuel with a compatible distillate.
- g. The fuel must comply to all applicable codes for flash point.
- h. A total ash less than 3 ppm is acceptable in place of trace metal analysis.
- i. No standard reference tests exist; methods used should be mutually acceptable to General Electric and the user.
- j. Water content of crude oils should be reduced to the lowest level practical consistent with capability of available fuel treatment equipment, to minimize the chance of corrosion of fuel system components. In no case shall the water content exceed 1.0 vol. %.
- k. A minimum hydrogen content is set both to control flame radiation in the combustor and to limit smoke emissions, where the latter is required by local codes. The limits are 12.0% minimum for true distillates and 11.0% for Ash-bearing fuels (11.3% where the carbon residue exceeds 3.5%). In each case it is assumed that the proper combustor and fuel atomization system are used.

Where the hydrogen content of the fuel is below these limits, General Electric should be consulted for appropriate action.

- l. Local codes on total stack particulate emissions may set an upper limit on the sum of the ash (non-filterable) in the original fuel plus the vanadium content. The vanadium together with the required magnesium inhibitor may be a major contributor to total stack particulate emissions. In estimating these emissions for comparison with the code, all of the following sources may have to be considered: vanadium, additives, fuel ash and total sulfur in the fuel; non-combustible particulates in the inlet air; solids from any injected steam or water; and particles from incomplete fuel combustion. Where an estimate of stack particulate emissions is required, General Electric should be consulted.

IV. FUEL HANDLING AND TREATMENT

A. True Distillate Fuels

Light true distillate fuels normally have sufficiently low pour points that preheating is not required under most ambient conditions. Heavy true distillates, on the other hand, may have high pour points due to high wax content or high wax melting temperature which make preheating necessary to prevent filter plugging. Both types of distillates may also require preheating to meet the viscosity requirement at the fuel nozzle for proper atomization.

True distillate fuels as refined have low water, dirt and trace metal contaminant levels. Where subsequent transportation, handling and storage are carefully managed, these low levels should persist at the gas turbine. In locations where there is danger of contamination such as salt bearing water, auxiliary fuel clean-up equipment should be provided to restore the original quality.

In addition to potential hot corrosion from salt in water, water accumulated at the bottom of a storage tank can also cause problems. Micro-organisms tend to grow at the water-fuel interface generating both chemicals corrosive to metals in the fuel system and also slime which can plug fuel filters.

Adequate fuel storage and handling practices must be employed to minimize water and other contaminants in the fuel. These include settling the fuel before use, providing floating suction and periodic removal of water from the bottom of the tank. In applications where adequate settling periods can not be accommodated, more rapid purification methods may be required. Available purification equipment includes centrifuges and electrostatic dehydrators. The overall fuel system design should avoid slugs of water, and any clean-up system should have the capability to remove such slugs.

B. Ash-Bearing Fuels

Depending on the physical properties and the trace metal contaminant levels of these fuels, functions of the source and refinery treatment, they usually require pretreatment before burning in a gas turbine. Three basic steps in pretreatment are:

1. Preheating
2. Water washing for salt removal
3. Vanadium inhibitor addition

Preheating is used where it is necessary to: 1) raise the fuel temperature sufficiently above its pour point to allow free flow and to prevent filter plugging, and 2) to lower the fuel viscosity to reduce the flow resistance and to provide proper atomization at the fuel nozzles.

Desalting by water washing will be necessary with some crude oils and is nearly always necessary with residual oils to reduce the sodium plus potassium levels. Sodium and potassium can cause hot corrosion of the turbine blading by sulfidation attack at the operating temperatures of the turbine. Sodium and potassium can also contribute to turbine fouling. Desalting is accomplished by mixing the fuel with 3% to 10% potable water to extract the soluble salts, followed by separation of the salt-laden water by centrifugation or electrostatic coalescence. Washing also removes some of the calcium depending on the specific chemical nature of the calcium compounds. Lead is not removed by water washing.

Vanadium can also cause hot corrosion of the turbine blading, but it is not removed by water washing because it is present in the fuel in a complex oil-soluble form. The corrosive action can be inhibited by adding an approved magnesium additive to the fuel to provide a minimum 3 to 1 weight ratio of magnesium to vanadium. It is also recommended that this ratio not exceed 3.5 to 1 in order to minimize deposition.

Periodic cleaning of deposits from turbine hot gas path section is generally necessary when high ash content fuels are used. Cyclic operation of the turbine may remove some the deposit by thermal shock. General Electric should be consulted for approved cleaning agents, water quality and cleaning procedures for those applications where turbine cleaning is required.

V. NON-FUEL CONTAMINANTS

A. Air-Borne Contaminants

Contaminants in air can cause erosion, corrosion and fouling of the compressor. These contaminants can also contain the same trace metals as found in fuels and which cause corrosion to the hot section.

Compressor erosion can be caused by sand or flyash; compressor corrosion by noxious fumes such as HCl or H_2SO_4 ; compressor fouling by liquid or solid particles which adhere to the compressor blading. Hot section corrosion can be caused by sodium from, e.g., sea salt, salt particles, carry-over of treatment chemicals used in evaporative coolers, chemical process effluents; potassium from flyash or fertilizers; lead from automobile exhausts; and vanadium from residual fuel fired steam plants.

Specifically, with respect to hot section corrosion, the total of Na, K, V and Pb should not exceed 0.005 ppm by weight in air. If it is anticipated that this level will be exceeded, General Electric should be consulted for recommendations on the selection and use of proper air filtration equipment.

B. Water-Borne Contaminants

Water or steam that is used for NO_x control or steam that is injected to augment output should not contain impurities which cause hot section deterioration or deposits. Specifically, the total of Na + K + V + Pb should not exceed 0.5 ppm by weight in the water or steam. If the total of these contaminants exceeds this level, General Electric should be consulted with respect to water or steam purification equipment and procedures.

In the case where contaminants are present in water or steam the total limits in the fuel should be controlled such that the total concentration equivalent in the fuel (from both sources) conforms to the limits in Table 2.

Refer to the next section 5.3 for the method for calculating the equivalent concentration in the fuel.

C. Non-Fuel Contaminant Relationships

The total contaminant level in the combustion products must be controlled. The following relationship can be used to convert the contaminants in air, steam/water and fuel to equivalent contaminants in the fuel alone, assuming all are equally effective:

$$\left(\frac{A}{F}\right) X_A + \left(\frac{S}{F}\right) X_S + X_F = \{ \text{Equivalent contaminants in fuel alone} \}$$

where:

$\frac{A}{F}$ = air-to-fuel mass flow ratio

$\frac{S}{F}$ = steam/water-to-fuel mass flow ratio

X_F = contaminant concentration (weight) in fuel (ppm)

X_A = contaminant concentration (weight) in inlet air (ppm)

X_S = contaminant concentration (weight) in injected steam/water (ppm)

VI. FUEL AND ADDITIVE EVALUATION AND SAMPLING

A. Fuel Evaluation Procedure

A supplier's fuel analysis shall be submitted to the General Electric Gas Turbine Division covering all the fuel requirements outlined in Table 2 of this specification. If the required analytical services are not available to the user, he may make arrangements to purchase such services from General Electric. See Appendix C for fuel sampling and analysis requirements.

B. Requalification of Fuel: Fuel Changes

The fuel properties outlined in the specification and originally agreed upon by General Electric Company and the user will determine some of the equipment selection and certain operating conditions of the gas turbine system. If at a later date the user desires to use a fuel outside of the original agreed-upon limits, he should inform the General Electric Company in writing. He should supply a complete analysis for evaluation and requalification in a similar manner as outlined above.

C. Additive Qualification

Additives used in gas turbine fuels such as vanadium inhibitors, desalting demulsifiers, bacterial growth retardants or smoke suppressants must meet the approval of the General Electric Gas Turbine Division. One critical requirement of an additive is that it has a low trace metal content (sodium, potassium, vanadium, calcium and lead), so that the inhibitor does not add these contaminants to the fuel.

VII. FUEL DESCRIPTIONS

A. True Distillates

1. Light True Distillates

Naphtha - A light volatile fuel with a boiling range between gasoline and Light Distillate. The lower flash point and higher volatility require special safety considerations. Its very low viscosity may result in poor lubricity.

Other Names:

JP-4, Jet B

O-GI Gas Turbine Fuel

PAGE 10 OF 11

Kerosene - A light, highly refined and slightly more volatile fuel than Light Distillate. Normally more expensive than No. 2 distillate.

Other Names:

1-GT Gas Turbine Fuel

No. 1 Burner Fuel

1-D Diesel Fuel

JP-5, Jet A

Range Oil, Lamp Oil

Light Distillate - Widely available volatile distillate fuel with good combustion characteristics, being readily atomized and clean burning.

Other Names:

2-GT Gas Turbine Fuel

No. 2 Burner Fuel

Diesel Oil

Marine Gas Oil

Domestic Fuel

Diesel Fuel - Closely related to Light Distillate fuel except for additional requirements peculiar to diesel engine operation such as Cetane Number.

Other Names:

2-D Diesel Fuel

2. Heavy True Distillate

An essentially ash-free petroleum distillate with the highest boiling range. Heavy True Distillate has had limited and localized availability, frequently being a refinery by-product. This fuel may require heating for handling and forwarding due to high pour point. It may also be more difficult to atomize for optimum combustion.

Other Names:

Heavy Gas Oil

Navy Standard Distillate

B. Ash-Bearing Fuels

1. Crudes and Blended Residual Fuels

Crudes - Crude oils from different geographical areas vary widely in levels of trace metal contaminants, ash, sulfur and wax and in such physical properties as viscosity, gravity and distillation range. Most crudes will have flash points below 100°F (38°C) due to highly volatile components. Some very low ash crudes, typified by Indonesian and North African crudes, have 0 to 5 ppm of vanadium requiring minimal or no inhibition. Other crudes for gas turbine application range up to 100 ppm vanadium. Most crudes require desalting, especially if water transportation has been used.

Blended Heavy Distillate - Petroleum distillate contaminated with or blended with lesser amounts of residual petroleum products, but with vanadium contents of 5 ppm or less. They may have wax contents requiring heating for pumping and filtering. They may also require washing for desalting, especially if water transportation has been used.

Other Names:

- 3-GT Gas Turbine Fuel
- 4-D Diesel Fuel
- Marine Diesel Fuel

Blended Residuals - Blended residuals lie between blended heavy distillates and heavy residuals. They are commonly blended to specific maximum sulfur levels to meet applicable codes. Vanadium contents are in the 5 ppm to 100 ppm range normally. These fuels require complete fuel treatment.

Other Names:

- No. 4 Burner Fuel
- No. 5 Burner Fuel
- Light Residual Oil
- Light Furnace Oil
- Intermediate Bunker Fuel

2. Heavier Residual Fuels

Residual Fuels - These are low volatility petroleum products remaining at the end of all various refinery distillation processes. As such they contain nearly all of the ash-forming materials present in the original crude oil plus some additional that may be introduced in processing. They usually contain high molecular weight hydrocarbons such as asphaltenes, which can cause storage sludging problems. Residual fuels may have been blended with low cost distillates to lower the sulfur content and/or reduce the viscosity to insure pumpability.

All residual fuels require heating for pumping, filtering and proper air atomization at the fuel nozzle. Residual fuels all require washing to reduce the sodium level and vanadium inhibition by addition of a General Electric approved Magnesium base additive.

Other Names:

- No. 6 Burner Fuel
- Boiler Fuel
- Bunker C. Fuel
- Marine Fuel Oil

VIII. MEANING OF SPECIFICATION TESTS

Chemical tests are specified because slag-forming substances present in oil ash can cause turbine corrosion and deposits, and the presence of sulfur can result in corrosion of heat recovery equipment in the turbine exhaust. Certain physical tests are specified because they influence the operation of the gas turbine fuel handling, fuel treatment and combustion systems.

A. Ash and Trace Metal Contaminants

PAGE 12

Ash-forming materials may be present in a fuel as oil-soluble organometallic compounds, as water soluble salts in water dispersed in the fuel or as solid foreign contaminants. The most common ash-forming elements which can be present in fuels are aluminum, calcium, iron, magnesium, nickel, potassium, sodium, silicon and vanadium. Ash-forming materials are present to varying degrees in crude oils depending on their geographical source. They are concentrated in the residual fractions during the refining process, leaving the light distillates contaminant-free; however, ash-forming materials may be introduced later by contamination with salt-bearing water or with other petroleum products during transportation and storage.

Gas turbine operating experience has shown that some of the ash-forming substances that may be present in the fuel can lead to corrosion and deposit problems. These problems are most acute with residual and crude oils which contain larger quantities of the troublesome substances.

Corrosion can result from (1) vanadium, (2) sodium, (3) potassium or (4) lead. These elements as well as calcium (and others such as magnesium, manganese, iron, silicon and aluminum) can cause ash deposits which are difficult to remove. Calcium can act as an effective inhibitor for vanadium corrosion, but its deposition tendencies have precluded its use.

In light distillate fuels, the total ash content is usually very small, and trace metal contamination is essentially a sodium (salt) problem. There are also usually traces of lead and calcium and smaller traces of potassium and vanadium. It is advantageous to purchase fuel within the specified contaminant limits and to maintain this quality during transportation, handling and storage. On-site desalting by contaminated water removal or by fuel washing of distillate fuels with relatively high sodium levels is required to keep corrosion of the hot gas path and the fuel system components such as flow dividers and fuel pumps at a very minimum level.

Crudes and contaminated distillates almost without exception have high enough salt levels, or the risk of significant salt levels, that they require desalting. The vanadium levels may also be significant and require the addition of a magnesium-base inhibitor to establish a ratio of 3 parts of magnesium to 1 part of vanadium by weight.

Residual fuels have the highest ash and trace metal contaminant levels usually necessitating complete fuel pretreatment: desalting and vanadium inhibition by a magnesium-based additive (3Mg/1V). Due to the less favorable physical properties of residual fuels, it is not possible to consistently reduce the sodium to the low levels obtainable in light crudes and distillates. The higher sodium levels in treated residual fuels result in controlled corrosion and deposit accumulation with some increase in maintenance. Calcium levels may be high in some residual fuels, but they may be appreciably lowered by the fuel treatment. Nickel, which is not removed by fuel treatment, may also be high in certain residual fuels and is somewhat beneficial in that it tends to neutralize vanadium corrosion in much the manner of magnesium. Residual fuels contain harmless aluminum, iron and silica as components of suspended solids (dirt). A significant portion of these suspended particles are removed either in the fuel washing or by fuel filtration.

B. Sulfur

Sulfur occurs in fuels as combustible organic compounds yielding sulfur oxides on combustion. These combine with any traces of sodium or potassium present to form alkali sulfates; a principal source of hot corrosion. The sulfur level in a fuel cannot be lowered enough by refining to avoid the formation of alkali sulfates, so that they must be controlled by limiting the sodium and potassium levels in the fuel.

Gas turbine installations utilizing exhaust heat recovery equipment could have metal temperatures below the dewpoint of sulfuric acid, and in these cases it is necessary to know the sulfur level in the fuel to avoid acid corrosion of heat transfer surfaces. The maximum allowable sulfur to avoid sulfuric acid condensation will depend on the specific heat recovery equipment used. For fuels exceeding this maximum level, the operating temperature of the heat recovery equipment could be changed accordingly to avoid condensation of acid products.

The sulfur level of liquid fuels is regulated in many localities as a means of controlling the emission of sulfur oxides in the exhaust gases.

Crude oils burned directly as fuels may also contain active sulfur in the form of hydrogen sulfide or mercaptans. These substances, especially in the presence of water, may cause corrosion to fuel system components. For this reason, the water content of such fuels should be kept as low as possible.

C. Nitrogen

Fuel-bound nitrogen in petroleum fuels comes largely from organo-nitrogen compounds present in the original crude oil. In some distillate fuels, fuel-bound nitrogen may also come from additives such as stabilizers.

This chemically-bound nitrogen in the fuel will contribute to the total nitrogen oxide pollutant in the exhaust gases, adding to the nitrogen oxides from the direct combination of atmospheric nitrogen and oxygen in the gas turbine combustion reaction. The particular combustion system and operating conditions will affect the total nitrogen oxide production from both atmospheric and fuel-bound nitrogen.

D. Hydrogen

The percent combined hydrogen in a hydrocarbon fuel is a critical factor in controlling stack smoke levels. In general, the higher the hydrogen content in a liquid fuel the lower the smoke level will be. As an example: paraffinic hydrocarbons with high hydrogen contents (14-15%) have much less tendency to smoke than do aromatic hydrocarbons which can have 10% or less hydrogen.

Hydrogen is usually determined by an accurate measurement of the amount of water produced in the controlled combustion of a weighed amount of fuel.

E. Carbon Residue

Carbon residue is measured as the residue remaining when a fuel sample is completely distilled in a standard apparatus. To obtain measurable residue with light distillates, the fuel is first distilled to remove 90% (ASTM Method D86) by volume, and then the carbon residue is determined on the "10% Bottoms."

One effect of a high carbon residue is carbon formation near the fuel nozzle. To control this, air atomization is used in the combustion of all but the lightest fuels, high pressure air being required for the heaviest fuels.

F. Water and Sediment

Water and sediment in a fuel oil tend to cause fouling of the fuel handling facilities and the gas turbine fuel system. Accordingly they should be kept at as low a value as practicable and always within the maximum values shown in this specification.

The sediment in fuel can be gums, resins, asphaltic materials, carbon, scale, sand or mud. It is mainly a problem in residual fuels. Very few distillate fuels leave the refinery with more than 0.05% water and sediment. However, poor handling practices can unnecessarily raise this level, and once an oil becomes contaminated it may not be feasible to restore its original cleanliness, such as the case of lead or vanadium contamination.

Gas turbines are normally equipped with high capacity 5 micron filters. Since there are practical limits to the efficiency of filtration systems, a fraction of the solids entering the filter remains in the oil and can be an important factor in fuel system component life.

Fuel storage tanks should be designed with floating suctions that are equipped with low level bottom limits to insure that the suction is always some distance from the bottom to avoid the water and sediment that collects there. The operator should drain the bottom of the tank periodically to reduce the accumulation and the risk of contamination. Automatic water drainage systems are preferred.

G. Filterable Dirt

Filterable dirt is essentially the suspended solid particulate matter in a distillate fuel which can cause fuel filter maintenance problems. It is measured as the weight of solids held on a low porosity filter during the filtration of a given volume of fuel.

H. Viscosity

The viscosity of fuel is a measure of its resistance to flow. It is important in the fuel auxiliary equipment since it determines pumping temperature, atomizing temperature and oil pump pressure.

In order to obtain proper operation of the gas turbine, the maximum viscosity at the fuel nozzles must not exceed 10 centistokes for pressure atomizing or low-pressure air-atomization fuel systems, and 20 centistokes for high-pressure air-atomizing systems. When these limits are exceeded, poor ignition characteristics, smoking, unsatisfactory combustor exit temperature distribution, lowered combustion efficiency or formation of carbon may occur. In most cases, fuel heating must be employed to insure that these viscosity limits at the fuel nozzle are met under all ambient conditions. In all cases the fuel at initial light-off must be at or below 10 cSt viscosity.

Minimum viscosity limits are imposed to safeguard the high pressure fuel pump, which depends on the lubricating qualities of the fuel for satisfactory operation. It should be noted that naphtha fuel can have a minimum viscosity as low as 0.5 cSt at 100°F (37.3 °C).

Special pumps may be required for viscosities below 1.8 cSt at 100 °F.

I. Pour Point

The pour point of a fuel is the temperature at which it will barely flow under standard conditions, and it is significant in connection with fuels that may require heating to make them pumpable and with fuels fed to a pump by gravity flow.

Petroleum oils when cooled may change to a plastic state as a result of partial separation of wax (wax pour) or by congealing of hydrocarbons (viscous pour) comprising the oil.

A waxy fuel must be maintained at a high enough temperature to ensure that all of the wax is in solution to prevent wax crystals from clogging filters and lines. For distillates, wax separation can usually be avoided by heating the fuel to at least 20-30°F (11-17°C) above the pour point. Waxy crude oils used as fuels may require even higher temperature differentials. Each type of waxy fuel must be evaluated individually for minimum wax solution temperature. (For methods, refer to page C2.)

J. Fuel Gravity

The specific gravity is not a critical property of gas turbine fuels. Within a given fuel type it can indicate the chemical composition of the hydrocarbons. As an example, a distillate with a low specific gravity will be largely paraffinic whereas a high specific gravity will be more aromatic. The latter would have a greater tendency to smoke with other factors being equal.

Gravity can have an economic significance where the fuel is purchased by volume since the total heat units will decrease with decreasing specific gravity.

Residual fuels requiring washing will be more difficult to wash if the specific gravity approaches that of water.

In the petroleum industry it is customary to use API gravity instead of specific gravity for convenience since the API system eliminates the small decimal difference between fuel samples encountered in the use of specific gravity. It is always referenced to 60°F (15.6°C).

$$API = \left[\frac{141.5}{\text{Spec. Grav.}} \right] - 131.5$$

Some typical examples are:

	Specific Gravity	API Gravity
Water	1.00	10.0
Kerosene	0.78-0.83	50-39
No. 2 Distillate	0.82-0.86	41-33
Crudes and Blends	0.80-0.92	45-22
Residual Oils	0.92-1.05	22-3

K. Distillation

The heavy duty gas turbine is not sensitive to the distillation characteristics of the fuel per se.

Extremely volatile fuels such as naphthas require the use of a start-up fuel (light distillate) due to the low temperature at which they vaporize, giving the possibility of combustible vapors in the fuel lines.

Very high end-point fuels, approximately 1000°F (538°C), can have excessive traces of vanadium which have distilled over. For this reason pure distillate usually would have a maximum end point specification. (This is also prevented by setting a maximum vanadium level.)

L. Flash Point

PAGE 11 OF 25

The flash point of a fuel is the temperature at which fuel vapors will flash when ignited by an external flame.

The flash point is regulated for safety in fuel handling and storage. By itself it is not critical to turbine operation although it can affect the requirements for auxiliary equipment such as motors, relays, heaters, etc.

Minimum permissible flash points are regulated by local, state or federal laws.

Explosion-proofing of equipment may be required by local, state or federal regulations or other applicable codes when the flash point is below a minimum permissible value.

M. Thermal Stability

The thermal stability of an oil is a measure of its ability to resist breaking down when heated to form deposits of resins and sludge. This can occur in the fuel nozzle area and in fuel heaters especially if the heater surface is far hotter than the surrounding oil. This polymerization to form deposits is a time-temperature phenomenon: being accelerated by high temperatures, long exposure times and contact with air.

Thermal stability is most critical for high viscosity residual fuels which require high temperatures to meet fuel atomization viscosity requirements. The maximum allowable temperature specified is 275°F (135°C).

N. Compatibility

Mixing certain residual type fuels with dissimilar residual fuels or diluting residual type fuels with certain distillates may result in the formation of tarry precipitates. The precipitation may occur immediately after mixing or may take some time to develop. Heating for prolonged periods of time will generally accelerate the separation.

This tarry residue can accumulate in the bottom of tanks and can settle out in fuel lines and on filters.

When the separation of residue occurs, it is usually in those residual fuels which have a heavy asphaltene fraction present as a colloidal metastable gel; such as those which have had an intensive heating history during refining. The nature of a solvent used for dilution (blending) is also important: paraffinic (low specific gravity) distillates are more apt to cause precipitation than aromatic (high specific gravity) distillates.

One method of testing for compatibility is to make a 50-50 mixture of two oils and then subjecting the mixture to a thermal stability test. A simple screening test is the ASTM D2781, "Compatibility of Fuel Oil Blends by Spot Test."

ASTM Specifications do not specify this property, again because it has not been the practice of the oil suppliers to make this test. These specifications do not call for the test on the light distillate oils because it is very rare that they encounter compatibility difficulties with one another. However, for the heavier oils, it is necessary to start up and shut down the gas turbine on a light distillate oil; therefore, it is advisable to test the compatibility of the heavy oil/distillate mixture.

O. Cetane Number

Cetane number is an index of the burning quality of fuel in a diesel engine. It is specified only when the turbine fuel is also used in a diesel starting engine.

Cetane number is most accurately measured in a special test engine, but a reasonably accurate value can be obtained from a correlation between the specific gravity and the 50% distillation point.

IX. FUEL ANALYSIS DATA REQUIREMENTS

To evaluate a liquid fuel for gas turbine application certain physical and chemical data are required. Basic specification requirements are given in Table 2, Section 3. Certain other data are needed for engineering purposes. Table 3 is a list of required data. Following is pertinent information on some of the analytical tests.

A. Sampling

Since analyses of small traces of metals are involved, and since some tests use small amounts of sample, it is very important that the fuel sample is uniform and representative of the fuel as received by the user or shipped by the supplier. If the fuel is taken from a container, it should be thoroughly mixed mechanically before sampling. For sampling from storage tanks, refer to ASTM Standard Method for Sampling Petroleum Products, D-270-65.

The sample for analysis should be stored preferably in plastic or plastic-lined metal containers. Avoid metal cans with soldered seams and containers with seals (rubber) which can disintegrate and contaminate the fuel. The container should only be about two-thirds full so that it may be well shaken before taking analytical samples. Heavy residual fuels should be in wide-mouth containers.

B. Heating Value

The heating value measured is the High (Gross) Heating Value, where the water produced is condensed. The Low (Net) Heating Value is obtained by calculation from the Higher Heating Value by one of several methods including ASTM D 1405 and D240. The latter requires an accurate value for percent hydrogen while the former requires an aniline point (ASTM D1012) and specific gravity.

C. Viscosity

Viscosities at two temperatures are needed for a viscosity-temperature relationship for the fuel; the two temperatures normally being 100°F (37.9°C) and 210°F (98.9°C). If the pour point is between 70°F (21°C) and 90°F (32°C), the lower temperature should be 122°F (50.0°C). For pour points between 90°F (32°C) and 120°F (49°C), the lower temperature should be 150°F (65.6°C).

D. Carbon Residue

Ramsbottom carbon residue (ASTM D524) is preferred as more accurate. If the Conradson method (ASTM D189) is used, the results should be converted to Ramsbottom (see D524).

E. Trace Metal Analysis

Trace metal contaminant levels are usually measured by spectrometric methods such as atomic absorption, flame emission or a spark source spectrometry. The first two methods use a solvent diluted fuel sample while the latter operates directly on the original fuel. In any case, the reference standards must match the fuel properties as closely as possible. For very accurate analyses of vanadium and lead, it is better to ash the fuel and run the spectrometric analysis on an aqueous solution of the treated ash. In the ashing procedure, special care must be taken not to lose these elements.

F. Wax Content and Wax Melting Point

Crude oils and heavy true distillates should be tested to determine the minimum fuel temperature required to keep all of the wax in solution.

One approach is to remove the wax from the fuel and then to determine its melting point, which represents the maximum solution temperature. There is no standard method for wax separation, but there are several laboratory procedures which are satisfactory. They all involve dilution of the fuel with a poor wax solvent and then chilling to 0°F (-18°C) or lower to separate the wax crystals which are filtered out at low temperature.

An instrumental procedure which measures the wax solution temperature directly on the fuel is Differential Scanning Calorimetry (DSC). This method is still being developed and has not yet been successful with all crude oils.

For light distillate fuels, ASTM D 2500 Cloud Point or ASTM D3117 Wax Appearance Point may be used.

Table 3 – Fuel Analysis Data

PAGE 10 OF 11

Property	ASTM Method (1)	Measured Value
Gross Heating Value, Btu/lb	D240	_____
Kin. Viscosity, cSt, 100°F (37.8°C)	D445	_____
Kin. Viscosity, cSt, 122°F (50.0°C)	D445	_____
Kin. Viscosity, cSt, 210°F (98.9°C)	D445	_____
Specific Gravity, 60°F (15.6°C)	D1298	_____
Specific Gravity, 100°F (37.8°C)	D1298	_____
Pour Point, °F(°C)	D97	_____
Flash Point, °F(°C)	D98	_____
Distillation Range (Not on Residuals)	D86	_____
		IBP _____ °
		10% _____ °
		20% _____ °
		30% _____ °
		40% _____ °
		50% _____ °
		60% _____ °
		70% _____ °
		80% _____ °
		90% _____ °
		EP _____ °
Carbon Residue, Wt. %	D524	_____
Sulfur, Wt. % (Very Light Distillates)	D1266	_____
Sulfur, Wt. % (All Other Fuels)	D129	_____
Hydrogen, Wt. %		_____
Nitrogen, Wt. %		_____
Total Ash (2), ppm	D482	_____

Table 3 – Fuel Analysis Data (Cont'd)

PAGE 11 OF 11

Trace Metals, ppm (2)

Sodium

Potassium

Vanadium

Calcium

Lead

Other Metals Over 5 ppm

Sediment & Water Vol. %

D1796

Water, Vol. %

D95

Filterable Dirt, mg/100ml

D2276

Wax, Wt. %

Wax, Melting Point, °F

Cetane No. (Diesel Engine Start Only)

D975

(1) Book of ASTM Standards, Part 17

(2) A total ash less than 3 ppm is acceptable in place of trace metal analysis

(3) Wax data only on crudes and heavy distillates

PAGE 1 OF 1
PAGE 1 OF 1

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**GE Industrial & Power Systems**
Gas Turbine

PAGE 1 OF 10

Process Specification

Fuel Gases For Combustion In Heavy-Duty Gas Turbines

I. GENERAL

G.E. heavy-duty gas turbines are burning a wide range of gaseous fuels as shown in Table 1. These gases present a broad spectrum of properties due to both active and inert components along with their contaminants. This specification is designed to define concerns which need to be considered to burn these fuels in a trouble-free manner in GE heavy duty gas turbines.

Table 2 gives test methods for determining gas properties. Table 3 gives the limits on fuel properties and contaminants for successful gas turbine operation.

TABLE 1 FUEL GAS CLASSIFICATION		
FUEL	LHV Btu/SCF	MAJOR COMPONENTS
Natural Gas	800-1200	Methane
Liquefied Petroleum Gas (LPG)	2300-3200	Propane, Butane
Process Gases	300-1000	Methane, Hydrogen, Carbon monoxide, Carbon dioxide
Gasification Gases		
air blown	100-150	Carbon monoxide, Hydrogen, Nitrogen
oxygen blown	200-400	Carbon monoxide, Hydrogen

TABLE 2
TEST METHODS FOR GASEOUS FUELS

PROPERTY	ASTM METHOD
Gas Composition (gas chromatography)	D 1945
Heating Value	D 3588
Specific Gravity	D 3588
Compressibility Factor	D 3588
Dew Point	D 1142
Sulfur	D 3246

TABLE 3
GAS FUEL SPECIFICATION

Heating Value	
Minimum LHV (Note 1)	100-300 Btu/SCF
Wobbe Index variation	
start up	± 5%.
above FSNL (full speed no load)	(Note 2)
Superheat Required	>50°F (28°C) above hydrocarbon/water dewpoint
Flammability Limit Ratio	>2.2/1 (rich-to-lean, volume basis)
Contaminants	

Trace Metals (Note 3)	Turbine Inlet Limit (XE) (ppbw)	Fuel Limit (XF _e) (ppmw)			
Turbine inlet flow/fuel flow, (E/F)			50	12	4
Lead (Pb)	20	1.00	.240	.080	
Vanadium(V)	10	.50	.120	.040	
Sodium + Potassium: (Na/K)=28 (Note 3)	20	1.00	.240	.080	
(Na/K)=3	10	.50	.120	.040	
(Na/K)=<1	6	.30	.072	.024	
Calcium (Ca)	40	2.0	.480	.160	
Magnesium (Mg)	40	2.0	.480	.160	
Particulates					
Total	600	30	7.2	2.4	
Above 10 microns	6	0.3	.072	.024	
Sulfur (Note 4)	600	30	7.2	2.4	

Note 1: LHV depends on composition. Contact Project Engineering for particular fuels.

Note 2: See Section on Fuel Properties, under Heating Values. For DLN (Dry Low NO_x) see Appendix 1.

Note 3: See Appendix 2 for definitions and calculations of trace metal limits.

Na/K=28 is nominal sea salt ratio.

Note 4: Applies to units having an HRSG (Heat Recovery Steam Generator) only.

Report if SCR (Selective Catalytic Reduction) is present.

II. NATURAL AND PETROLEUM GAS

page 3 of 10

Under this category we will include the fuel gases usually called natural gas and liquefied petroleum gases (LPG). Natural gases are predominantly methane with much smaller amounts of the slightly heavier hydrocarbons such as ethane, propane and butane. LPG is a mixture of propane and butane with traces of heavier hydrocarbons.

A. Natural Gas:

Natural gases normally fall in the calorific heating value range of 800 to 1200 Btu per standard cubic foot depending on the percentages of heavier hydrocarbons and inert gases. Natural gases vary widely in their degree of cleanliness and in the amounts of heavier hydrocarbons that are present. As the natural gases come from the well they may also contain nitrogen, carbon dioxide, hydrogen sulfide, and various contaminants such as salt water or sand and dirt. In most cases the water, solid particles, and the hydrogen sulfide are removed before the gas is used. In some cases, especially in overseas locations, the H₂S is left in the delivered fuel gas. Because of the nature of the gas turbine fuel control system, the gas reaching the fuel connection must be completely gaseous, that is, containing no liquid hydrocarbons. If there are liquids in the gas supply line, whether liquid hydrocarbons or water, they must be separated from the gas before reaching the turbine. Under some conditions a combination of filter-separator and heating is required. If any trace contaminants are left in the gas they must be evaluated to determine the effect on the turbine hot gas path.

B. Liquefied Petroleum Gases:

These gases are not normally used as turbine fuels because of their high commercial value, but have been used as backup fuels or in periods of temporary oversupply. Heating values of these gases are significantly higher than natural gases and usually require a fuel nozzle gas tip/control valve sized for the gas at the required operating conditions. Since these gases are easily liquefied, they always require heating to convert and maintain them as a gas at the turbine supply conditions. A minimum superheat of 50°F (28°C) will ensure that no liquid hydrocarbons reach the turbine. With proper heating and heat tracing of gas supply piping, operating experience with these types of fuels has been very successful.

III. PROCESS GASES

Many chemical processes generate surplus gases (tail or refinery gases) that make excellent turbine fuels when available. They are often mixtures of gases such as methane, hydrogen, carbon monoxide, and carbon dioxide that are left over after a petrochemical process. Since they often contain hydrogen or carbon monoxide, their ratio of rich-to-lean flammability limits becomes very large and may require special purging and other safety provisions. If their flammability limits are wide enough to make a normal ignition mixture flammable when diluted to exhaust conditions, a less hazardous start-up fuel is required.

The categories of process gases that deserve special consideration are those which are produced as a result of the production of steel. The classic steel making by-product gases are blast furnace and coke oven gases. Recently, a new process, COREX, results in a gas which appears attractive as a gas turbine fuel.

A. Blast Furnace Gases (BFG)

Blast furnace gases are not suited for use in General Electric gas turbines unless blended with either coke oven gas and/or natural gas. Generally BFG have heating values below specification. Other hydrocarbons such as propane or butane may also be used to supplement the BFG.

B. Coke Oven Gases

Coke oven gases are high in H_2 and CH_4 and may be used in conventional combustion systems without modification. These fuels may contain trace amounts of heavy hydrocarbons which could require special removal techniques to prevent carbon buildup on fuel nozzles.

C. COREX Gases

COREX gases are similar to oxygen blown gasified fuels, and may be treated as such. They are usually lower in H_2 content and have lower heating values than oxygen blown gasified fuels.

Further combustion related guidelines may be found in Bureau of Mines Circulars 503 and 622.

IV. GASIFICATION FUELS

Other fuel gases may be formed by the gasification of coal, petroleum coke or heavy liquids. The so-called medium Btu gases are generated by oxygen blown gasifiers. The heating values of these fuels range from 200 to 400 Btu/SCF and make excellent fuels for gas turbines. The H_2 content of these fuels is usually above 30% by volume with the H_2/CO mole ratio varying from 0.5 to 0.8. They are often mixed with steam or nitrogen for reasons of thermal NO_x control, cycle efficiency improvement or power augmentation. Steam or nitrogen may also be injected into the head end of the combustor, separately or mixed with the fuel. Because these fuels contain substantial amounts of hydrogen, they are usually not suited for DLN (Dry Low NO_x) systems (See Appendix 1). High hydrogen is a concern on DLN systems due to higher flame speeds and flashback potential instabilities. These fuels must be reviewed by Project Engineering.

Low Btu fuel gases are usually generated by air blown gasifiers and are treated on a case specific basis. Their heating values vary from about 150 Btu/SCF to below 100 Btu/SCF. The H_2 content of air blown fuels may vary from 8 to 20 % by volume with the H_2/CO mole ratio ranging from 0.3 to 3:1.

For gasification fuels a significant part of the total turbine flow comes from the fuel. In addition for oxygen blown fuels there is the diluent addition for NO_x control. Careful integration of the gas turbine with the gasification plant is required to assure an operable system. Due to the low volumetric heating value of both oxygen and air blown gases, special fuel systems and fuel nozzles are required.

V. FUEL PROPERTIES

A. Heating Values

While gas turbines can operate with gases having a very wide range of heating values, the amount of variation that a specific fuel system can accommodate is much less. Variation in heating value expressed in terms of a modified Wobbe Index (*Natural Gas*, E. N. Tirtsoo, Scientific Press Ltd., Beaconsfield, England, 1972) has the following limitations:

$$\text{Wobbe Index} = \frac{\text{Lower Heating Value (Btu/SCF)}}{[\text{Specific Gravity (air)} \times \text{Absolute Temp (R)}]^{1/2}}$$

For ignition and start up, the allowable variation in Wobbe Index is $\pm 5\%$. For operation above FSNL, the allowable variation in Wobbe Index may be considerably greater than $\pm 5\%$ and is primarily a function of the minimum allowable fuel nozzle pressure ratio as set by Combustion Engineering. At no time

during the steady state operation of the machine must the pressure ratio fall below the minimum established level. If the level is exceeded, a special gas fuel system with two sets of gas nozzle metering holes and two gas manifolds fed from two sets of control valves may be needed. When the heating value changes, the rate of change of heating value must be slow enough to prevent interaction with the gas turbine control system.

B. Flammability Limits

As implied earlier, gases containing hydrogen or carbon monoxide will have a ratio of rich-to-lean flammability limits that is significantly larger than that of natural gas. If the lean flammability limit is such that a normal ignition mixture would be flammable when diluted to gas turbine exhaust conditions, it is regarded as a hazardous gas. In this case, a start-up fuel such as natural gas or distillate oil is used to bring the turbine up to some steady state running condition. At this time, a transfer to the hazardous gas can be accomplished safely. Typically, gases with greater than 5% hydrogen by volume require a separate startup fuel.

At the other end of the scale, natural gas with large percentages of an inert gas such as nitrogen or carbon dioxide will have a ratio of rich-to-lean flammability limits that is less than that of pure natural gas. If this ratio when determined at standard conditions of one atmosphere and 60°F (15.6°C) is less than 2.2 to 1 based upon volume mixtures, experience indicates that problems can be expected in maintaining stable combustion over the full operating range of the turbine.

C. Temperature and Supply Pressure

Natural gas is usually supplied at ambient temperatures unless a gas compressor has been used to deliver the gas to the normal supply pressure (See Appendix 3). In these cases the gas temperature needs to be controlled at the startup to limit the Wobbe number range to that previously defined. Also, 50°F (28°C) superheat is required above any condensable hydrocarbon/water dewpoint at the delivery pressure.

Process gases and liquified petroleum gases can usually be handled at temperatures up to around 350°F with minor changes in the fuel system. Fuels from gasification processes are often delivered at temperatures of 400°F (204°C) or above for cycle efficiency reasons. These are dealt with on a case by case basis, and should be reviewed by Project Engineering.

VI. CONTAMINANTS

The fuel gas delivered to the gas turbine must not contain any significant concentrations of liquid droplets or solid particles. These must be removed by the fuel producer or supplier before delivery to the gas turbine.

The contaminants likely to be found in fuel gas, of course, depend on the kind of gas. Some of the contaminants which are likely to be found are listed below.

1. Tar, lamp black, coke
2. Water, salt water
3. Sand, clay
4. Rust
5. Iron sulfide
6. Scrubber oil or liquid
7. Lube oil

8. Naphthalene

PAGE 6 OF 10

9. Gas Hydrates

For particulate and trace metal contaminants the allowable concentrations in the gas turbine fuel as set forth in Table 3 are determined by the actual concentrations in the mass flow through the turbine hot gas path. The limit set for the fuel gas is the concentration, when diluted by the injected (steam, water etc.) diluents and the combustion air flow, that falls within an acceptable range for the turbine hot gas path parts. There is no recognized test method for determining turbine inlet contaminants for particulates or trace metals.

Turbine inlet and fuel equivalent contaminant limits, XE and XF_e, given in Table 3 are the total from all sources, and they contain the contributions from steam/water and air. The nominal limits on steam/water for NO_x control and/or power augmentation is 10 ppb for Na plus K and 100 ppb for solids relative to the combustion gases. The nominal air limit is 5 ppb for Na plus K at the compressor inlet.

A. Solids

The specification on the solid contaminants carried in the fuel is given in Table 3. Solid contaminants may cause hot corrosion, fouling deposits, and erosion, depending on the nature of the contaminant. Also, solids add to the exhaust particulates which are controlled in some jurisdictions.

Particulate matter contamination in the fuel gas can cause erosion and plugging of gas orifices, and deposition and erosion along the hot gas path. For these reasons the specification given in Table 3 shows solids in the gas shall not exceed 600 ppb by weight in the turbine inlet, and no more than about 1% by weight can exceed 10 microns, depending on particle density and shape. Particles of this size and larger can cause severe erosion (See Appendix 4). For low Btu gases the fuel contribution of solid particles at the turbine inlet is increased over that for natural gas, and the solid particle limit is therefore decreased.

B. Liquids

Liquefied fuel droplets or slugs entering the combustor can cause rapid excursions in firing temperature and gas turbine load. Fuel droplets can survive the combustor to burn downstream in the hot gas path, causing over-temperature and even melting of hot gas path components. In the case of low calorific value gases, the presence of liquid water has been found to cause blowout, due to a rapid lowering of flame temperature.

Liquids in a gas system tend to accumulate at low points, and tend to move intermittently as slugs during changes in fuel flow. Liquids at the interface of the gas turbine fuel system should be removed by conventional liquid separators. Liquid condensation after the gas turbine interface can be avoided by superheating.

C. Sulfur

Experience has shown that oxidation/corrosion rates are not significantly affected by fuel sulfur levels up to about 1% sulfur. Hot corrosion of hot gas path parts is controlled by specifying the fuel alkali levels at 20 ppb at the turbine inlet (See Table 3). This controls the extent of alkali sulfate formation, which is the salt responsible for hot corrosion. Unless sulfur levels are extremely low, alkali levels are usually limiting in determining hot corrosion of hot gas path materials.

If heat recovery equipment is used the concentration of sulfur in fuel gases needs to be specified. Severe corrosion from sulfuric acid dew results if a heat recovery steam generator (HRSG) has metal temperatures below the sulfuric acid dewpoint. Approximate dewpoints for a natural gas fuel are 170°F (76.7°C)

for 30 ppm sulfur, and 250°F (121°C) for 0.3% sulfur. These are approximate values, being dependent on boiler and turbine design.

Units utilizing ammonia injection downstream of the gas turbine for NO_x control can experience the formation of ammonium sulfate and bisulfate on low temperature evaporator and economizer tubes. Such deposits are quite acidic and therefore corrosive. Also, in the presence of minute quantities of chlorides which are supplied by the inlet air, cracking of AISI 300 series stainless can occur. Deposition rates of ammonium sulfate and bisulfate are determined by the sulfur content of the fuel, tube temperature and boiler design. Fuels having sulfur levels above those used as odorents for natural gas should be reported to Project Engineering.

Sulfur burns mostly to sulfur dioxide, but 5%-10% oxidizes to sulfur trioxide. The latter can result in sulfate formation, and may be counted as particulate matter in some jurisdictions.

When considering fuel gases containing H₂S (sour gas fuels) materials for fuel handling should be checked to see that they comply with NACE Standard, MR0175-93.

D. Trace Metal Contaminants

There are four elements of primary concern relative to hot corrosion. (See Liquid Fuel Specification GEI-41047, and Gas Turbine Inlet Air Treatment GER-3419) These are the trace metal contaminants sodium, potassium, vanadium and lead. Only the first of these is likely to be encountered in most gases, however potassium along with sodium is found in coal derived fuels. Levels of calcium and magnesium are also specified, as these trace metals produce hot gas path deposits. The levels allowed are given in Table 3. Appendix 2 gives relationships for contaminants from all sources, air, fuel, steam and water, and the determination of fuel and turbine inlet limits.

The amount of alkali metals, particularly sodium and potassium, entering the hot gas path from all sources, must be minimized to avoid hot corrosion problems of turbine materials. Corrosive alkali sulfates form on hot gas path hardware when sodium and potassium compounds from any source react with sulfur in the combustion gases.

Contributions to the alkali in the combustion gases can come from fuel, air, or from water or steam from injection. Although, the less alkali in the combustion gases the better, for practical purposes alkali levels are restricted to 20 parts per billion by weight at the turbine inlet. This results in the usual specification of 1 ppm (Na+K) relative to the fuel for a natural gas with a combustion gas to fuel weight ratio of 50:1.

APPENDIX 1

PAGE 8 OF 10

Gas Fuels for Dry Low NO_x Combustors

The following table encompasses the constituent limits which will assure stable, premix combustion in the dry low NO_x product line. Candidate fuels which do not meet these limits should be referred to Project Engineering.

MIN (% Vol)	SPECIES	MAX (% Vol)	Basis of %
85	CH ₄	100	Reactant species
0	C ₂ H ₆	15	"
0	C ₃ H ₈	15	"
0	C ₄ + (paraffin's)	10	"
0	CO	15	"
0	H ₂	10	"
0	O ₂	10	"
0	CO ₂	15	Total species (reactants and inerts)
0	N ₂	30	"

APPENDIX 2

Equivalent Contaminant Relationships

The following relationships can be used to determine turbine inlet contaminant and fuel equivalent contaminant concentrations to compare to limits given in Table 3. In general, for mass balances on the flows and on the contaminants from fuel, air and steam/water at the turbine inlet

- (1) $E = F + A + S$
- (2) $(XE)E = (XF)F + (XA)A + (XS)S$

where:

A, F, S and E are the mass flows of air, fuel, injected steam/water and combustion gases at the turbine inlet, respectively, and

XA, XF, XS, and XE are the contaminant concentrations (ppm by weight) in the inlet air, in the fuel, in the injected steam/water, and in the combustion gases at the turbine inlet, respectively.

The fuel equivalent concentration of contaminants (XF_e) is (dividing (1) and (2) by F)

$$(3) \quad XF_e = XE(1 + A/F + S/F) = XF + XA(A/F) + XS(S/F)$$

For example for a natural gas contaminated with salt at a sodium concentration of 0.1 ppm, an air sodium contamination of 5 ppb, and a steam contamination of 20 ppb, the equivalent sodium in the fuel for A/F = 50 and S/F = 1 is from equation (3)

$$XF_e = 0.1 + 0.005(50) + 0.020(1) = 0.37 \text{ ppm}$$

This is the amount of sodium considered to come from a fuel source only, which gives the same sodium concentration at the turbine inlet as from the combined three sources.

The turbine inlet concentration, XE, is by (3)

$$XE = XF_e / (1 + A/F + S/F) = 0.37 / (1 + 50 + 1) = 0.0071 \text{ ppm} = 7.1 \text{ ppb}$$

These values are well within the sodium specification values of 1 ppm on a fuel basis (XF_e), and 20 ppb for the turbine inlet concentration (XE). XE and XF_e values for all contaminants are given in Table 3.

APPENDIX 3

The gas fuel supply pressure must exceed the maximum fuel nozzle pressure drop and the minimum gas control valve pressure drop necessary to maintain sonic velocity at the control valve throat. Typical minimum and maximum standard fuel gas supply requirements are given below. For gas fuel pressures outside these ranges contact Project Engineering. Supply pressure requirements for IGCC and other low and medium Btu gases may differ from those shown in the Table. Contact Project Engineering in this case.

SUPPLY PRESSURES (Psig)

Model Series	Required Minimum		Maximum Allowable
	Std. @59°F (15°C)	DLN @59°F (15°C)	
3002 J	115	—	205
5001 P	200	—	275
5002 C	175	—	225
6001 B	240	285	350
6001 FA	310	350	450
7001 EA	260	290	350
7001 FA	310	350	450
9001 E	250	300	450
9001 FA	315	350	450
LM6000	655	655	695

APPENDIX 4

The effective particle size for erosion considerations is determined by a particle's terminal settling velocity. The size and density distribution of the solid particles must be such that not more than 1.0 percent by weight of the particles shall have a terminal settling velocity in air (70°F (21°C) and 30 inches Hg, absolute) greater than 14 inches per minute, and not more than 0.1 percent shall have a terminal settling velocity in excess of 23 inches per minute.

For a solid spherical particle, Stoke's Law of settling permits calculating the terminal settling velocity if the particle size and shape and particle specific gravity are known. The following tabulation gives the spherical particle diameters equivalent to the limiting terminal settling velocities for particles of specific gravity 2.0 and 4.0

Settling Velocity	Specific Gravity (based on water)	Equivalent Spherical Partical (inches/min) Diameter (microns)
14	2	10
23	2	13
14	4	7
23	4	9

APPENDIX 5 - APPLICABLE DOCUMENTS

MR0175-93, NACE Standard, Sulfide Stress Cracking Resistant Metallic Material for Oilfield Equipment.

Bureau of Mines Bulletin 622, Flammability Characteristics of Combustible Gases and Vapors. 1965

Bureau of Mines Bulletin 503, Flammability Characteristics of Combustible Gases and Vapors. 1950

GEI-41047 Gas Turbine Liquid Fuel Specification

GER-3419 Gas Turbine Inlet Air Treatment

Natural Gas, E. N. Tiratsoo, Scientific Press Ltd., Beaconsfield, England. 1972



GE Industrial & Power Systems

General Electric Company
One River Road, Schenectady, NY 12345
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Table 2.5PAGE 1.....CF 1.....

Design & Normal Operating Coal Analyses

Coal Analysis (Wt %, Dry Basis):

	<u>Design</u>	<u>Normal</u>
Carbon	77.43	77.43
Hydrogen	4.95	4.95
Nitrogen	1.46	1.46
Sulfur	3.50 Max	2.57
Oxygen	5.22	5.22
Ash	8.37 Max	8.37

BECHTEL
CORP.
HOUSTONDESIGN BASIS
DOCUMENT

SPECIFICATION NO.

REV

22269-A-030

1

**Tampa Electric IGCC Project
Polk Power Station Unit No. 1**

Heat and Material Balance	Design Case
Stream ID:	411
Name:	Clean Gas from RG/CGE
Phase:	Vapor
Fluid rates, lb-mo/hr	
(1) CO	7,741.700
(2) H ₂	5,831.400
(3) CO ₂	2,089.900
(4) H ₂ O	61.300
(5) C ₁	31.000
(6) AR	204.100
(7) N ₂	1,023.500
(8) H ₂ S	0.160
(9) COS	6.000
(10) O ₂	0.000
Total fluid, lb-mo/hr	16,989.059
NMW solid rates, lb/hr	
(11) Coal	0.000
(12) Slag	0.000
(13) Char	0.000
(14) NaCl	0.000
Total NMW, solid, lb/hr	0.000
Total rate, lb/hr	359,372.313
Temperature, °F	651.534
Pressure, psia	300.000
Enthalpy, MM solid, lb/hr	95.360
Molecular weight*	21.153
Mole frac vapor*	1.000
Mole frac liquid*	0.000
Weight frac NMW solid	0.000
-----VAPOR-----	
Flow, M ft ³ /hr	687.369
Cp, Btu/lb-f-l	0.365
Density, lb/ft ³	522.823
TH cond, Btu/hr-ft-l	0.05227
Viscosity, cP	0.02802
-----LIQUID-----	
Flow, gal/min	N/A
Cp, Btu/lb-f	N/A
Density, lb/m ft ³	N/A
Surface tension, dyns/cm	N/A
Thermal cond, Btu/hr-ft-f	N/A
Viscosity, cP	N/A
-----SOLID-----	
Cp, Btu/lb-f	N/A
Density, lb/ft ³	N/A

* Solids Free Basis

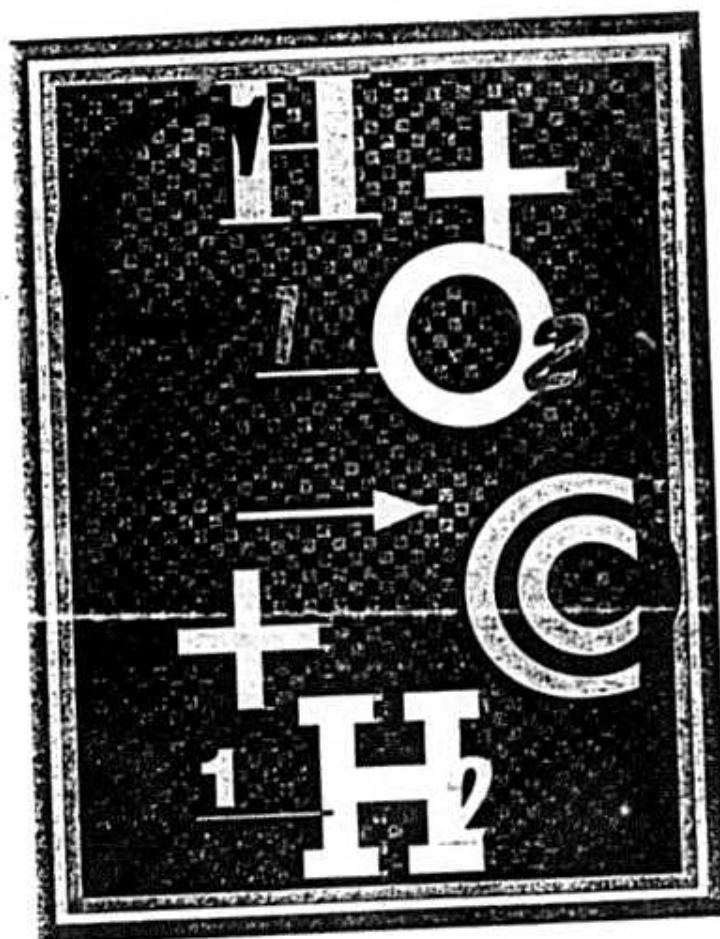
Document No. 18-5

Texaco Fuel Flexibility References

1. Texaco brochure titled "Texaco Gasification Process for Solid Feedstock"
2. Texaco brochure titled "Texaco Coal Gasification"
3. Texaco paper presented at 1989 Pittsburgh Coal Conference "Cool Water Operating Results - Implications for New IGCC Plants"
4. Texaco paper presented at 1991 New York Water Pollution Control Association "Gasification of Sewage Sludges"
5. Texaco brochure titled "Technology for Energy and the Environment"
6. List of awards earned by the Cool Water Program
7. Technical paper presented in 1990 at the Netherlands IEA Expert-Meeting on the Use of Coal-Gasification Slag "Commercial Application of Slag from Texaco coal Gasification Plant in UBE Ammonia"
8. Texaco paper presented at 1995 EPRI Gasification Conference in San Francisco "Texaco Gasification: Powering for the 90s"
9. Texaco newsletter from November 1, 1995 "Texaco Gasification Technology Selected by Exxon, Koch"
10. EPRI listing of available Texaco Gasification reports
11. Texaco listing of gasification papers available for distribution



1



*Texaco
Gasification
Process
for Solid
Feedstocks*

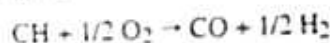
Over the last 35 years, the Texaco Gasification Process (TGP) for Solid Feedstocks has been licensed in more than 15 commercial facilities to manufacture synthesis gas (Syngas). Primarily hydrogen and carbon monoxide, this synthesis gas is a basic building block for many agricultural and chemical industry applications. It may be used for:

- Chemical synthesis of ammonia, methanol and oxochemicals
- Hydrogen manufacture
- Electricity production
- Fuel for industrial boilers and process heaters
- Reducing Gas for metallurgical applications

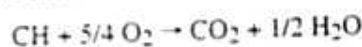
Feedstock flexibility and high operating reliability are among the technology's major advantages. Many different solid feedstocks, such as coal and petroleum coke, have been gasified using this process. Many plants run on a mixture of feedstocks and most can switch feedstocks without interrupting operations. Some even use hydrocarbon-containing byproducts from other operations. This technology easily meets the most rigorous environmental standards. The process is proven to be reliable, flexible and adaptable to the ever-changing needs of the worldwide refining, chemical and power generation industries.

The Gasification Processes described in this brochure apply only to solid feedstocks. For information regarding gasification of liquid and gaseous feedstocks, ask your Texaco Representative about other literature available.

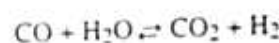
The Texaco Gasification Process for Solid Feedstocks is a non-catalytic, continuous, entrained flow, partial oxidation process. Under the TGP, carbonaceous solids react at high temperature and usually at high pressure with oxygen, oxygen-enriched air, or air according to the basic overall reaction:



Although the detailed chemistry and thermodynamics of partial oxidation technology are very complex, valuable insight can be gained by considering two additional concurrent reactions: the complete oxidation of the hydrocarbon to carbon dioxide (CO_2) and water



and the reversible water-gas shift reaction.

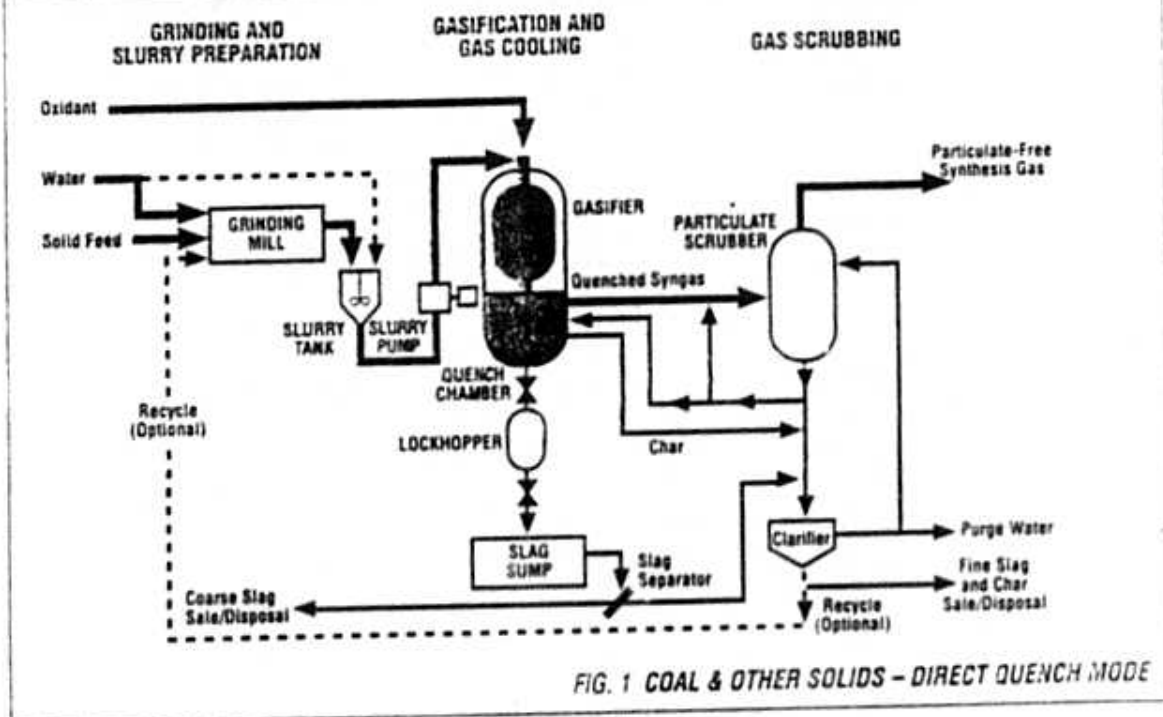


Both reactions are exothermic and generate very high temperatures within the reactor. These conditions necessitate the use of a temperature moderator (such as water, steam, or carbon dioxide) to simultaneously control temperatures at appropriate levels and to optimize the hydrogen to carbon dioxide ratio for downstream chemical synthesis.

The raw product gas contains principally carbon monoxide (CO) and hydrogen (H_2). Also present are some carbon dioxide (CO_2) and steam, plus trace amounts of argon, nitrogen, methane and (if the feed contained sulfur) hydrogen sulfide and carbonyl sulfide. No heavy hydrocarbons, tar or other potentially troublesome by-products are formed. Typical synthesis gas compositions are shown for various feedstocks in Table 1. Because the gasifier operates at elevated temperatures in a highly reducing atmosphere, it leaves neither oxides of sulfur nor nitrogen in the product gas.

TABLE 1 SYNGAS PRODUCTION FROM VARIOUS CARBONACEOUS FEEDS

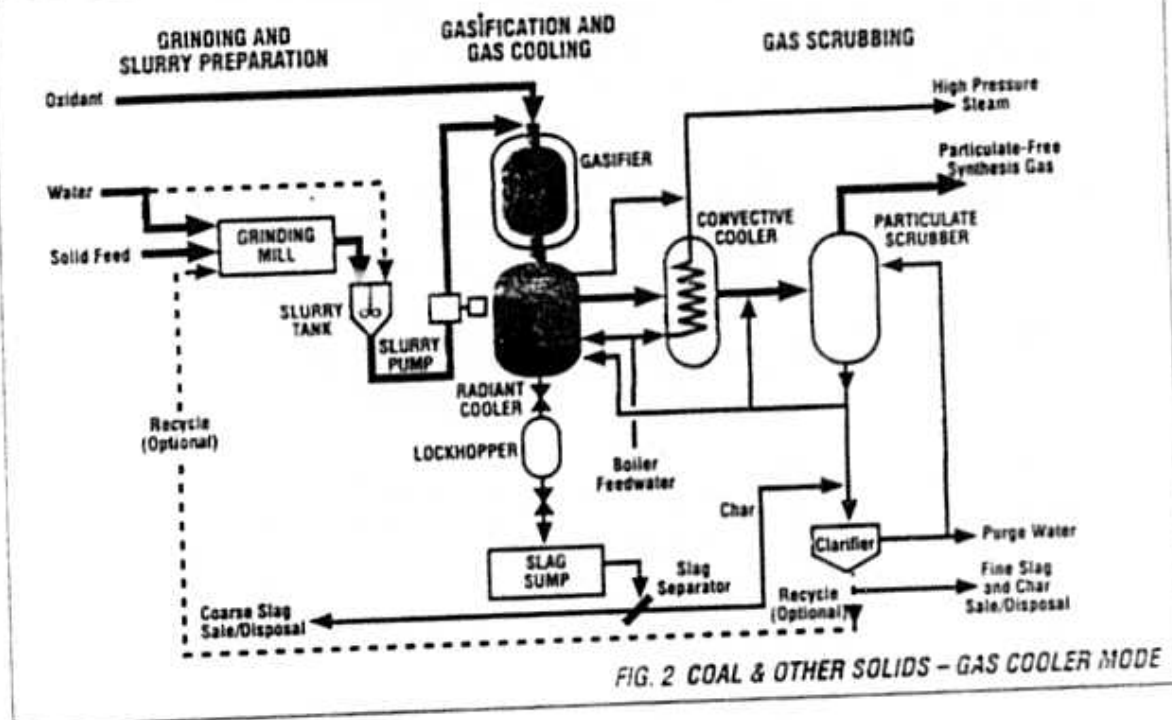
FEED TYPE	COAL					PETROLEUM COKE		COAL LIQUEF. RESIDUE	
	PITTSB. NO. 8	FRENCH	UTAH	GERMAN	S. AFRICAN	DELAYED	FLUID	MOLTEN	SLURRY
Feedstock Dry									
Anal., wt. Pct									
Carbon	74.16	78.08	68.21	73.93	65.60	88.50	85.98	68.39	68.39
Hydrogen	5.15	5.26	4.78	4.65	3.51	3.90	2.00	4.75	4.75
Nitrogen	1.18	0.85	1.22	1.50	1.53	1.50	0.98	0.98	0.98
Sulfur	3.27	0.47	0.37	1.08	0.87	5.50	8.31	1.87	1.87
Oxygen	6.70	8.23	15.69	5.85	7.79	0.10	2.27	2.21	2.21
Ash	9.54	7.11	9.73	13.01	20.70	0.50	0.46	21.80	21.80
Higher Heating Value									
Btu/lb	13,600	14,000	11,800	13,200	11,200	15,400	13,800	12,700	12,700
Kcal/kg	7,540	7,780	6,570	7,330	6,220	8,550	7,665	7,060	7,060
Product Composition									
Mol Pct									
Carbon Monoxide	39.95	37.36	30.88	39.46	36.53	46.20	47.14	46.31	33.48
Hydrogen	30.78	29.26	26.71	29.33	26.01	28.69	24.33	35.54	28.56
Carbon Dioxide	11.43	13.30	15.91	12.59	15.67	10.68	13.16	6.41	13.09
Water	16.43	19.43	25.67	17.47	20.82	12.37	12.67	10.46	23.72
Methane	0.04	0.16	0.22	0.25	0.02	0.17	0.09	0.27	0.23
Nitrogen & Argon	0.49	0.37	0.50	0.60	0.68	0.55	0.42	0.45	0.42
Hydrogen Sulfide + Carbonyl Sulfide	0.88	0.12	0.11	0.30	0.27	1.34	2.19	0.56	0.50



The feedstock is typically wet-ground in conventional grinding mills and slurried with water to create concentrations normally greater than 65 weight percent. Therefore, energy-intensive drying of the solid feed is not necessary. Wet grinding eliminates dust control systems and explosion hazards. The slurry feed system provides greater operational simplicity and control even when high pressure gasification is employed. The slurry is fed simultaneously with oxygen or air to the gasifier through a burner. The water in the slurry serves as a transport medium and temperature moderator.

The hot gas exiting the gasifier is cooled directly in a quench chamber by contact with water or indirectly in a syngas cooler (waste heat boiler) to recover excess heat/energy. Plants using these cooling modes have been operational for many years. The desired fuel specification range, level of integration with other facilities, and ultimate end-use of the syngas generally determine the preferred mode of gas cooling.

In the direct quench mode (Figure 1), the hot gas exiting the gasifier contacts water in the quench chamber which is located in the bottom of the gasifier vessel. The raw gas is cooled and saturated with steam. This mode is preferred for production of high purity hydrogen and, when properly integrated into the remainder of the facilities, is efficient for electric power generation. The direct quench mode is considered to be a waste-management gasifier, because it can convert low-value waste and refinery streams to synthesis gas. The direct quench mode offers a significant investment savings and yet provides a highly efficient method of raising process steam for downstream uses (e.g. shifting to hydrogen, saturation of fuel gas).



In the syngas cooler mode (Figure 2), hot gas is indirectly cooled in a specifically designed syngas cooler where high pressure export steam is generated. If desired, additional gas cooling is possible in an economizer. This mode of cooling is preferred for the manufacture of fuel gas, reducing gas, power generation and other petrochemical applications. It is selected when shift conversion is not required and where recovery of excess heat in the synthesis gas is desired to maximize energy efficiency.

Gas Scrubbing

Gas Scrubbing
The cooled or saturated raw synthesis gas from the gasifier is water-scrubbed in a soot scrubber. This removes essentially all traces of entrained particles, principally unconverted carbon, ash and metals. This soot-scrubbing equipment, using several stages of particulate removal, has many years of commercial application.

Ash Removal

Ash Removal

Most of the ash is removed as a solid, glass-like slag through a water-sealed, depressurizing lockhopper system. This material is moved to a collection sump where it is separated from the water for further handling. The fines in the water are pumped from the sump and routed as a dilute slurry to the clarifier for gravity separation or filtration. The scrubbing water stream is also sent to a clarifier for removal of entrained char particles. The return of clarifier overflow to the gas scrubber conserves water. A fraction of the water may be purged from the system to control the level of dissolved solids and to prevent scaling in the water system. The clarifier concentrates the char and fine slag in the underflow for further handling or recycling.

Applications

All ranks of coals, petroleum cokes and coal liquefaction residues may be gasified by the Texaco Gasification Process for Solid Feedstocks. Table 2 lists some types of feedstocks gasified at Texaco's TGP Pilot Plants in Montebello, California. The Ube Ammonia Coal Gasification Plant in Ube City, Japan, imports coal and coke as feedstock and has demonstrated commercial flexibility on a wide variety of solid feeds as shown in Table 3.

Any carbonaceous solid that can form a pumpable, concentrated slurry with water is a suitable feedstock. Additives may be used to enhance the slurrying properties of some feedstocks.

Commercial applications of the Texaco Gasification Process for solid carbonaceous feedstocks were the direct result of over forty years of experience with partial oxidation using gaseous and liquid feeds. Results are supported by the construction and operation of a series of pilot, demonstration and commercial plants, some of which are listed in Table 4. The data obtained from these units provides the basis for design and insures the reliable operation of commercial plants for different applications.

TABLE 2 EXAMPLES OF FEEDSTOCKS GASIFIED IN THE TEXACO MONTEBELLO PILOT PLANTS

COAL	PETROLEUM COKE
• Anthracite	• Fluid
• Semi-anthracite	• Delayed
• Bituminous	• Calcined
• Sub-bituminous	• Fluid coke from tar sands bitumen
• Lignite	
COAL LIQUEFACTION OTHER RESIDUE	
• Solvent Refined Coal Residue (SRC I & II)	• Lurgi tar/oil
• H-Coal Residue	• Sewage sludge
• Exxon Donor Solvent (EDS) Residue	• Waste oils

TABLE 3 UBE AMMONIA PLANT

COAL:	Australian Coal Chinese Coal South African Coal Canadian Coal Colombian Coal Petroleum Coke
CAPACITY:	1,650 tons of coal per day
PRODUCT:	Ammonia/Urea
BY-PRODUCTS:	Sulfur - Commodity sales Slag - To cement plant CO ₂ - To bottling plant

TABLE 4 TGP PLANT SUMMARY

OWNER	TYPE	LOCATION	COAL CAPACITY	START-UP	HEAT RECOVERY	PRODUCT
Texaco Inc.	Pilot	California	15 TPD	1973	Direct Quench	R&D
Texaco Inc.	Pilot	California	15 TPD	1978	D.Q./Gas Cooler	R&D
Tennessee-Eastman	Commercial	Tennessee	900 TPD	1983	Direct Quench	Acetic Anhydride
Cool Water	Commercial	California	1,000 TPD	1984	Gas Cooler	Electric Power
Ube Ammonia	Commercial	Japan	1,650 TPD	1984	Direct Quench	Ammonia
SAR	Commercial	Germany	800 TPD	1986	D.Q./Gas Cooler	Oxo-Chemical/Hydrogen
Lunan	Commercial	China	400 TPD	1992	Direct Quench	Ammonia
Shougang	Commercial	China	1,100 TPD	1994	Gas Cooler	Fuel Gas
Weihe	Commercial	China	1,650 TPD	1996	Direct Quench	Ammonia
Shanghai	Commercial	China	1,100 TPD	1996	Gas Cooler	Town Gas/Chemicals

Figures 3 and 4 depict the Texaco Gasification Power Systems (TGPS) in the quench and full heat recovery mode. These involve the commercially proven integration of Texaco's gasification technology with an Integrated Gasification Combined Cycle (IGCC) power plant.

Optimization of individual units and subsystems – especially cost-effective use of low-level heat – is fundamental to superior heat rate performance of TGPS IGCC applications. Early IGCC configurations used syngas moisturization and later configurations used simple nitrogen injection for NO_x control prior to feeding the combustion turbine. In contrast, TGPS allows for nitrogen preheating, nitrogen moisturization and higher levels of syngas moisturization.

TGPS is not limited to specific technology selections related to oxygen plant, sulfur plant, or power plant suppliers and can operate either in the syngas cooler or in the quench

gasification configuration. Because of this technological flexibility, TGPS allows a wide variety of choices in power plant feedstock (coal, petroleum coke, orimulsion, heavy oil, wastes) without sacrificing plant performance or compromising environmental permits.

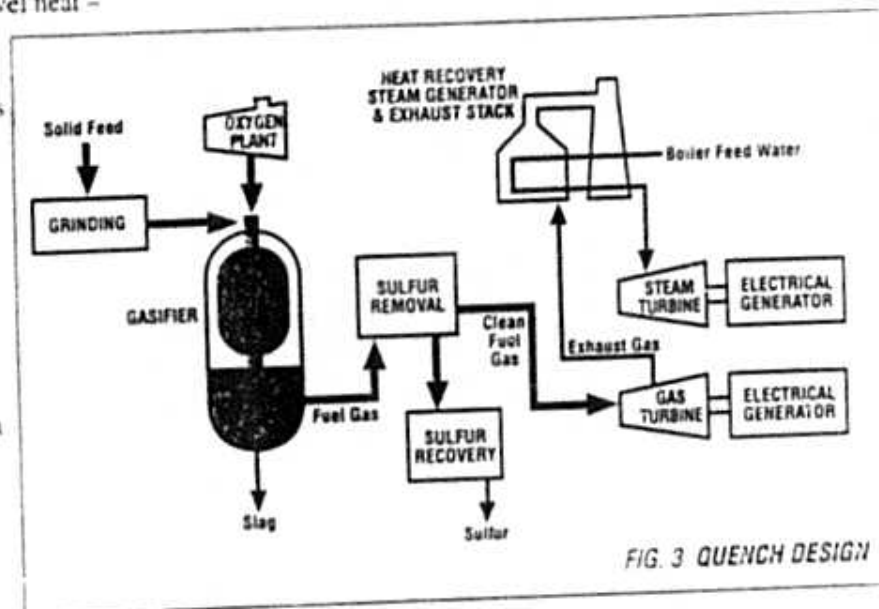


FIG. 3 QUENCH DESIGN

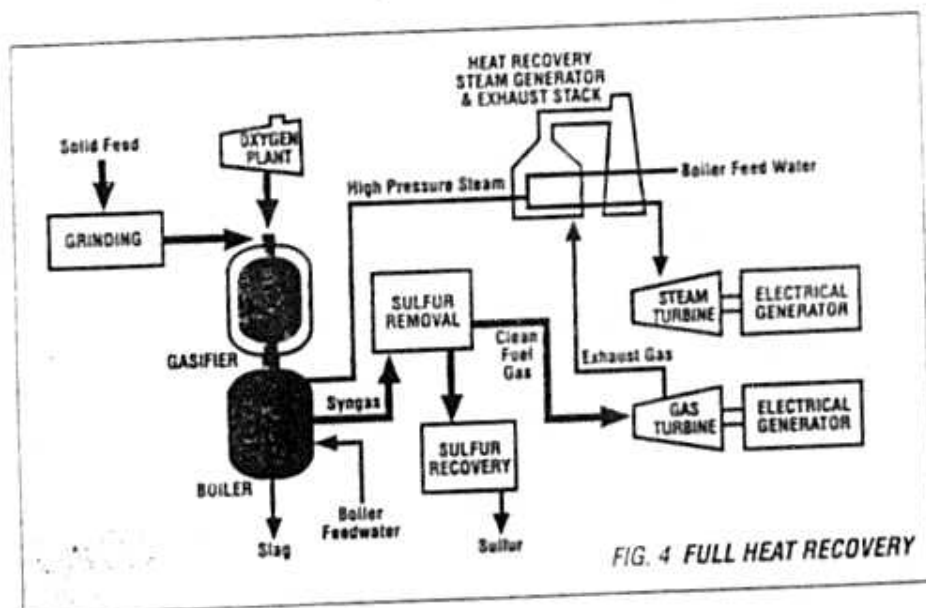


FIG. 4 FULL HEAT RECOVERY

Process Characteristics

The unique features of the Texaco Gasification Process for Solid Feedstocks make it attractive to numerous potential users. Its key strengths are:

Feedstock Flexibility

The process is relatively insensitive to solid feedstock properties such as particle size, moisture level, reactivity and caking. This permits the use of the most economical feedstock available at a given time.

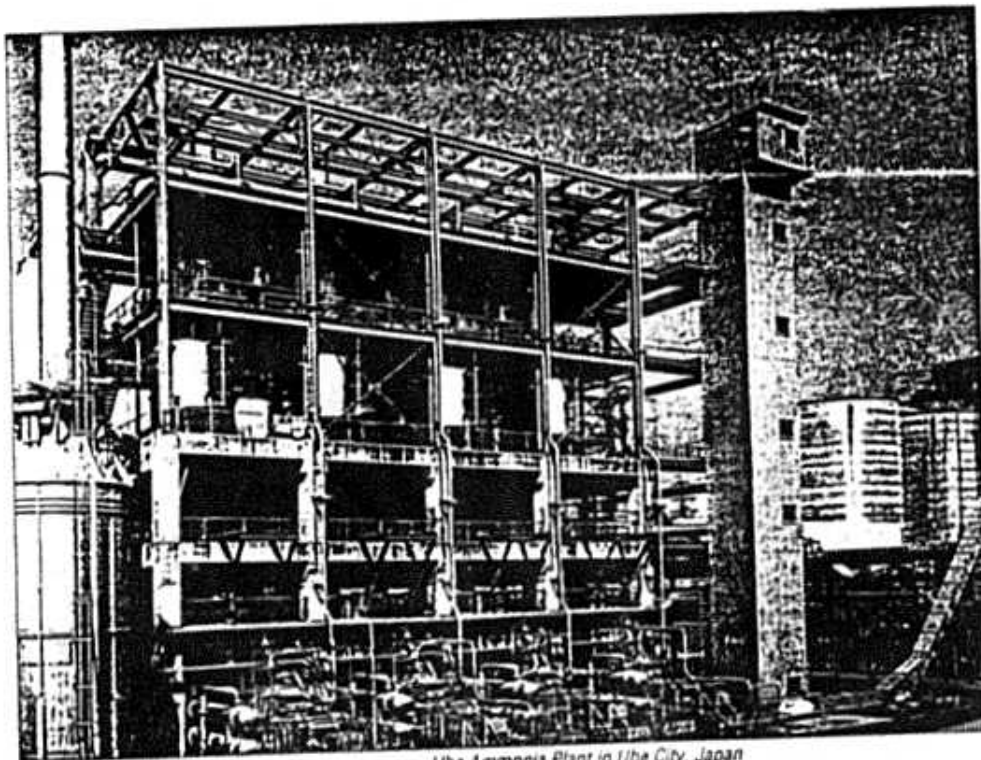
Simplicity and Reliability

The gasifier has no moving parts. Its burner is easy to remove and replace quickly and requires no gasifier cool down. The slurry feed system is patterned after the liquid hydrocarbon feed system and is proven to be highly safe and reliable. A

provision for slurry storage allows minor repairs to slurry preparation equipment without process interruption. This system efficiency reduces labor and supervision requirements.

Throughput, Turndown and Load Following

High operating temperatures generate a nearly complete carbon conversion to synthesis gas in seconds. Short residence time and high-pressure capability yield high feed throughput and gas production in moderate-sized process equipment. This reduces plant area requirements and capital costs. The superb load following characteristics even match requirements for refining, chemical and power generation applications. Single train turndowns of 50% of design capacity are typically achieved with no significant effect on equipment or performance.



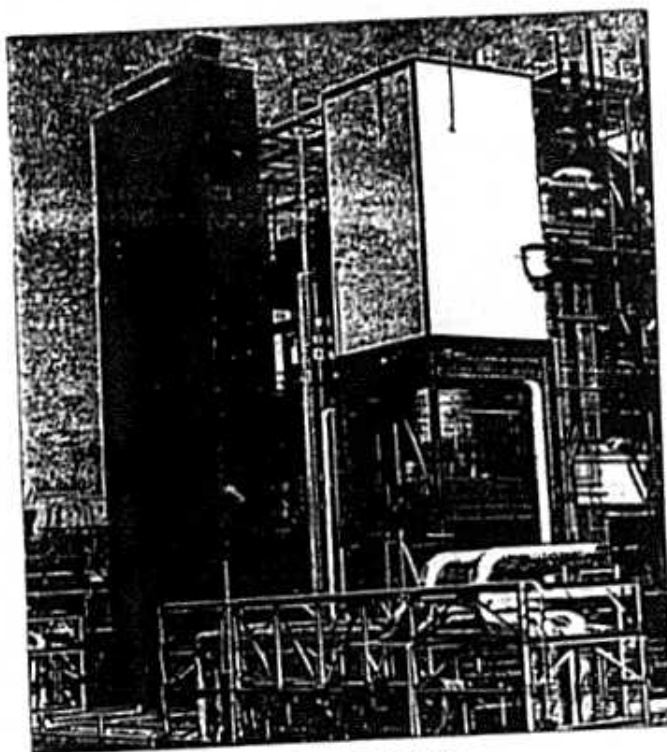
Ube Ammonia Plant in Ube City, Japan

Process Efficiency

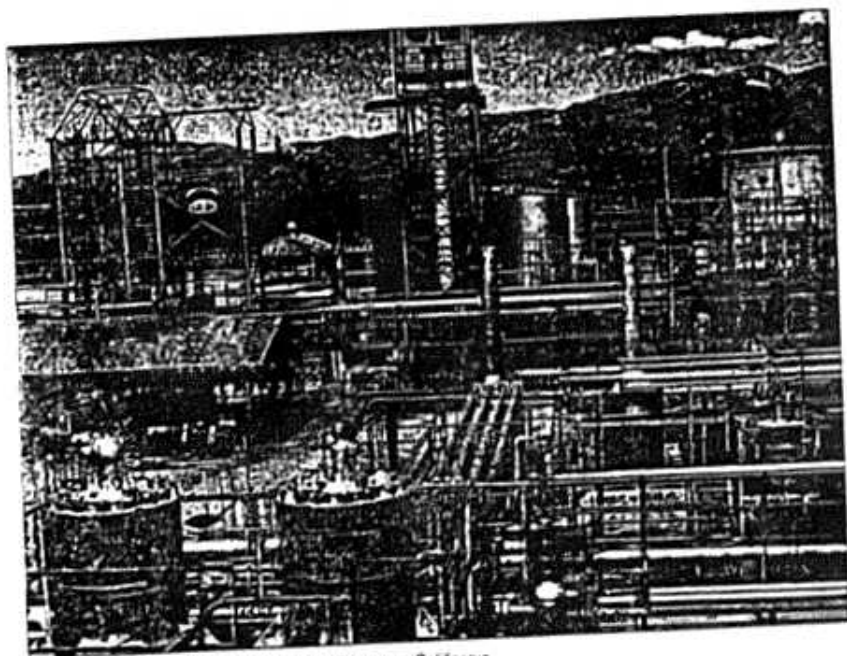
Nearly complete conversion of the feed to product gas can be accomplished in a single pass. For complete conversion, the high-carbon fraction of the rejected solids may be recovered and recycled to the gasifier. Gas stream sensible heat is recovered by either direct quenching or indirect gas cooling.

Environmental Aspects

The high reaction temperature eliminates the formation of hydrocarbons heavier than methane. When cooled, molten slag from the gasifier forms hard glassy particles which are low in carbon. Tests confirm that these particles are essentially non-leaching. Other process effluents are purge water and clarifier underflow solids. The purge water may be treated by using available wastewater technology. The clarifier underflow material consists of smaller size particles with somewhat higher carbon levels. It is essentially the same material as the slag and can be disposed of with the slag or recycled to the slurry preparation section.



Tennessee Eastman Facility in Kingsport, Tennessee



Montebello Research Laboratories in Southern California

The Texaco Gasification Process for Solid Carbonaceous Feedstocks is offered for license by Texaco Development Corporation, a wholly-owned Texaco Inc. subsidiary responsible for worldwide licensing of Texaco technologies. Texaco Development Corporation provides comprehensive assistance, on a fee basis, to clients interested in this process. These services include:

- Feed sample analysis
- Feasibility and design optimization studies
- Bench and pilot plant testing
- Process design packages
- Basic engineering
- Detailed engineering support
- Start-up assistance
- Operating training on process simulator
- Operating computer programs
- Continuing technical support and technology updates
- Ongoing technical exchange with operators and engineers of TGP plants
- Plant optimization and debottlenecking studies
- Vendor assistance

SUMMARY

Many years of successful operating experience continue to advance the state-of-the-art Texaco Gasification Process. It is a highly economical and efficient tool for converting all types of feedstocks to a synthesis gas (hydrogen and carbon monoxide) which can be used for power generation or for the manufacture of a wide variety of products.

For further information, please contact:

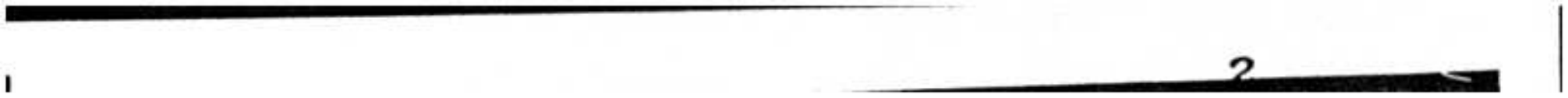
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QUESTIONS AND ANSWERS ABOUT TEXACO COAL GASIFICATION

- Q • Has a Texaco Coal Gasification plant produced electric power on a commercial scale?**
- A • Yes.** Since May 1984, the Cool Water Plant in California's Mojave Desert has been converting 300 tons of coal per day to 120 megawatts of electricity. Future plants will use gasification modules of approximately the same size.
- Q • Isn't this type of facility too much like a chemical plant for utility personnel to operate?**
- A • No.** Since startup, Cool Water has been operated successfully by utility personnel.
- Q • Okay, but isn't a gasification plant expensive to build and operate?**
- A • Capital costs are very competitive with other types of coal-based power plants. What makes coal gasification plants especially attractive is that operating and maintenance costs are approximately 10 percent lower.**
- Q • Is coal gasification suitable to other applications?**
- A • Yes.** A Texaco gasification plant can be designed to produce commercial quantities of steam, hydrogen, and methanol, as well as other products.
- Q • Is gasification really commercially proven?**
- A • Yes it is.** The first plant was licensed over 30 years ago, and over 90 Texaco gasification plants have operated worldwide.
- Q • Aren't there other coal gasification technologies?**
- A • Yes, but none have amassed the commercial operating experience of the Texaco process.**
- Q • Conventional coal burning plants have environmental problems. Is this true of the Texaco process?**
- A • No, in fact, it uses coal more cleanly than any other commercially available technology. The Cool Water Plant has been the world's cleanest coal-based power facility.**
- Q • Doesn't a Texaco gasification plant consume more water than a conventional coal plant?**
- A • You might think so, but the process actually consumes less water than other coal burning technologies. Water recycling and reuse are incorporated in the design.**
- Q • Is Texaco prepared to offer assistance to coal gasification clients?**
- A • Providing quality service is a priority. The company is ready to help in all phases of your gasification program with a full range of services, from planning through operations. Highly experienced people are available to work with you at every step.**

Electricity is the cornerstone of modern life but traditional methods of generating it—using coal, oil, natural gas, and nuclear—often threaten the environment, are scarce, or are not economic. Clearly, there was a need for a new way, a better way.

Texaco has now bridged the technology gap by perfecting The Texaco Coal Gasification Process. This is a method of using coal—the world's most abundant energy resource—to generate electricity cleanly, efficiently and economically. When linked to a combined cycle turbine system, Texaco coal gasification is the best way to generate electricity today and in the future.

Here are some of the reasons why Texaco coal gasification is gaining widespread acceptance and recognition for electric power generation:

Performance • Texaco gasification works. Commercial Texaco gasification plants using solid, liquid and gaseous fuels have operated for years at some 90 locations around the world, reliably producing synthesis gas for chemical feedstocks and electricity.

Fuel • Coal guarantees an adequate and secure supply of fuel throughout the plant's life.

Environment • There's just no cleaner method of using coal. Texaco coal gasification sets new standards for air, water and solid waste emissions.

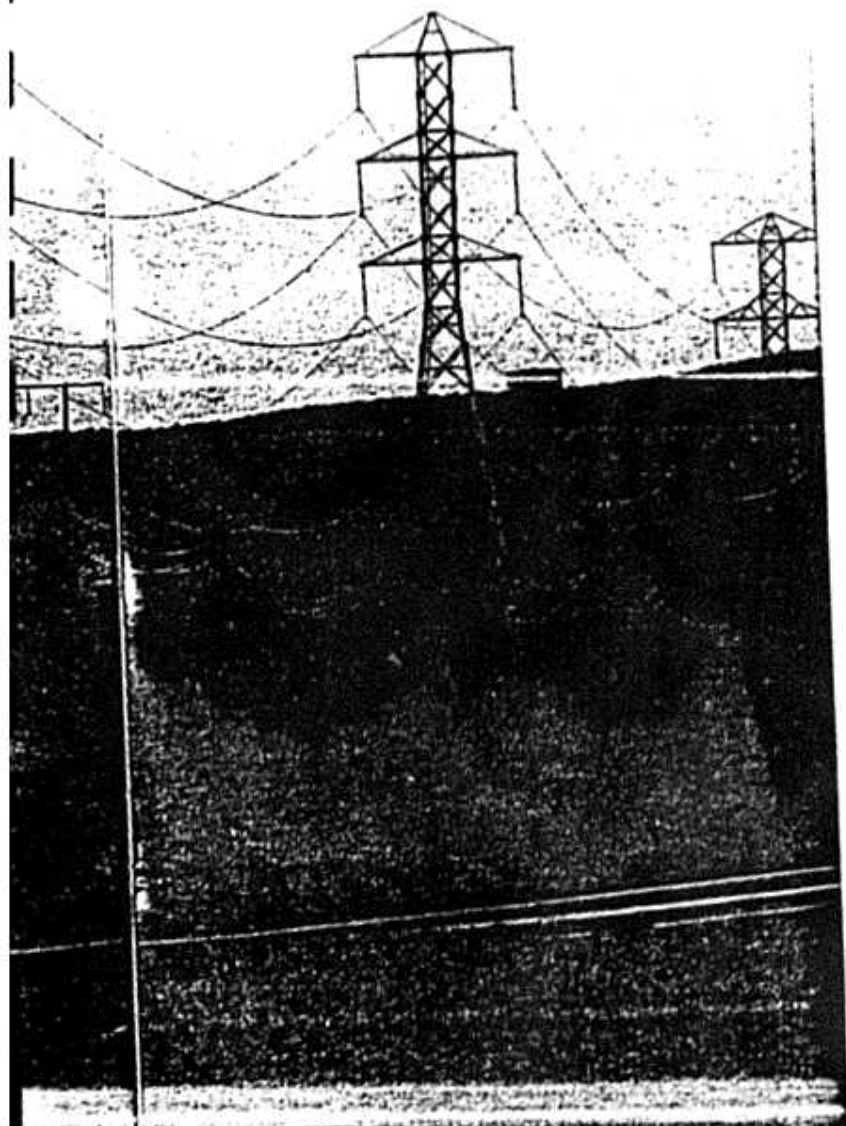
Efficiency • Texaco gasification is an efficient alternative for conversion of coal to clean electrical energy.

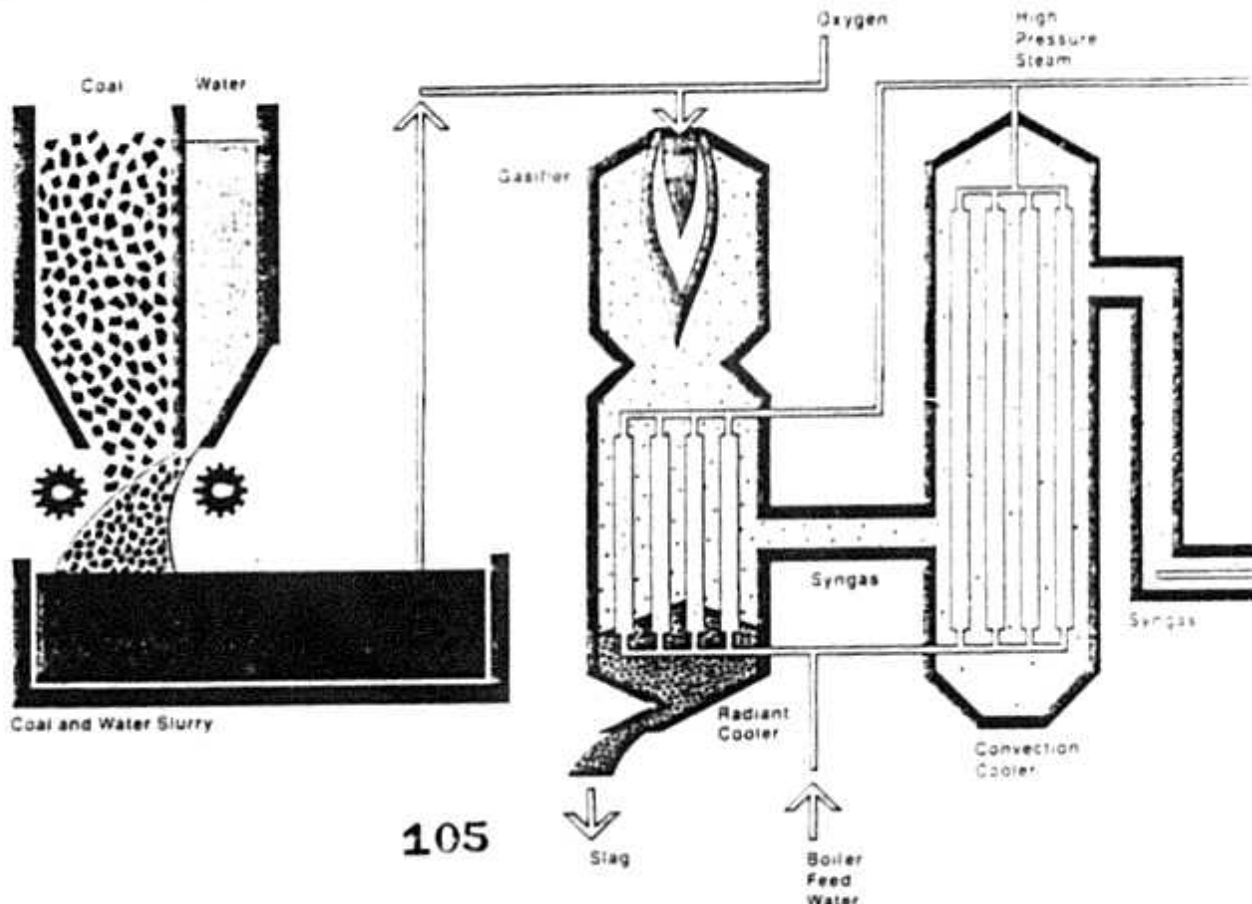
Economics • The many advantages of Texaco gasification are even more attractive when combined with a price tag that's competitive with other power generation systems.

•Texaco Coal Gasification

•Tomorrow's Technology

•Commercially Proven and Available Today





105

IGCC stands for Integrated Gasification Combined Cycle. It represents a marriage of two technologies: coal gasification and combined cycle power generation. The gasification plant converts coal into synthesis gas. That gas is then used by the combined cycle plant to produce electricity. Synthesis gas or "syngas" is mainly carbon monoxide and hydrogen. Texaco gasification is now widely recognized as the preferred way to generate electricity and many other products.

PROCESS DESCRIPTION

A coal/water mixture is ground, using a wet grinding process, to produce slurry. The slurry is fed into a refractory lined gasifier and combined with oxygen, where the coal is converted into syngas, a medium BTU fuel with a heating

The gas is cooled and cleaned of particulates and sulfur in an integrated gasification combined cycle plant. The clean syngas is used in a combined cycle turbine system (gas turbine, heat recovery steam generator and steam turbine).

Coal Handling and Slurry Preparation

A wide range of coals can be gasified. Coal is received and ground with water by conventional grinding mills to produce slurry concentrations greater than 65 percent coal (by weight). Since slurry systems are safer and more easily controllable than dry feed systems, on-stream time is enhanced—an important economic consideration.

Gasification

The gasifier operates at high temperature and pressure (approximately 2,500

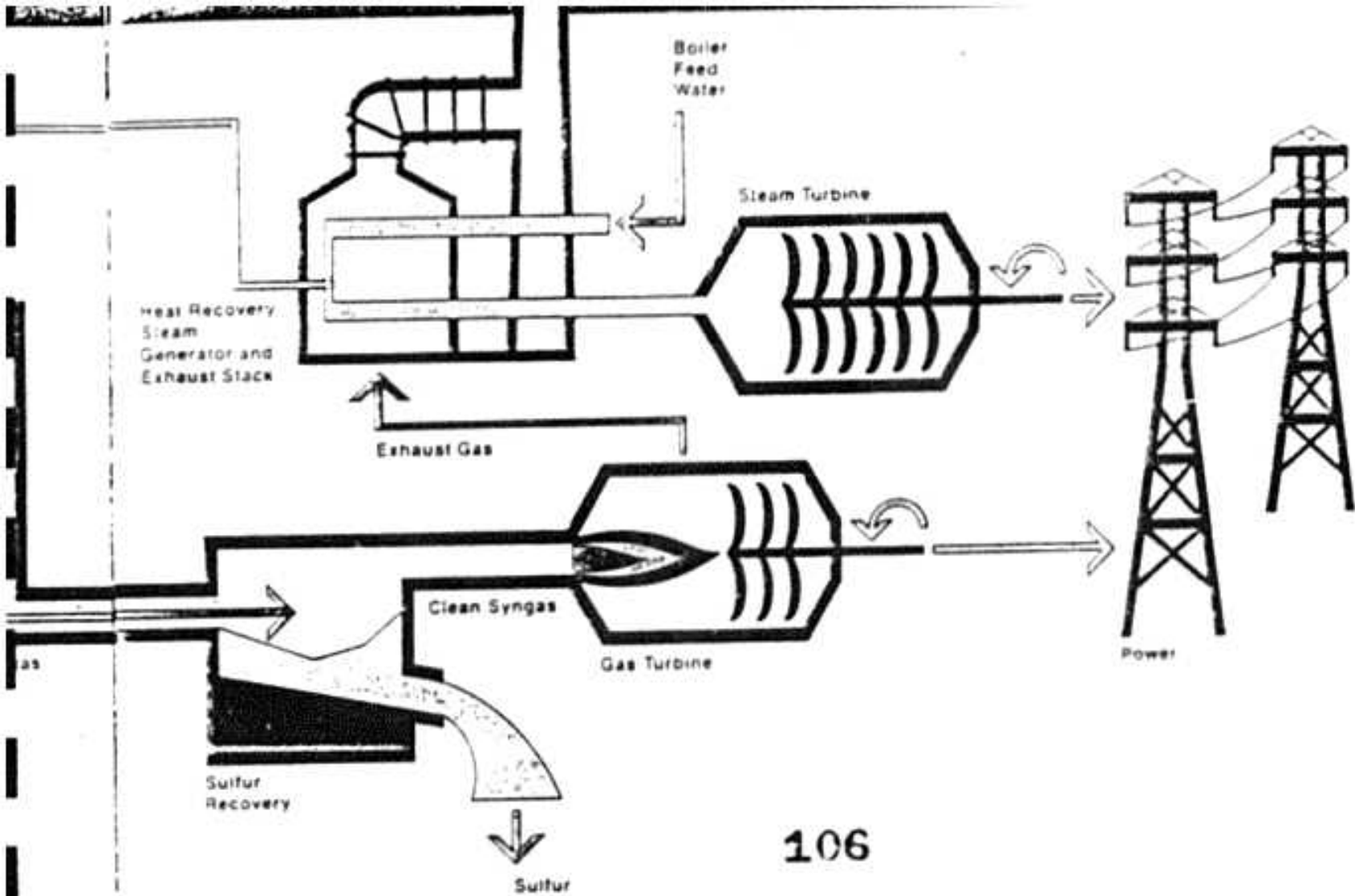
degrees Fahrenheit and high pressure in the range of 500 to 900 PSIA). The temperature is generally established by the properties of the coal; the pressure by syngas end use. The process does not require catalysts. The size of the gasifier vessel is relatively small and it has no internal moving parts. This engineering design pays handsomely by increasing reliability while reducing maintenance.

Gas Cooling/Heat Recovery

The syngas is cooled from 2,500 degrees Fahrenheit to ambient temperature for sulfur removal. There are several ways this can be accomplished.

For combined cycle electric power production, the gas cooling system normally includes two boiler vessels as shown above: radiant and convection coolers. This heat recovery

117



ARTICLE XXXII — ADDITIONAL PARTICIPANT RESPONSIBILITY

The Participant, as signatory to this Cooperative Agreement, covenants with the Government that it will act reasonably and prudently in order to fulfill its obligations under this Cooperative Agreement, including Article XVII and XXV thereof, and under the Repayment Agreement. In the event that the management of the Participant becomes aware of actions or other events that materially and adversely jeopardize the Participant's ability or willingness to continue the Project in accordance with the Cooperative Agreement, the Participant will promptly notify DOE of such actions or other events and of Participant's proposed actions in response thereto. Participant will not undertake or implement those actions unless and until the Contracting Officer has been given the opportunity to attempt to persuade the Participant to mitigate or alter those proposed actions, provided, however, that Participant's obligations under this Article XXXII shall not affect its rights under the other provisions of the Cooperative Agreement to act in response to those actions or other events as Participant determines to be appropriate.

ARTICLE XXXIII — SEVERABILITY

If a court of competent jurisdiction or the DOE Financial Assistance Appeals Board determines that any part of this Cooperative Agreement is invalid, void, unenforceable, or inconsistent with any applicable Federal statute or regulation, such part shall be deemed to have been amended or deleted to conform to such determination.

The Cool Water Program and the Texaco process have been the recipients of awards from American Society of Mechanical

Engineers, Institute for the Advancement of Engineering, Chemical Engineering Magazine, and Power Magazine.

The Cool Water Coal Gasification plant, located in the Mojave Desert, midway between Los Angeles and Las Vegas, has been demonstrating that integrating gasification with a combined cycle power block works on a commercial scale.

Since startup in May 1984, plant performance has been outstanding. Cool Water has been converting 1,000 tons of coal per day to a medium BTU syngas to produce 120 megawatts of electricity. That's enough power to fill the needs of 100,000 homes.

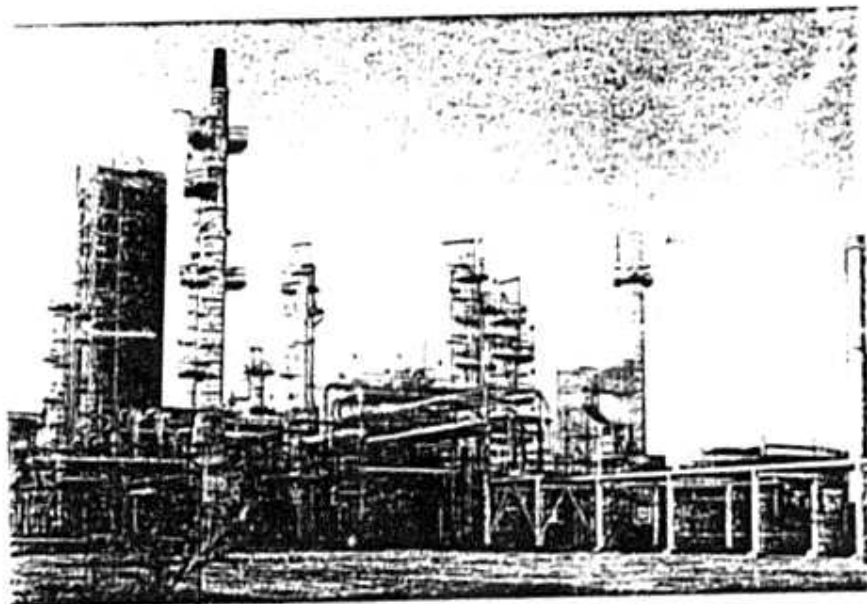
Environmentally, the plant has exceeded expectations. Cool Water is designed to gasify coals with a wide range of sulfur contents. Several types of coal have been run to fully test the process, including a Western coal (SUFCO) with 0.4 percent weight sulfur, Pittsburgh Number 8, an Eastern coal with a 2.9 percent weight sulfur, and Illinois Number 6, a mid-western variety with a 3.0 percent sulfur content. With all three of these coals the process performed remarkably, generating design levels of electricity and removing at least 97 percent of the sulfur.

Cool Water was funded privately by six participants: Texaco Inc., Southern California Edison, The Electric Power Research Institute, Bechtel Power Corp., General Electric and a group of Japanese companies known collectively as the Japan Cool Water Program Partnership (JCWP).

In addition, the Empire State Electric Energy Research Corp. and Sohio Alternate Energy Development Company are contributors to the program. Cool Water was the recipient of the first Synthetic Fuels Corporation award for assistance in the demonstration of this technology.

Cool Water confirms that the Texaco based IGCC process is reliable and is economically competitive with conventional coal-fired plants with scrubbers.

Forward-looking utilities planning new facilities are looking to the Cool Water project as their working model for growth.



▲ Above, syngas after leaving the gasifier is cleaned of particulates and sulfur in the gas cleaning section, then sent to a combined cycle turbine system.

◆ At left, coal is fed to a wet grinding system, then the slurry is pumped to the gasifier, tower.

Texaco's 30 years of experience in gasification have enhanced the operation of today's facilities. The experience being gained by

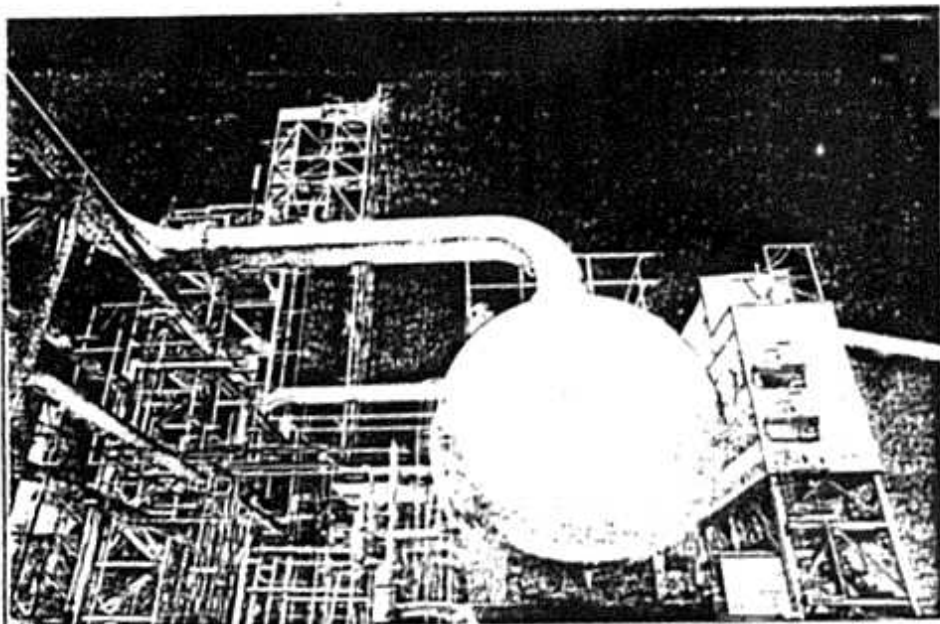
today's commercial units is being incorporated into designs and operating procedures for future plants.

OPERATING FEATURES

The Texaco Coal Gasification Process is easy to operate, it is reliable, and it has competitive operating costs.

The features detailed below apply to the electric utility industry, but are equally valid for other uses:

- **Heat Rate** A Texaco-based coal gasification plant can be designed to operate at a heat rate of 8,900 BTU per kilowatt hour or lower. This represents a solid 10 percent improvement in efficiency over conventional coal plants.
- **Availability** Experience with commercial coal gasification plants has shown that a Texaco Integrated Gasification Combined Cycle plant has a projected full-load availability of at least 85 percent. This increases to 93 percent with the use of a backup fuel for the combined cycle system.
- **Turndown** Power plants must be able to adjust their output to meet variations in load demand. A Texaco gasification plant responds to these changes with only minor performance penalties. A turndown to 60 percent of gas production trims gasification efficiency by approximately one-half of one percent. Cutting production to 25 percent of capacity means an efficiency cut of less than four percent.
- **Load Following** Cool Water has successfully demonstrated the ability to respond rapidly to load changes. To meet a 20 percent load change, for example, the plant has adjusted its output at a rate of greater than four percent per minute. During load change, gas production is determined by demand from the gas turbine, and the total plant output is set by the plant load-control circuit. Appropriate control features are incorporated in the design, enabling a plant to easily satisfy the load changing requirements of most utilities.
- **Ease of Operation** Properly trained plant personnel routinely handle operations at commercial-scale. Texaco coal gasification plants producing ammonia, chemicals and electricity. Cool Water, with its integration of gasification and combined cycle technology, is run very successfully by utility personnel.
- **Operating Costs** Actual Cool Water operating data, adjusted for plant size (to 375MW) and heat rate differences (to 8,900 BTU/KWH), show operating costs of approximately 2.5 cents per kilowatt hour. Considering that operating costs for comparable new conventional coal plants are typically estimated to be at least 10 percent higher, this means substantial savings for utilities.



Phased construction of an IGCC plant offers several advantages. One of the most prominent is the

ability to use natural gas or fuel oil in the short term, but retain the long term security of a coal based system.

CONSTRUCTION AND CAPITAL COSTS

Having the flexibility to add generating capacity in increments, as needed to match power demand (phased construction), reduces economic risk to utility companies and frees capital for other uses. Texaco gasification plants can grow in stages, enabling the utility to:

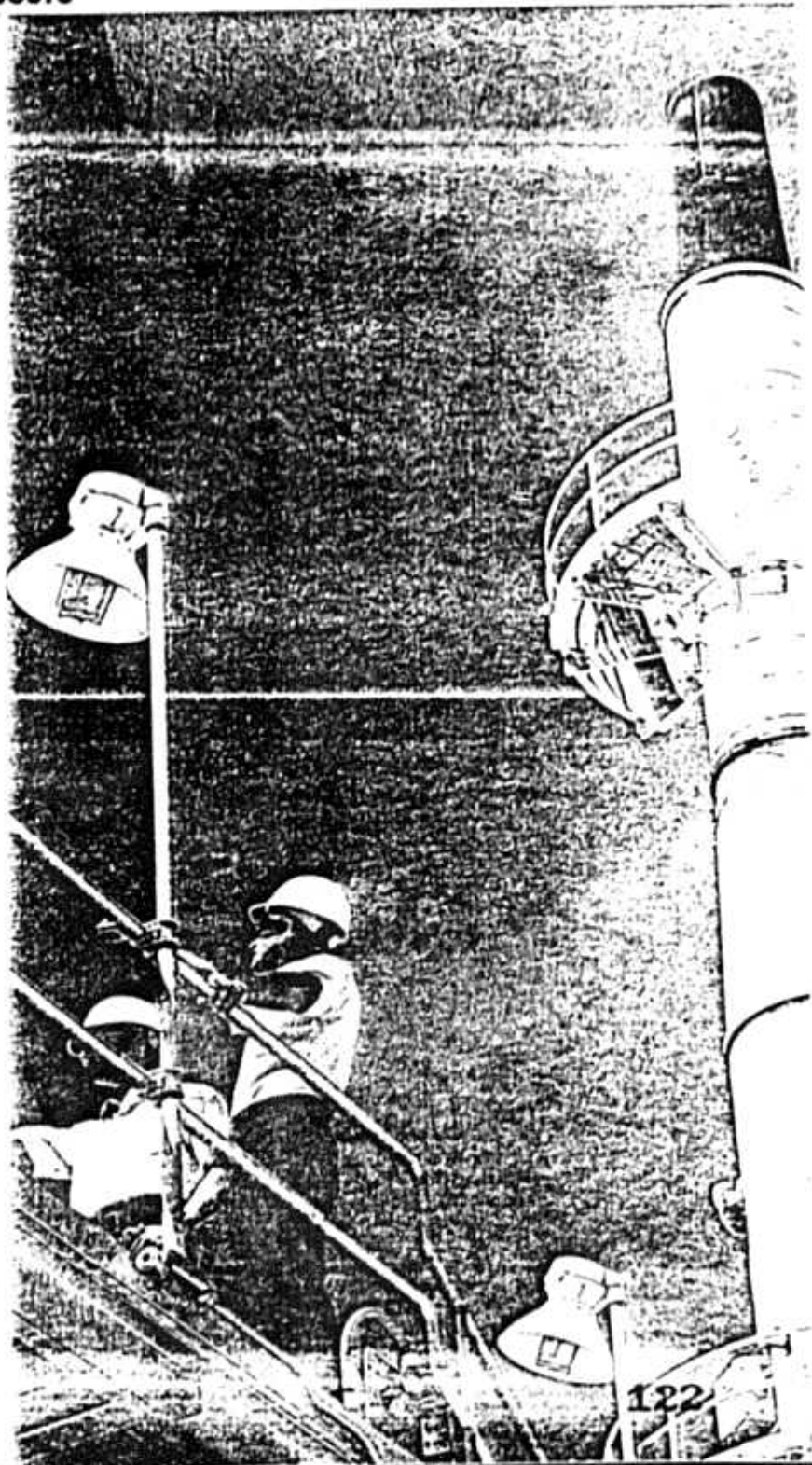
- Increase planning flexibility
- Build in small, efficient increments to match load growth
- Operate initially on liquid or gaseous fuels
- Reduce carrying charges during plant construction
- Reduce dollar commitment risk
- Achieve earlier return on investment

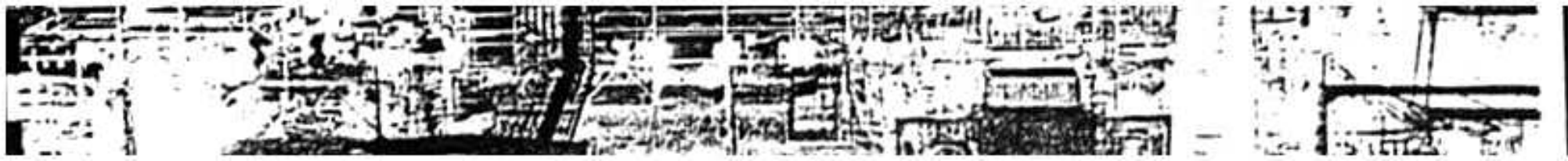
Unlike conventional pulverized coal units, the IGCC's modular construction and operation take advantage of phased construction and allow gradual and cost-effective expansion of power capacity. Combustion turbines for peaking service can be added in stages.

In addition, a combined-cycle facility can be added for intermediate service and then be used as a base-load plant with gasification when fuel prices, availability and/or load demand dictate.

Remember, an IGCC plant can be built for a price comparable to a conventional, coal-fired plant with desulfurization scrubbing units. The capital cost of a 400 MW IGCC plant, excluding an oxygen plant, is about \$1,100 per kilowatt. Oxygen can either be purchased from a third party or can be supplied from a plant owned by the power facility. The capital cost of the oxygen plant is about \$200 per KW.

There's no question that, when coupled with attractive heat rates, lower operating costs and phased construction, the overall capital and operating costs of the Texaco system are very competitive.





Texaco's Montebello Research Laboratory has been the world's leading center for the development of coal gasification. Its

expertise is of great value to the successful operation of all current and future Texaco gasification facilities.

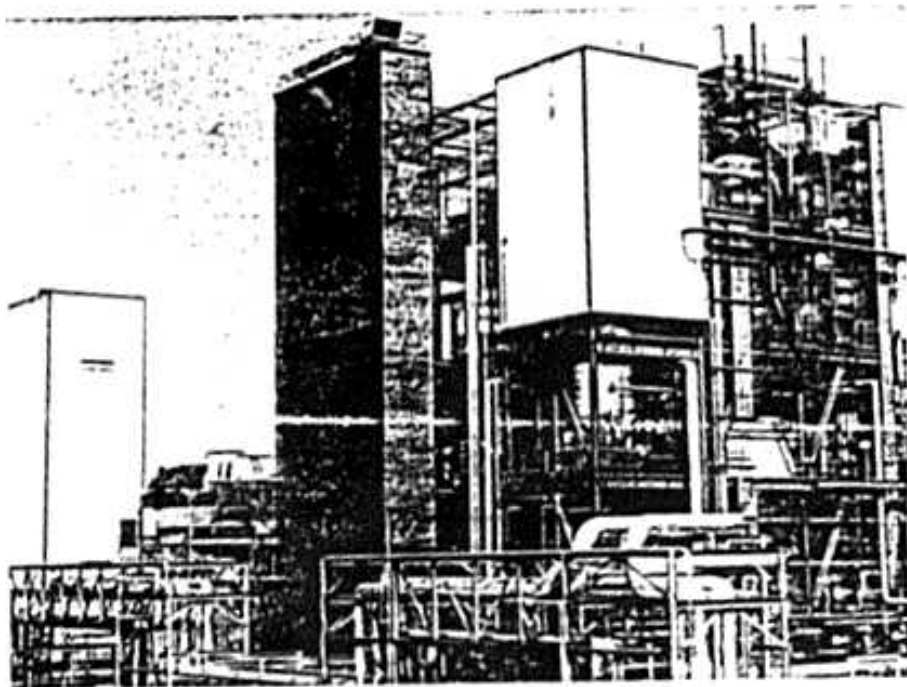
PROCESS IN USE

Cool Water is just one of four full-scale Texaco Coal Gasification plants in commercial operation today. Several more are on the drawing board.

Worldwide, over 90 plants have used Texaco gasification to make syngas from various petroleum feedstocks. Many of the key process components in these plants, such as sulfur removal and recovery equip-

ment, are used routinely in oil refineries and other industries.

Through close involvement in these gasification projects and continuing exchange of technical information, Texaco has gained invaluable operating experience and has enhanced the process design for maximum efficiency. This expertise can now be put to work for you.



The Tennessee Eastman Facility in Kingsport, Tennessee. ▶

Coal gasification is a very versatile technology. It can be used for cogeneration and multi-product "energy park" projects.

Development and Demonstration

Texaco has traditionally been on the cutting edge of technology. The Texaco Coal Gasification Process was pioneered over 40 years ago and has been perfected by advanced research and development. The primary center for this work is Texaco's Montebello Research Laboratory in Montebello, California. Here, three gasifiers ranging in capacity from 15 to 25 tons per day (TPD), are used to make performance evaluations for specific coals and to demonstrate process improvements.

At the time the Texaco gasification process was developed, two demonstration plants were constructed. One, a 160 TPD facility completed by Ruhrchemie A.G. at Oberhausen, West Germany, produced syngas to make chemicals. It served as the design basis for a commercial 600 TPD plant, also located in Germany and completed in 1986. See below.

The second demonstration plant, a 200 TPD facility in Muscle Shoals, Alabama, was built by the Tennessee Valley Authority to produce syngas for ammonia manufacture.

These demonstration facilities helped provide the groundwork for today's commercial plants.

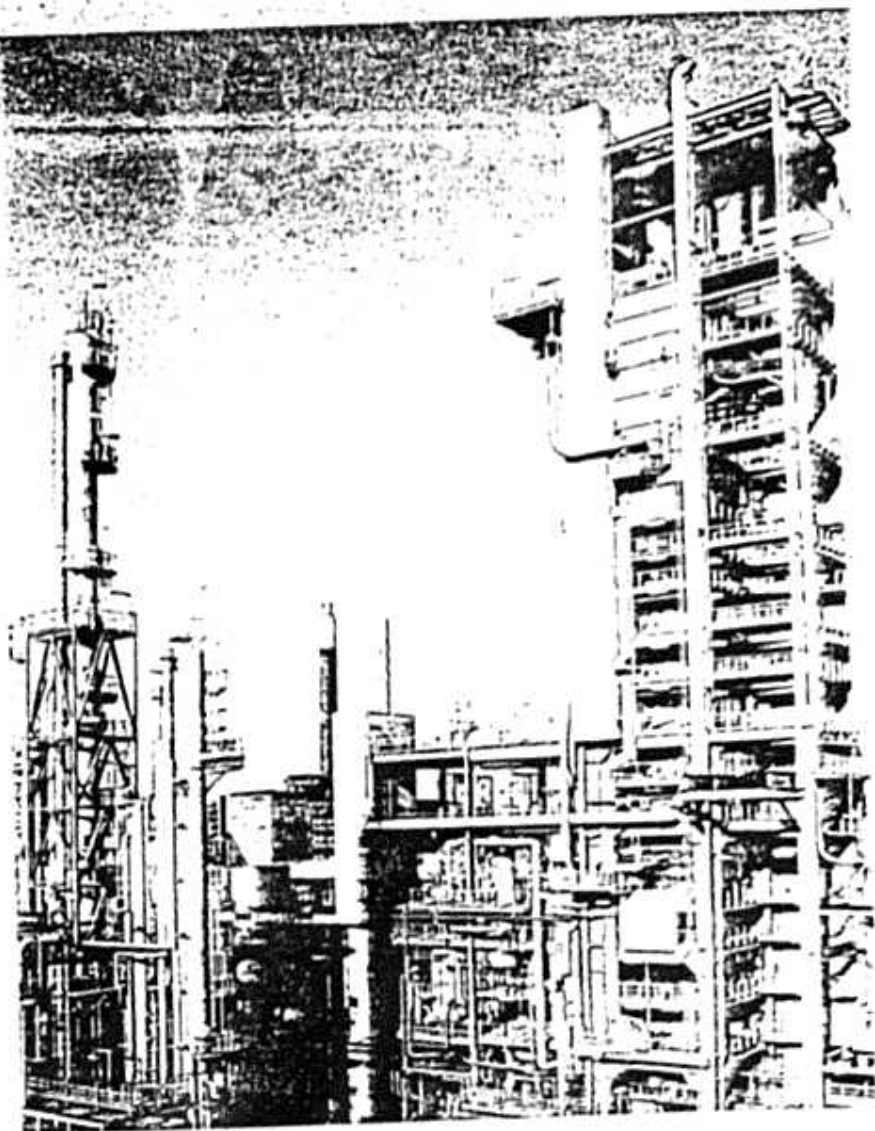
Tennessee Eastman

Tennessee Eastman, a subsidiary of Eastman Kodak, has operated a 900 TPD gasifier at Kingsport, Tennessee since 1963, producing methanol and acetic anhydride. The gasifiers at the facility are shown on the left (top). Its performance has been excellent with an onstream factor of greater than 90 percent.

Tennessee Eastman continues to use coal gasification for a very good reason—it regards it as the best available production method.

Ube Ammonia Industry Co. Inc.

Ube owns and operates a 1,650 TPD Texaco gasification plant in Japan for ammonia production (left bottom). The facility began operations in 1984 and is onstream over 90 percent of time since startup. Ube has run on petroleum coke and has gasified a



variety of coals, including some from South Africa, Australia, and Canada.

Synthesegas Anlage Ruhr (SAR)

In the summer of 1986, an 600 TPD gasification plant began operations at the SAR plant in Oberhausen, West Germany. This plant is near the Ruhrchemie demonstration facility, which proved the soundness of gasification technology to SAR management. SAR produces syngas as a feedstock to make several organic chemicals.

▲ The Synthesegas Anlage Ruhr (SAR) plant in Oberhausen, West Germany

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Texaco has traditionally been on the cutting edge of technology. The Texaco Coal Gasification Process was pioneered over 40 years ago and has been perfected by advanced research and development. The primary center for this work is Texaco's Montebello Research Laboratory in Montebello, California. Here, three gasifiers ranging in capacity from 15 to 25 tons per day (TPD), are used to make performance evaluations for specific coals and to demonstrate process improvements.

At the time the Texaco gasification process was developed, two demonstration plants were constructed. One, a 160 TPD facility completed by Ruhrchemie A.G. at Oberhausen, West Germany, produced syngas to make chemicals. It served as the design basis for a commercial 800 TPD plant, also located in Germany and completed in 1986. See below.

The second demonstration plant, a 200 TPD facility in Muscle Shoals, Alabama, was built by the Tennessee Valley Authority to produce syngas for ammonia manufacture.

These demonstration facilities helped provide the groundwork for today's commercial plants.

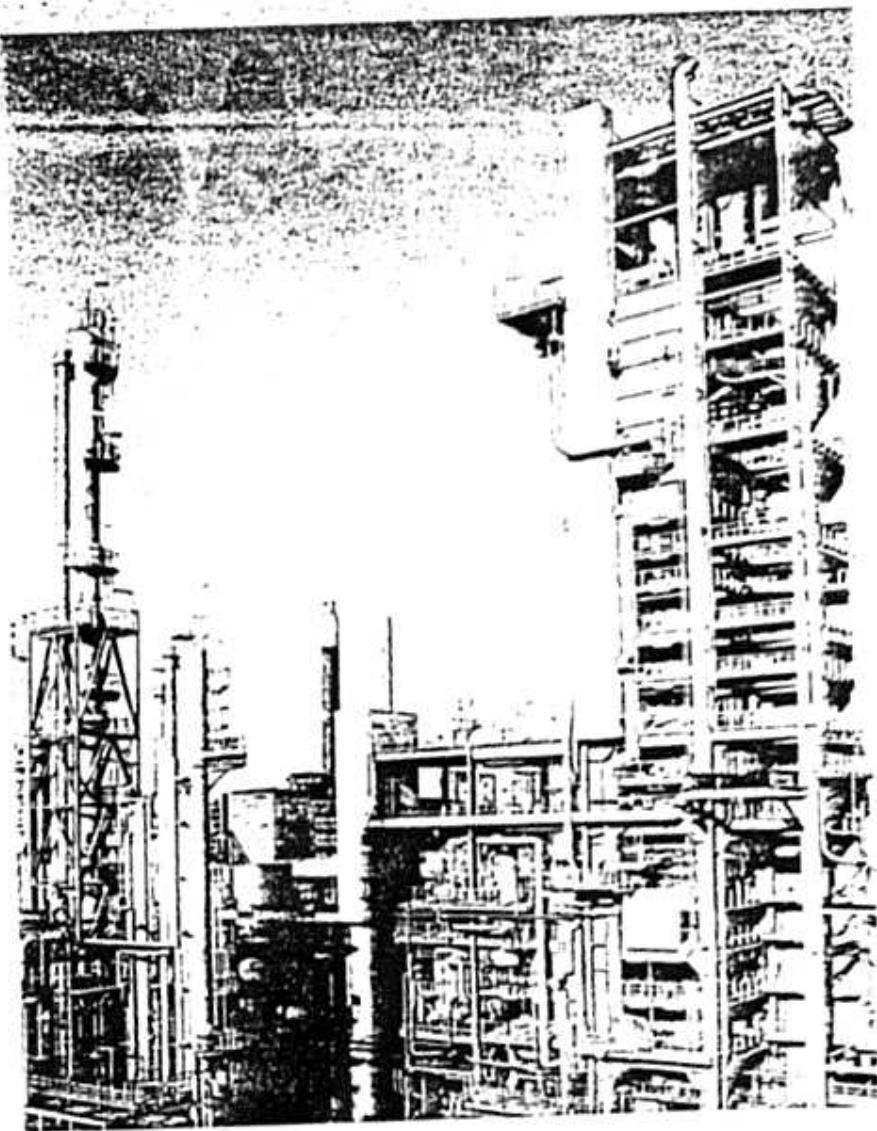
Tennessee Eastman

Tennessee Eastman, a subsidiary of Eastman Kodak, has operated a 900 TPD gasifier at Kingsport, Tennessee since 1963, producing methanol and acetic anhydride. The gasifiers at the facility are shown on the left (top). Its performance has been excellent with an onstream factor of greater than 90 percent.

Tennessee Eastman continues to use coal gasification for a very good reason—it regards it as the best available production method.

Ube Ammonia Industry Co. Inc.

Ube owns and operates a 1,650 TPD Texaco gasification plant in Japan for ammonia production (left bottom). The facility began operations in 1984 and is now onstream over 90 percent of time since startup. Ube has run on petroleum coke and has gasified a



variety of coals, including some from South Africa, Australia, and Canada. **Synthesegas Anlage Ruhr (SAR)** In the summer of 1986, an 800 TPD gasification plant began operations at the SAR plant in Oberhausen, West Germany. This plant is near the Ruhrchemie demonstration facility, which proved the soundness of gasification technology to SAR management. SAR produces syngas as a feedstock to make several organic chemicals.

▲ The Synthesegas Anlage Ruhr (SAR) plant in Oberhausen, West Germany

Texaco has a long standing commitment to the continued development and commercialization of its gasification technology.

TEXACO SERVICES

COOL WATER OPERATING RESULTS - IMPLICATIONS FOR NEW IGCC PLANTS

BY

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PRESENTED AT THE

SIXTH ANNUAL INTERNATIONAL PITTSBURGH COAL CONFERENCE

PITTSBURGH, PENNSYLVANIA
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COOL WATER OPERATING RESULTS - IMPLICATIONS FOR NEW GCC PLANTS

D. H. WATTS, Texaco Syngas Inc., Apple Valley, CA

INTRODUCTION

It is with considerable pleasure that I address this gathering today to discuss the Cool Water Coal Gasification Program's (Program) achievements and to look at future applications of the Texaco Gasification Combined-Cycle (GCC) technology. To understand the current status of our gasification technology, we need to review the history and objectives which led to the creation of Cool Water. Then, I believe, we will have a better understanding of the significance of Cool Water's achievements.

Historically, Texaco began its gasification research in the late 1940's following World War II. Initial efforts involved making syngas from natural gas and oil. At that time, there was some question as to the amount of petroleum reserves and concern for our energy raw materials.

During this period, Texaco began to look at coal as a potential raw material for fuel and chemical manufacture. This led, in the 1950's, to the building of an air blown Texaco gasifier at the Bureau of Mines Center in Morgantown, West Virginia. This facility is now the Morgantown Energy Technology Center. Work on coal gasification stopped after the discovery of large oil reserves in the late 1950's. In the late 1960's, work began again on coal gasification technology. However, during the intervening years, a large number of plants were built based on gas, and oil gasification.

In the 1970's, we examined the energy situation and reviewed technology needs. We concluded that there was going to be a need for coal based technology and that gasification was a technology that could provide a variety of useful and different products. We also concluded that the Texaco Gasification Process (TGP) was an economical and environmentally superior process and that our vast commercial experience in gasification provided a sound basis upon which to move forward.

We further concluded that the generation of electric power using the clean fuel from gasification represented a potentially large market for the TGP. We asked ourselves what would it take to have confidence in a fully integrated gasification power plant to enable investors and utilities to build them. The conclusion was that a full sized commercial demonstration of a fully integrated plant would be required. The existing technologies were integrated and Cool Water was born.

Cool Water is the result of putting together a number of already commercial technologies including coal gasification, combined-cycle power generation, coal handling, and sulfur removal and recovery systems. The new key component of the demonstration was the integration of all these previously existing technologies. The Program's intent was to demonstrate that clean "syngas" could be produced that would be compatible with the demands of a gas turbine and meet the needs of an electric utility as it called for different power outputs. Also, that this could be done by processing a variety of coals. An integrated commercial demonstration would also provide the information necessary for financial investors to have confidence in a commercial plant.

PLANT EQUIPMENT AND PROCESS DESCRIPTION

The major equipment installed at the nominal 122 MW (gross) Cool Water facility includes a coal processing system; an oxygen plant; Texaco 1,200 TPD gasification units with both full heat recovery and quench designs; a sulfur removal and recovery unit; and, a combined-cycle power generation unit consisting of a General Electric Model MS7001E combustion turbine, Heat Recovery Steam Generator (HRSG) and steam turbine.

Figure 1 is an overview of the Cool Water plant. The plant includes all the commercial technologies of coal handling, grinding, oxygen production, power generation, gasification and sulfur removal, brought together in a fully integrated plant.

As indicated in Figure 2, the process begins when coal is wet ground in conventional grinding mills. The ground coal is slurried with water to solids concentrations between 60 to 75%. The coal slurry is safely and reliably pumped to the Texaco gasifier.

There the coal slurry is gasified by mixing it with oxidant in a specially designed burner. Unlike conventional coal combustion processes, the mixture is starved of oxygen and thus only partially oxidized.

By partially oxidizing the coal, mixtures of mostly hydrogen and carbon monoxide - H_2 and CO - are formed instead of carbon dioxide and water vapor - CO_2 and H_2O - that are formed in complete combustion. This predominantly CO and H_2 mixture is called synthesis gas, or more commonly, syngas. Normally, 98 to 99% of the feed coal carbon is converted to syngas.

Unlike conventional coal combustion processes, the Texaco partial oxidation reaction does not produce SO_x or NO_x , two important precursors of acid rain and smog. Instead, the reduced gases H_2S and N_2 are formed.

The gasification reaction also produces no tars, phenols or oils. The solid by-product from the reaction is called slag, a glassy material that has been certified non-hazardous, both by

Federal government standards and in environmentally-conscious California.

In power plant applications, the syngas proceeds to waste heat boilers, called syngas coolers, where high pressure steam is generated. The syngas is then scrubbed with water to remove particulates. The syngas proceeds to the sulfur removal and recovery section where gaseous sulfur components are converted to elemental sulfur, a valuable by-product. The purified syngas is water saturated and routed to a combustion turbine, producing electric power. Exhaust from the combustion turbine is used to superheat the syngas cooler steam which proceeds to a steam turbine where additional power is generated.

TEXACO GASIFICATION EXPERIENCE

The TGP is based on many years of commercial experience. Texaco has licensed over 95 gasification plants, four based on coal. Two coal gasification plants were designed with maximum heat recovery systems and two in the quench mode. Texaco has two gasifiers running in refineries located in Los Angeles and Louisiana. This broad base of experience is what was brought to Cool Water and what Texaco brings today in commercial gasification plants.

Texaco has taken its coal gasification technology through a sequence of steps to minimize risk involved in scaling up as shown in Figure 3. From the days of research, to the unit at Morgantown, West Virginia; through our pilot units in operation in Montebello, California; through demonstration at Tennessee Valley Authority in Alabama, and at Ruhrkohle/Ruhrchemie in West Germany into today's commercial plants at the Ube Industries in Japan; Tennessee Eastman in Tennessee; SAR Unit in Germany; and Cool Water in California, give evidence that the Texaco system is built on a solid commercial base. Further, two units underway in China will add to Texaco's commercial experience.

Figure 4 shows the history and size of the various operating plants using the Texaco Coal Gasification Process. The plants range in size from the 25 TPD pilot units at Montebello to the 1,650 TPD plant at Ube Industries in Japan.

COOL WATER ACCOMPLISHMENTS

Operating Performance

Cool Water gasified over 1.1 million tons of coal from four different feedstocks and produced over 2.7 billion KWH of electric power as indicated in Figure 5. The capacity factor, which is a measure of total plant availability, was about 70% in 1987 and 1988 and 59% overall during the demonstration period. The on-stream factor, which is a measure of gasification plant availability, was 76% in 1988 and 67% overall.

On the surface, these availability numbers appear comparable to conventional power generation technologies. Looking closer, they are actually rather impressive. Cool Water was built as a commercial-scale demonstration plant and was not designed to maximize plant availability.

The plant was designed for single train operation with minimal sparing and did not include backup fuel capability. The test and demonstration nature of Cool Water introduced intentional availability penalties while testing alternate coals, conducting load following tests, demonstrating alternate operating and gasification modes, and performing elaborate environmental monitoring and testing activities in a first-of-a-kind plant.

The addition of multiple trains, sparing and backup fuel capability and the elimination of test and demonstration activities associated with a first-of-a-kind plant will substantially improve availability factors. Availability factors of 85% or higher, depending upon design considerations, are realistic for fully commercial GCC plants.

This data represents only a summary of the operating achievements at Cool Water. All of the individual achievements involving the integration of the technologies, and the individual reliability and operability of all components, are vital to having proven the commercial viability of the technology.

Economics

One of the basic objectives of Cool Water was to develop an economic data base from actual plant operating costs. These actual costs could then be adjusted and used to predict costs for future plants. Texaco initiated a major engineering study in November, 1988, after the selection of a prime contractor, in order to develop optimum integrated gasification plant designs. A number of gasification configurations for the utility industry as well as industrial cogeneration and polygeneration applications were reviewed. The studies indicated that commercial plants can be constructed at capital costs between \$1,450-1,550/KW, obtain levelized COE (mills/KWH) of 48.0-49.3 and achieve attractive dispatch costs less than 19 mills/KWH. The study scope was limited to consideration of technologies which are commercially available today and did not include potential gasification technology enhancements such as hot gas cleanup systems and gasifier in situ sulfur removal which offer the potential for further enhancing Texaco's technology in the future.

Alternate Gasification Modes

At Cool Water, Texaco demonstrated both maximum heat recovery and quench (non-heat recovery) gasification designs. The successful demonstration of both modes will allow utilities design alternatives in producing low cost electric power.

If the gasification system were designed for maximum heat recovery, a radiant/convective syngas cooler configuration would be selected. Plant heat rates of 8,900 Btu/KWH or lower can be achieved at capital costs approximately \$1,540/KW. If cost is of primary concern, the gasification section should be designed based on a quench system with no syngas coolers. The capital cost for such a plant would be \$1,450/KW with a net heat rate of 9,400 Btu/KWH. Perhaps the best compromise between maximum heat recovery and low capital cost configurations is a radiant only syngas cooler configuration. The capital cost for a radiant only configuration would be \$1,510/KW with a net heat rate of 9,100 Btu/KWH.

Load Change Capabilities

Dynamic load following tests have been demonstrated at Cool Water. Power output load changes of 50% at a ramp rate of greater than 5% per minute have been achieved. Dynamic load testing has been conducted demonstrating two modes. In the turbine lead mode, the turbine power output is selected and the plant control system automatically adjusts syngas production in the gasification plant by changing slurry and oxygen flow rates. In the gasification lead mode, the syngas production is adjusted and the combined-cycle unit power production is dependent upon the amount of syngas and steam available.

The gasification plant experiences a small turn-down penalty while the overall plant turn-down penalty is typical of that experienced by combined-cycle plants fueled with oil or natural gas. For example, a 70% turn-down in the gasification plant results in a less than 1% loss in gasification efficiency.

Texaco recognizes utility interest in operating power plants in both base load and intermediate duty. GCC technology provides the flexibility to turn down power production during off-peak periods with acceptable performance penalties. GCC technology also provides additional options not possible with conventional technologies. For example, the power plant can be ramped down while continuing to base load the gasification plant. The excess syngas not used for power generation can be converted into valuable products such as methanol. Methanol can be stored and utilized in stationary sources or used as a transportation fuel.

Operating Personnel Qualifications

Before the successful demonstration at Cool Water, there was concern about the level of expertise required to operate GCC plants. A common misconception was that the technology was complicated and would require highly trained engineering and technical personnel to operate. Cool Water proved that utility personnel with conventional power industry experience can be trained to operate GCC plants. Cool Water used Southern California Edison plant operators transferred from conventional

power plants. These plants included nuclear, oil, gas and coal units.

The operators were not hand selected and had the same general education level and experience as operators in conventional plants. The training program was similar to that used to train operators transferring between conventional plants. Plant owners will not require specialized expertise to staff and operate GCC plants. Normal labor pools, hiring practices and basic training programs can be used.

Alternate Coal Flexibility

Four alternate coals were successfully gasified. These include Utah (SUFCO), Illinois No. 6, Pittsburgh No. 8 and Australian (Lemington) coals. The coal qualities and plant performance characteristics are shown in Figure 6. The predominate coal gasified was the Utah (SUFCO) coal because it was the lowest priced coal on a delivered basis.

The ability to gasify a wide range of coals is important. It allows utilities to select the most economic feedstocks based on price and availability without operating penalties. Other flexibility features include on-line switching between different coal feedstocks, and the ability to blend coal with waste streams such as sewage sludge for potential waste-to-energy applications.

Safety Performance

For a first-of-a-kind plant, Cool Water achieved an excellent safety record. During the five-year demonstration, the plant recorded periods of 745 and 1,017 days without a lost time accident. Normal OSHA safeguards were used, and gas monitoring systems for CO and H₂S gases were implemented. Standard utility industry safety training programs and safety procedures were used, with minor site-specific modifications.

It is important to know that GCC technology can be safely operated, has proven safety systems built into the technology, conforms to familiar safety standards and incorporates existing safety training programs.

ENVIRONMENTAL PERFORMANCE

Cool Water demonstrated atmospheric emissions of SO₂, NO_x and particulates at levels 80 to 90% below Federal EPA New Source Performance Standards (NSPS), produced non-hazardous solid by-products (instead of wastes), produced easily treatable wastewater streams and incorporated water conservation process designs. Cool Water has been called the world's cleanest coal-fired power plant.

The atmospheric emissions for alternate coals tested at Cool Water are indicated in Figure 7. Coals with sulfur contents

between 0.4% and 3.1% were tested. The sulfur removal process can be designed to handle high sulfur content coals without appreciably affecting sulfur removal efficiency. Sulfur removal rates of 96 to 98% were achieved for the four alternate coals tested. This characteristic of GCC technology is important because it allows greater flexibility in selecting coal feedstock(s). Benefits could accrue from purchasing lower quality coals that are closer to the plant site, reducing both coal and transportation costs.

The solid by-products produced include high purity elemental sulfur and gasification slag. The by-products are classified as non-hazardous materials. There is no scrubber sludge or fly ash produced with GCC technology. The sulfur is sold and generates a revenue stream instead of a disposal concern. The gasification slag has been identified as a marketable material for use as a light weight aggregate and road base filler material. By-product utilization is an important consideration when evaluating alternative technologies and will become even more important as existing disposal sites close and new sites become more difficult to permit.

Wastewater streams have been thoroughly analyzed and the results show no harmful pollutants. Because of extensive recycling of process water, the wastewater streams are concentrated and are easily treatable in commercial wastewater treatment processes. Texaco demonstrated its proprietary wastewater treatment process in pilot plant operations at Cool Water.

The process water requirements for GCC plants are approximately one-third less than the requirements of conventional steam-based power plants, since more than half the power generated comes from the combustion turbine. The water requirements for the coal gasification process are approximately one-fifth of the total plant consumption. The cooling towers are the primary water consumer. The water conservation feature of GCC technology can be very important depending upon the availability and price of water resources.

As a result of the superior environmental performance demonstrated at Cool Water, we believe the permitting process for future GCC plants can be streamlined. Much of the baseline data generated at Cool Water is available to assist in permitting commercial facilities.

NEW GASIFICATION PLANTS

Today, based on a wealth of experience, Texaco is prepared to design highly efficient, commercial gasification-based power plants. These plants will have heat rates of 8,900-9,400 Btu/KWH and overall plant efficiencies of up to 43.5% (LHV basis) in some current designs; other designs, stressing reduced capital costs, are projected to achieve overall efficiencies of about 40%. These plants will have unmatched environmental performance. We offer a

variety of services, based on client preferences, feasibility studies and complete packages that include design, construction and operations.

Recent development efforts by Texaco have focused on the gasification of certain waste products that would be fed to the gasifier in conjunction with coal or petroleum coke. These include municipal sludges, refinery and chemical plant organic wastes and other waste streams. These types of waste streams are easily disposed of in the gasification process and provide, in most cases, a revenue stream improving overall project economics.

RESOURCES FOR FUTURE PLANTS

During Cool Water's successful operating history, valuable operating data and experience was acquired.

Cool Water implemented a Data Acquisition System (DAS) that monitored and electronically stored information from over 1,000 monitoring points located throughout the plant. This information has allowed accurate analysis and design modifications improving overall plant availability and efficiency. An extensive video, photo and engineering drawing library of all major vessels and equipment at Cool Water has been assembled. A complete collection of Cool Water reports, documents and technical papers has been compiled.

A computer-based simulator has been developed which has the capability to replicate the operation of Cool Water. Present plans are to modify the simulator to model fully commercial multi-train plants.

A test program utilizing metallurgical coupons in major vessels has provided valuable information regarding proper materials selection for future GCC plants.

Texaco has a skilled operating team with experience developed at Cool Water and other Texaco gasification plants throughout the world. This team is available to train operators and assist in plant startups and operations.

Comprehensive operating and safety procedure manuals, vendor lists and equipment specifications have been developed by Texaco based on actual operating experiences at Cool Water and other Texaco gasification facilities.

In construction we have insured that the components can be shop fabricated and shipped to the site instead of requiring on-site fabrication. Our history, including Cool Water, allows us to use our developed inspection criteria. Vessel sizing, erection and plant layout, are areas in which we excel. Indeed our Engineering Department has pioneered plant construction involving the lay-down and prefabrication of components prior to assembly

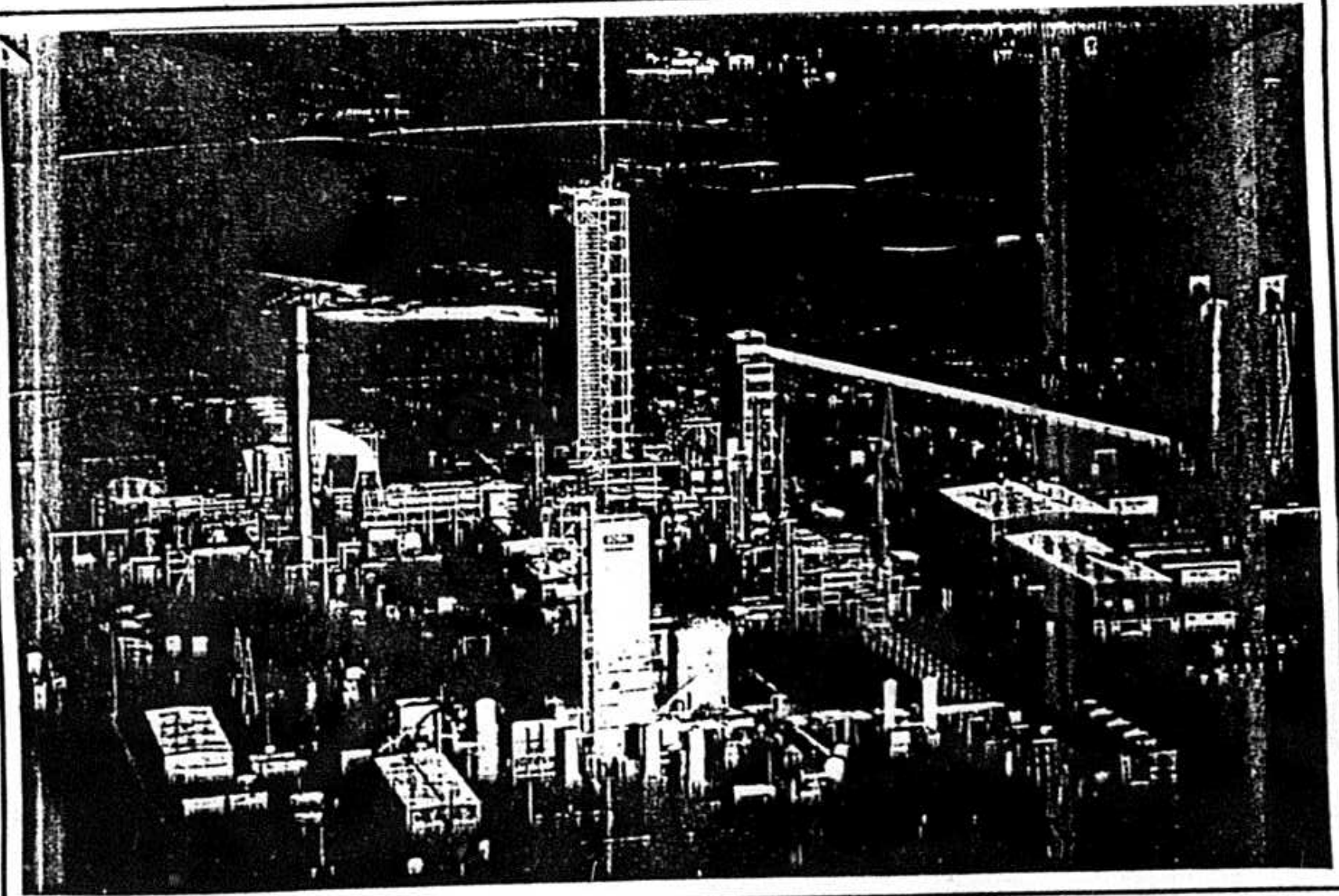
on a construction site. This enables us to minimize construction time and cut costs.

This collection of information, training aids and experience will be available for the design, engineering and construction of Texaco based GCC plants.

CONCLUSION

The Cool Water Program has just completed its highly successful five-year demonstration, provided the final information, know-how and confidence necessary to build commercial Texaco GCC plants and met or exceeded all its objectives.

Texaco is committed to bringing this technology to the market place, with commercial guarantees and long-term customer support. Our intent is to work with the utility and chemical industries to meet their needs for a reliable, cost competitive and environmentally superior technology option.



Texaco Coal Gasification Process History

UBE
TENNESSEE EASTMAN
SAR
COOL WATER

TVA
RUHRKOHL-
RUHRCHEMIE

MONTEBELLO
CALIFORNIA

MORGANTOWN
WEST VIRGINIA

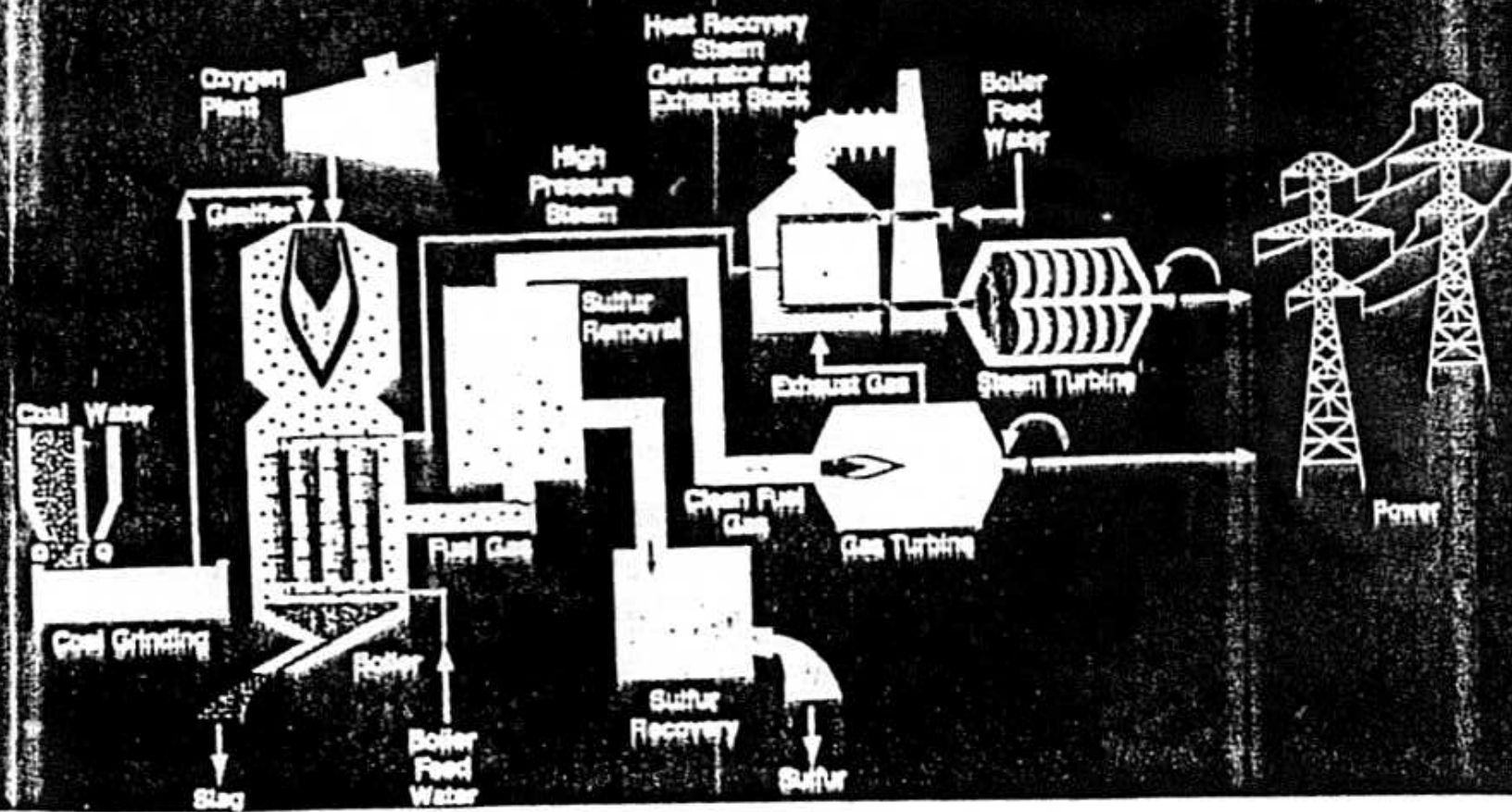
RESEARCH

DEVELOPMENT

DEMONSTRATION

CO

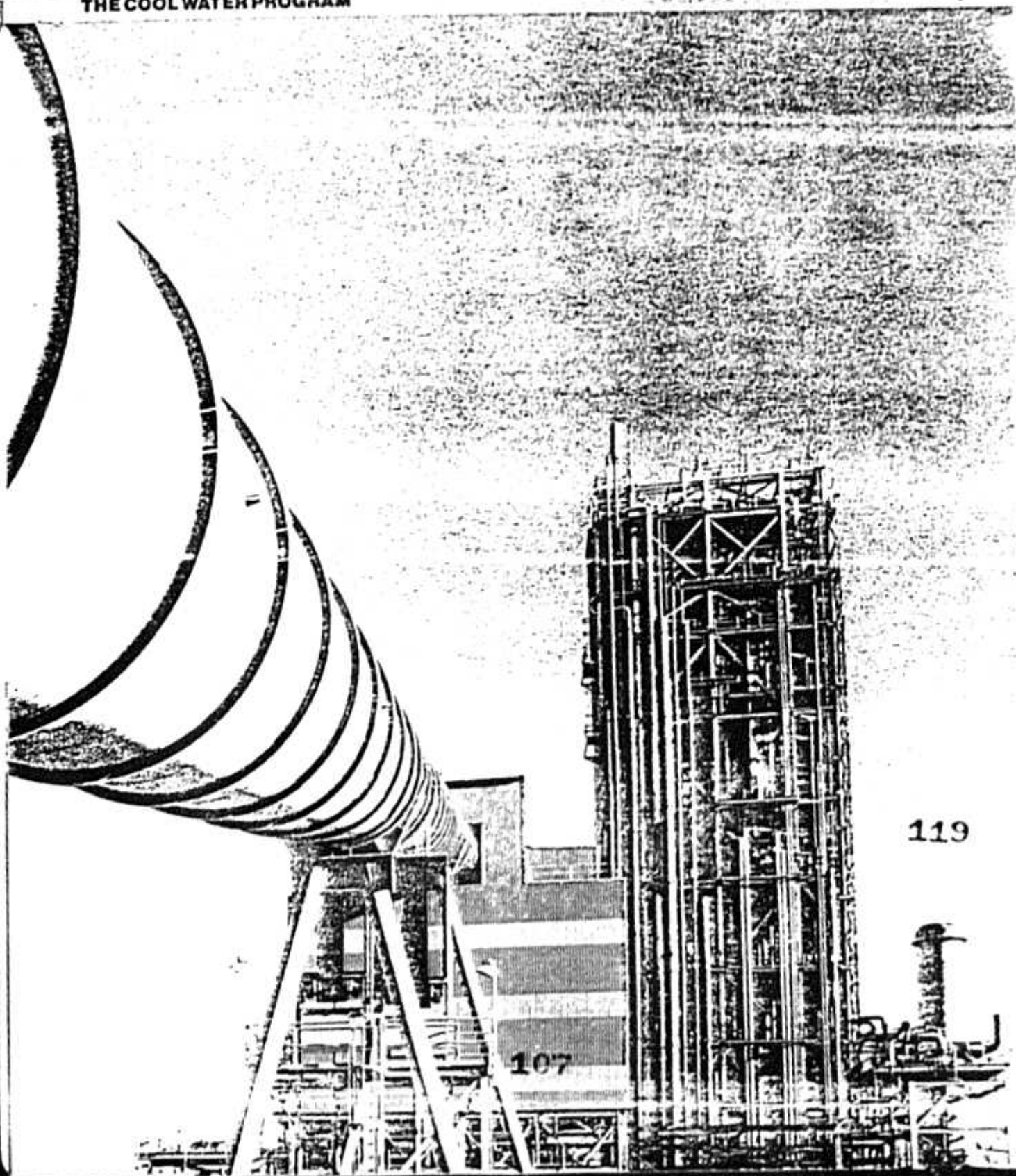
INTEGRATED GASIFICATION COMBINED CYCLE



COOL WATER PRODUCTION SUMMARY

GASIFIER OPERATIONS (HRS.)	1,992	6,648	26,715
COAL GASIFIED (TONS, DRY)	88,767	298,270	1,116,701
GROSS ELECTRICITY FROM SYNGAS (MWH)	205,802	731,260	2,734,717
ONSTREAM FACTOR	87.0%	75.7%	67.4%
CAPACITY FACTOR	76.4%	69.6%	58.7%

THE COOL WATER PROGRAM



119

107

Large Coal Refineries

	SIZE TPD COAL	START-UP DATE
MONTEBELLO	25	1973
RUHRKOHLER/RUHRCHEMIE	165	1978
TENNESSEE VALLEY AUTHORITY	200	1982
TENNESSEE EASTMAN	900	1983
UBE	1,650	1984
COOL WATER	1,000	1984
SAR	770	1986
LUNAN	400	1989
SHOUGANG	1000	1990



PLANT PERFORMANCE/ ALTERNATE FEEDSTOCKS (AT 1000 TPD THROUGHPUT)

	<u>SUFCO</u>	<u>ILL. NO. 6</u>	<u>PITTS. NO. 8</u>	<u>LEMINGTON</u>
HEATING VALUE (Btu/lb) HHV	12,360	12,970	14,100	12,780
SULFUR (%)	0.4	3.1	2.9	0.45
ASH CONTENT (%)	8.8	11.3	7.4	13.4
ASH FUSION TEMP (°F)	2200	2250	2425	2700 +
GROSS POWER PROD. (MW)	116	120	129	119
OVERALL HEAT RATE (Btu/kwh)	10,950	11,700	11,460	10,740

Environmental Performance

LBS/MMBTU

HIGH SULFUR
COAL SO_2

0.076

0.6

LOW SULFUR
COAL SO_2

0.018

0.24

NO_x

0.07

0.6

PARTICULATES

0.008

0.03

COOL WATER ACTUAL DATA

US EPA NEW SOURCE
PERFORMANCE STANDARD



TEXACO
GASIFICATION



GASIFICATION OF SEWAGE SLUDGES

RICHARD B. ZANG, PE

AND M. RASHID KHAN, PhD

TEXACO INC.

AERD

For presentation January 15, 1991 to the
New York Water Pollution Control Association

GASIFICATION OF SEWAGE SLUDGES**RICHARD B. ZANG, PE****AND M. RASHID KHAN, PhD****TEXACO INC.****ALTERNATE ENERGY AND RESOURCES DEPARTMENT****INTRODUCTION**

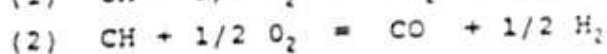
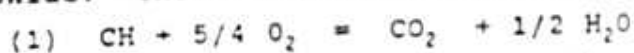
Waste Gasification is an extension of Texaco's conventional fuels gasification technology, in which carbonaceous materials are reacted with a limited amount of oxygen at high temperatures. The partial oxidation of hydrocarbons produces a gas composed primarily of carbon monoxide and hydrogen. The gas, called synthesis gas or syngas, is used both as a feedstock for the production of chemicals such as hydrogen, ammonia, and methanol, and as a clean-burning fuel for power generation. Texaco gasification technology has been used for forty years on feeds such as natural gas, liquid petroleum fractions, coal, and petroleum coke, and is currently licensed in 17 countries for the production of electric power, ammonia and other chemical products. Four commercial coal gasification facilities and 95 petroleum gasification plants have been built.

Sewage Sludge is one of the wastes that can easily be gasified to produce syngas and to ensure the destruction of harmful pollutants. This paper describes the development of the technology to include the disposal and beneficial use of municipal sewage sludge.

For presentation January 15, 1991 to the New York Water Pollution Control Association

PROCESS REACTIONS

The chemistry and thermodynamics of gasification are based on three types of gasification reactions. Equation (1) represents complete combustion of a hydrocarbon, represented by CH, where enough oxygen is supplied to convert all the carbon to carbon dioxide and all the hydrogen to water. The overall reaction is highly exothermic. Equation (2) shows the less exothermic partial oxidation with a limited amount of oxygen. Finally, equation (3) depicts the reaction with steam or water vapor to produce a mixture of hydrogen and carbon monoxide. This reaction is endothermic.



Most gasification processes use a combination of all three reactions in such a manner that external heat or energy does not have to be supplied to the gasifier.

The Texaco Coal Gasification Process (TCGP) yields a medium-Btu gas composed primarily of hydrogen, carbon monoxide, carbon dioxide, and hydrogen sulfide with small amounts of methane. The resulting syngas has a heating value ranging from 280-320 Btu/scf (10,400-11,900 kJ/m³) and can be as high as 500 Btu/scf (18,600 kJ/m³).

Medium-Btu gas is one of the most versatile fuels produced from coal. Many industrial facilities now burning oil or natural gas, and combined-cycle electric power plants and existing gas-based power stations can use this clean burning fuel.

TCGP PROCESS EQUIPMENT

The Texaco Coal Gasification Process uses an entrained bed gasifier with concurrent flow of oxygen and feed, and operates at pressures well above atmospheric, at 350 to 900 psi. It is operated at a temperature above the melting point of the ash in the feed stream, usually above 2400 deg F, which is referred to as operation in the slugging mode. At this temperature, undesirable hydrocarbon

byproducts associated with other gasification processes are not formed. When used to handle hazardous wastes, it is essential that no liquid hydrocarbon streams are formed which could contain residual hazardous materials, or be hazardous themselves.

The Texaco gasifier is a simple refractory-lined pressure vessel into which the feed, in slurry form, is injected at the top through a specially designed burner with a stream of high-purity oxygen. This mixture ignites on contact and reaches temperature of 2500°F in a very short time. The water in the feed slurry serves to moderate the process temperature and participates in the carbon, hydrogen and oxygen reactions. At these high temperatures all the organics are converted to carbon monoxide, hydrogen, carbon dioxide and small amounts of methane. The ash-forming components of the feeds are melted and fused together. Any sulfur is converted to hydrogen sulfide and small amounts of carbonyl sulfide. At the bottom of the gasifier the syngas and slag pass through a pool of water where it is cooled and the slag is solidified to a glassy, non-leaching material. The slag is withdrawn through a lockhopper at the bottom of the gasifier. There are no moving parts in the gasifier.

After leaving the gasifier the syngas passes through a water wash scrubber to remove entrained particulates and then through a cooling train to recover and recycle low grade heat. This system may include a water-gas shift unit to convert most of the carbon monoxide to hydrogen and carbon dioxide via a catalyzed reaction with water and to convert the carbonyl sulfide to hydrogen sulfide. This has several benefits - it enhances overall sulfur recovery levels in the subsequent gas cleanup train, it provides a high temperature source of heat for superheating various low pressure steam flows, and it loads the final syngas product with hydrogen. The combination of these two gases when used as fuel results in very low NOx emissions without the need for water or steam injection. The syngas can be further upgrade to high-purity hydrogen.

The cool syngas is then processed in a sulfur removal unit to extract the hydrogen sulfide and to convert it to elemental high-purity sulfur which is a saleable byproduct. Sulfur recovery levels in excess of 99.5% can be expected. Carbon dioxide can be extracted and liquified for sale to the industrial gas market.

COOL WATER COAL GASIFICATION PROGRAM DAGGETT, CALIFORNIA

A consortium of companies including Texaco completed construction of the Cool Water Coal Gasification Plant in 1984. This 1000 TPD plant is the first commercial, Integrated Coal-Gasification Combined-Cycle (IGCC) power plant in the world.

During its five-year demonstration period, sponsored by the Department of Energy, Cool Water proved that TCCP based IGCC plants could reliably, safely and cleanly produce power from coal. It gasified 1,116,701 tons of Utah, Illinois, Pittsburgh, and Australian coal.

In 26,715 hours of operation, much of it spent in rigorous test and demonstration periods, the plant produced 2,734,717 MW. This is more power generation than the amount produced by all competing gasification-based power plant processes combined.

Before the successful demonstration at Cool Water, there was concern that the technology was complicated and would require highly trained engineering and technical personnel. Cool Water proved that utility personnel with conventional power industry experience can be trained to operate IGCC plants. Cool Water used Southern California Edison plant operators transferred from conventional power plants.

Cool Water demonstrated atmospheric emissions of SO₂, NO_x and particulates at levels 80 to 90% below US EPA New Source Performance Standards, produced non-hazardous, solid byproducts (instead of wastes), produced easily treatable wastewater streams

and incorporated water conserving process designs. Cool Water has been called the world's cleanest coal-fired power plant.

The atmospheric emissions for alternate coals tested at Cool Water are indicated in Figure 1. Coals with sulfur contents between 0.4% and 3.1% were tested. The sulfur removal process can be designed to handle high sulfur content coals without appreciably affecting sulfur removal efficiency. Sulfur removal rates of 96 to 98% were achieved for the four alternate coals tested. This characteristic of IGCC technology is important because it allows greater flexibility in selecting coal feedstocks. Benefits could accrue from purchasing lower quality coals that are closer to the plant site, reducing both coal and transportation costs.

The solid by-products produced include high-purity elemental sulfur and gasification slag. The byproducts are classified as non-hazardous materials. There is no scrubber sludge or fly ash produced with IGCC technology. The sulfur is sold and generates a revenue stream instead of a disposal concern. The gasification slag has been identified as a marketable material of use as a light weight aggregate and road base filler material. Byproduct utilization is an important consideration when evaluating alternative technologies and will become even more important as existing disposal sites close and new sites become more difficult to permit.

Wastewater streams have been thoroughly analyzed and the results show no harmful pollutants. Because of extensive recycling of process water, the wastewater streams are concentrated and are easily treatable in commercial wastewater treatment processes. Texaco demonstrated its proprietary wastewater treatment process in pilot plant operation at Cool Water.

The process water requirements for IGCC plants are approximately one-third less than the requirements of conventional steam-based power plants, since more than half the power generated comes from

the combustion turbine. The water requirements for the coal gasification process are approximately one-fifth of the total plant consumption.

As a result of the superior environmental performance demonstrated at Cool Water, we believe the permitting process for future IGCC plants can be streamlined. Much of the baseline data generated at Cool Water is available to assist in permitting commercial facilities.

COMMERCIAL EXPERIENCE

There are currently three operating, commercial-size TCGP plants. Two more plants are expected to be under construction shortly. These plants are described briefly below.

Prior to the construction of these commercial TCGP units, demonstration units were built and operated by the Tennessee Valley Authority (TVA) in Muscle Shoals, Alabama, and by Ruhrkohle, AG and Ruhrchemie (RAG/RCH) in Oberhausen, Germany.

The 250 TPD RAG/RCH plant operated on coal feed for over 10,000 hours during which new design and materials specifications were developed. Texaco's participation in test runs and data sharing with both TVA and RAG/RCH provided a foundation for the larger commercial design.

TENNESSEE EASTMAN CORPORATION KINGSPORT, TENNESSEE

The Tennessee Eastman Corporation was the first commercially-sized Texaco coal gasification plant. It uses 900 tons per day of coal to produce the hydrogen and carbon monoxide feedstocks for the manufacture of acetic anhydride.

This plant has demonstrated the reliability of the Texaco gasification process by recently completing a twelve month period in which syngas production was interrupted for less

than twenty hours. Gasification plant on stream factors typically exceed 99% here. The plant has gasified nearly two million tons of coal since its startup in 1983.

UBE AMMONIA PLANT

UBE CITY, JAPAN

The Ube plant is the world's first large scale ammonia plant based on coal gasification. The 1650 TPD gasifier produces hydrogen that is fed with nitrogen to the ammonia works.

This plant was constructed in 18 months and was operating at full capacity within its first year of operation in 1984. The Ube gasification plant typically produces on stream factors near 99%.

Over two and one half million tons of feed have been gasified at Ube, including over 200,000 tons of petroleum coke.

SYNTHESGAS ANLAGE RUHR

OBERHAUSEN, GERMANY

The Synthesgas Anlage Ruhr plant was constructed by the same companies that built and operated the demonstration sized RAG/RCH plant described above. This 800 TPD plant was started up in 1986.

The TCGP plant produces a mixture of hydrogen and carbon monoxide that is used to produce oxochemicals - plasticizers, drying agents, and detergents.

SHOUGANG COAL GASIFICATION PROJECT

BEIJING, PEOPLE'S REPUBLIC OF CHINA

The Shougang plant will gasify 1170 TPD of Chinese anthracite to produce fuel gas for an existing steel mill and for town gas. This plant is in its final design phases and is expected to begin its construction phases shortly.

Heat: Waste heat boiler and turbine generator

capital costs with the operating and maintenance costs of the plant. The plant capacity factor is 80%.

The dispatch cost shown includes the cost of fuel, staffing, maintenance materials, start-ups, catalysts and chemicals, and slag disposal. The delivered coal cost is assumed to be \$30/short ton. Sulfur sales are credited at \$60/long ton. Slag disposal cost is assumed to be \$15/short wet ton.

Overall sulfur recovery is in excess of 98%. Total NOx emissions are less than 42 ppmvd (15% O₂).

THE PRIMARY PROCESS ADVANTAGES OF TCGP ARE:

1. Feedstock Flexibility - The gasifier can accept a wide variety of coals and other feedstocks such as petroleum coke, coal liquefaction residues, pyrolysis char, and coke from tar-sands bitumen.
2. High Coal Conversion - Essentially complete coal conversion is attained, either by once-through operation or by recycle.
3. Compatibility With Existing Gas Processing Technology - Conventional systems for scrubbing and sulfur removal are compatible with synthesis gas processing.
4. Wide Range Of Pressures - TCGP is capable of high-pressure operation, which eliminates or minimizes the expense of compression for downstream use in turbines, methanol, methane, or ammonia synthesis processes, and pipeline transportation.
5. High Turn Down Ratio/Fast Load Following - The process and related control systems are normally designed to operate over 60 to 100% of design capacity. The capability of the gasifier to follow load changes with short response times has been verified.
6. Coal/Water Slurry Feed - The water slurry feed system, using high-pressure pumps, is safer and easier to control than dry feed systems.

7. Simple Gasifier Design - Since there are no internal moving mechanical parts within the gasifier, the operability and reliability factors are high.
8. Modular Adaptability - Gasification can be added to existing plants in modules to provide maximum flexibility when incremental capacity is needed.
9. A Clean Fuel Gas - Raw synthesis gas is easily treated at gasifier pressure to remove contaminants before combustion. Entrained particulates are removed from the raw gas to extremely low levels by conventional water scrubbing. Sulfur, primarily as hydrogen sulfide with some carbonyl sulfide, is removed from the gas using commercially available technology which permits recovery as elemental sulfur.
10. Minimal Process Water Effluent Disposal Problems - The bulk of the process water is normally recovered and recycled to the gasification section. The amount of water which must be rejected to recycle water stream is determined by the water-soluble impurities in the specific coal feed.
11. Slag Can Be Recovered - Extensive environmental studies have been conducted on slag samples from the Montebello Pilot Plant. They indicate that the slag leachate does not violate Resource Conservation and Recovery Act Standards.

TEXACO GASIFICATION - PROJECT CONFIGURATIONS

The Texaco Coal Gasification Process when used in an Integrated Gasification Combined Cycle (IGCC) configuration offers a reliable, economical and environmentally-superior option for power generation. Figure 2 shows a simplified flow diagram of a typical IGCC plant. Power production in such a facility can range from 200 MW to 800 MW, with a levelized cost of power of about 5-6 cents/kWh.

Although IGCC is the most likely configuration for utilizing Texaco's gasification technology in power generation, a number of other variations are possible. A once-through methanol process could allow a small percentage of the syngas (5-10%) to be converted to liquid methanol.

Since conventional boilers and fluidized bed boilers produce only steam, the coproduction alternative when using coal as a feedstock is only available for gasification. Methanol could become a valuable product for sale to the transportation sector. There is a high degree of interest in oxygenated fuels, including methanol, across the U.S. due to the new Clean Air Act regulations. Methanol sales could potentially allow a reduction in the price of power sold to utilities. Sales of other high value products, such as argon, could also lower the price of oxygen which would result in a reduction in the cost of power sold.

In addition to the sale of high value products such as hydrogen, exochemicals, and ammonia, there is another way to significantly reduce the price of power waste gasification. Texaco has had an active waste gasification research and development program at its Montebello Research Laboratory for several years. With ever-increasing environmental regulations restricting incineration, ocean disposal and landfills, the waste producers are willing to pay high tipping fees to process these wastes. The opportunities for gasifying wastes are favorable. For a given IGCC plant the predominant feedstock would still be coal but the inclusion of certain wastes at levels of 20-25% of the gasifier feed could substantially lower the price of power.

TEXACO WASTE GASIFICATION

Given the ability of the Texaco Gasification Process to deal with a variety of feedstocks and also its ability to destroy organic and inorganic compounds, TGP is an ideal means of converting waste materials into desirable, useable products. This ability has been documented in published environmental studies which also show the

process effluent water to be free of priority pollutants.

Depending upon the physical and chemical composition of the waste stream, waste can either be used as the primary feed to the gasifier or it can be co-gasified along with a high-Btu feed such as coal. The choice is based on many factors. The feed must be slurried successfully; the heating value of the feed must be such that the gasifier temperatures can be maintained; and the fusion temperature of the ash in the feed must be within operational limits. The ratio of waste feed to primary feed can be adjusted to optimize the gasifier operation. Even if a waste stream can be used as the sole feed to the gasifier, blending of the waste with a primary feedstream allows for continuity and stability of operation.

Once the ratio of waste feed to primary feed has been determined, the two feeds can be blended and injected into the gasifier as a single stream or they can be delivered to the gasifier in two feed systems.

CALIFORNIA DEPARTMENT OF HEALTH SERVICES STUDIES

Under grants from the California Department of Health Services, Texaco successfully demonstrated the gasification of low-Btu, liquid hazardous waste to produce synthesis gas and nonhazardous effluent. The emphasis of the Hazardous Waste Reduction Grant Program is to develop opportunities and technologies to reduce the volume or toxicity of hazardous waste generated within California.

The first grant, awarded in 1986, funded two studies in which the feasibility of gasifying liquid and solid wastes streams was evaluated. The goal of the studies was to identify, sample, and analyze hazardous wastes in order to evaluate their potential as added feedstocks to the gasifier. Due to the low-Btu value of the wastes studied, all were considered as supplemental feeds to a base coal slurry. The liquid and solid wastes studied included aqueous solutions with metals and contaminated soils.

The study concluded that all of the wastes studied could be handled by the Texaco Gasification Process. Only minor modifications to the receiving and handling systems would be necessary. The petroleum industry wastes and the aqueous wastes could be mixed directly with the coal to form pumpable slurries. Wastes such as pesticide rinse water and halogenated solvents could be introduced directly to the gasifier through separate feed systems. The products of the waste gasification would be nonhazardous. The only hydrocarbon in the synthesis gas would be trace amounts of methane. The mineral contents of the waste and the coal would form a nonhazardous slag with an acceptable ash fusion temperature. The slag would be nonhazardous based on the strict California Assessment Manual limits.

Under a second grant from the California DoHS, Texaco demonstrated the pilot plant gasification of low-Btu, petroleum production tank bottoms. In December, 1988, Texaco completed approximately 40 hours of pilot plant operations at the Montebello Laboratory demonstrating the use of this hazardous material as a supplemental feed to the Texaco Coal Gasification Process.

The pilot unit was operated at approximately 2400 deg F and 350 psig. The feed to the pilot unit was approximately 20 wt% hazardous waste (600 lb/hr) and 80 wt% coal slurry (2400 lb/hr). A total of approximately 2500 gallon of petroleum tank bottoms obtained from a California oil production field and approximately 35 tons of coal were gasified.

Analysis of the synthesis gas for operation with the dual feed showed that the only hydrocarbon was methane in very low concentration, less than 300 ppm.

During the pilot unit run samples of solids and waste water were taken and sent to a contract laboratory for analyses for trace organics and priority pollutants. Additional samples of the solids were sent for leachate tests. The solids were found to be

nonhazardous based on the California Assessment Manual limits for total and leachable metals and below the detectable limits in reactive sulfides. Both the solids and the waste water were also found free of trace organics and EPA priority pollutants.

SEWAGE SLUDGE STUDIES

Following the successful testing of hazardous wastes it was felt that gasification might also be appropriate for high-volume, low-hazard wastes such as sewage sludge. Because the pumping characteristics of the slurry is an important consideration, the first sludges tested were Carver-Greenfield sludge from Hyperion, Los Angeles and Zimpro heat-treated sludge from Indio, California. Eighteen-hour test runs were performed with each sludge and coal at Montebello in May, 1989.

The dry Carver-Greenfield sludge was blended directly with a Pittsburgh No. 8 coal slurry. The Zimpro sludge was blended with the coal before grinding to prepare a slurry. The sludges were easily handled and used as-received with no additional treatment.

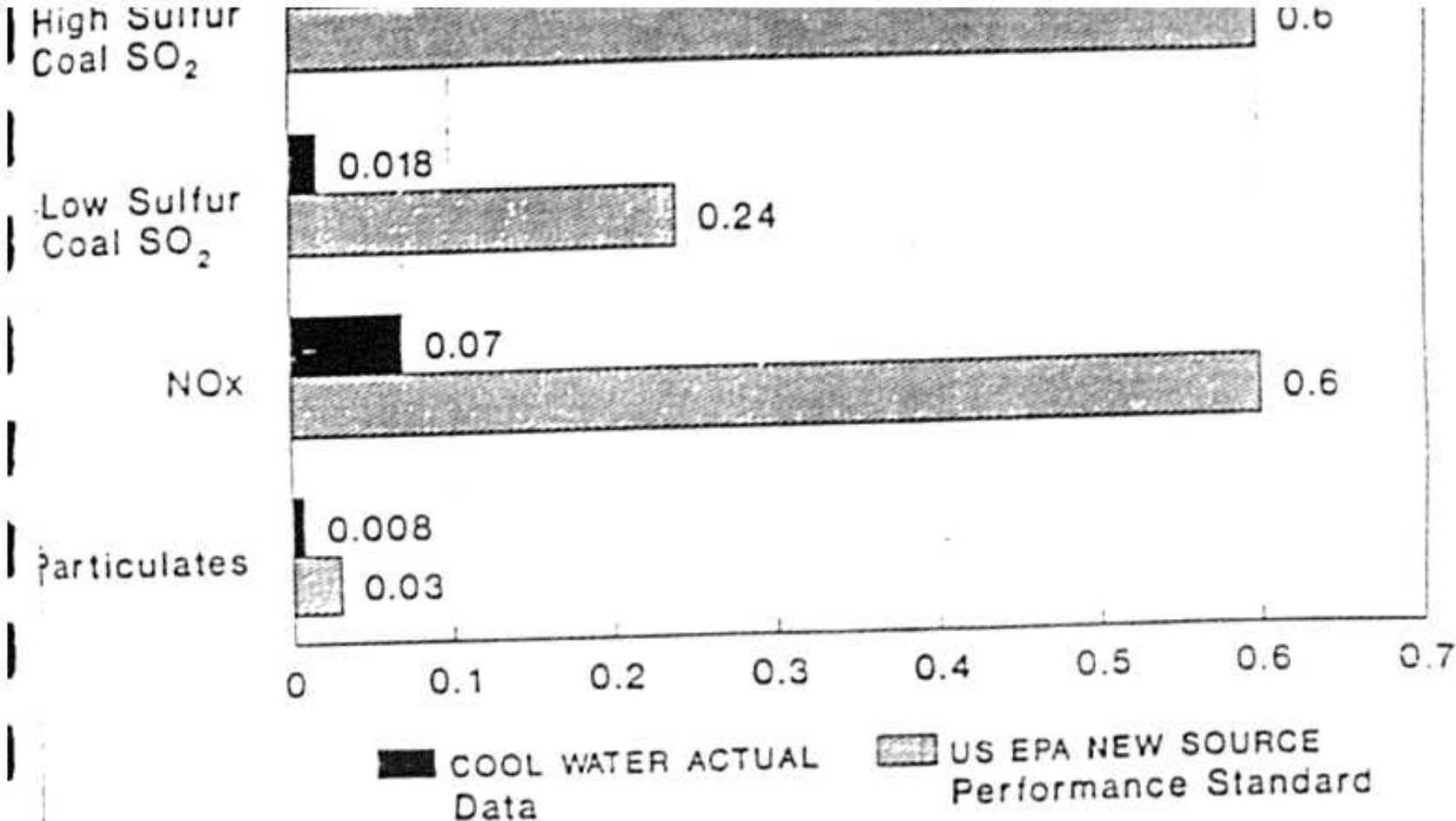
The next efforts were directed at preparing sludges from plants with conventional processing. In order to maintain the highest efficiency in gasification there is a limit to the proportion of water carried in the slurry. The viscosity of drier sludge limits its suitability as a feedstock yet too much water in a less viscous slurry affects the gasifier efficiency.

Bench-scale and pilot tests were run at the Texaco Research Center at Beacon, New York to investigate various techniques to improve the rheological properties of sludge. As a result of this work sludge from the Passaic Valley Sewerage Commissioners in Newark, NJ was dried by indirect steam heating before reslurrying with coal. In December, 1990, twenty-eight tons of this dry sludge was successfully gasified at Montebello. The environmental data collected during this test is now being analyzed

Continuing research is working towards easier methods to prepare sludge for gasification. The combination of sewage sludge and coal is destined to become a common, domestic source of energy.

SCO

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Technology for Energy and the Environment

THE TEXACO
GASIFICATION PROCESS



Gasification

As we approach the close of the 20th century, a major challenge facing people worldwide is finding the energy to sustain economic growth and improve quality of life.

Texaco is leading the way in finding environmentally superior solutions to these challenges, developing groundbreaking methods of converting many types of "dirty" fuels into clean energy using the Texaco Gasification Process. The gasification technology can also be used to convert many forms of consumer and industrial waste into useful products, providing an environmentally safe disposal alternative.

The Technology

The Texaco Gasification Process converts hydrocarbon fuels (such as heavy oil, coal, petroleum coke, Onimulsion[®] and wastes) into a clean-burning synthesis gas, known as Syngas. Rather than burning the fuels (also known as feedstocks) – the conventional method of generating energy – gasification achieves this energy conversion through partial oxidation, significantly reducing emissions of pollutants such as sulfur dioxide (SO_2) and nitrogen oxides (NO_x), which are major contributors to acid rain and smog.

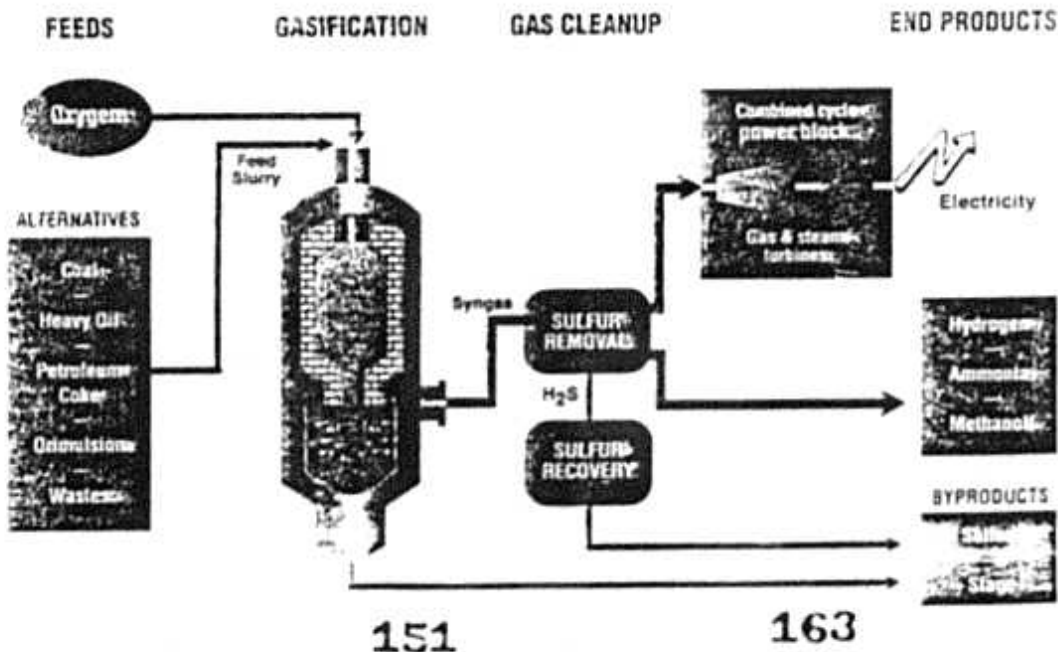
The feedstock – either in a gaseous or fluid state – is injected into the gasifier along with oxygen. In the high temperature ($2,200 - 2,800^\circ\text{F}$), high pressure (400 – 1,200 psi) atmosphere, it is converted into syngas, composed primarily of hydrogen and carbon monoxide, along with carbon dioxide (CO_2) and traces of methane and hydrogen sulfide (H_2S).

Any ash in the feedstock is melted in the process and, when cooled, forms into non-leachable glassy chips known as slag. Heavy metals that exist in the feedstock are encapsulated in the slag. The slag can be safely used for a number of purposes, including cinder blocks, roadbed filler and roofing tiles.

Up to 99 percent of the sulfur present in the syngas can be recovered and sold in an elemental form for fertilizer manufacture. Particulates are removed in the gas cleanup process, leaving a clean gas which is an ideal fuel for generating electricity – much cleaner than burning coal, for example. In addition, syngas has a range of other industrial applications, including the production of hydrogen and other chemicals such as ammonia, methanol and oxochemicals.

Because of its simple design, the Texaco gasifier is both reliable and efficient, and its ability to accept a diversity of feedstocks is a significant – and unique – feature of the Texaco Gasification Process.

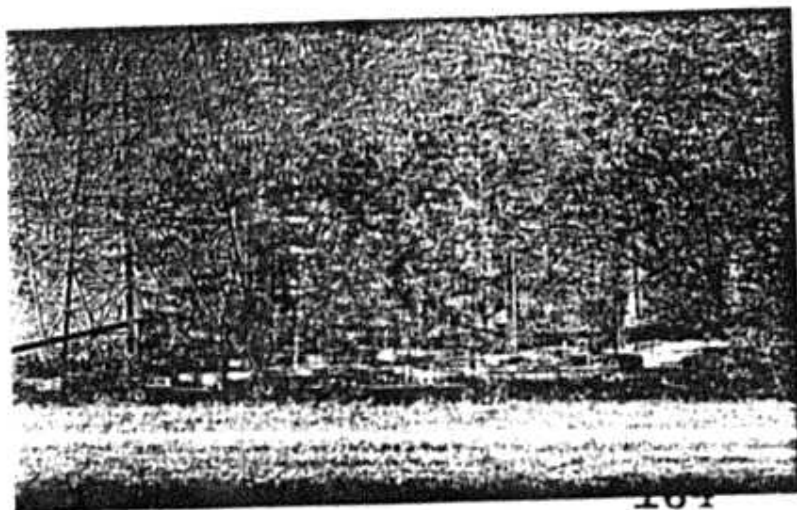
For generating electricity, the Texaco Gasification Process, when integrated with a combined cycle power plant, is environmentally superior to all other systems using the same feedstock.



Fuel Flexibility

Among the most important features of the Texaco Gasification Process is its ability to use many different types of materials as fuels. This makes gasification an attractive technology for a wide range of customers, including utilities, refineries, chemical manufacturers and other industries around the world. Carbonaceous fuels which have been used commercially or demonstrated in Texaco gasifiers include:

- Coal (high- and low-sulfur)
- Heavy oil
- Petroleum coke
- Orimulsion®
- Scrap tires
- Used oil
- Plastics
- Sewage sludge
- Contaminated soil
- Hazardous waste



Currently, more than half the world's electric power is generated from coal as the base fuel. Coal is also an important fuel for the production of chemicals. But increasing environmental concerns demand that cleaner tools be used unless technologies can be developed to use coal in a cleaner and more efficient manner. Texaco's gasification technology offers an environmentally friendly, commercially proven, reliable and efficient alternative to traditional coal-burning methods.

The Cool Water Coal Gasification Program in Southern California was the world's first commercial demonstration of Integrated Gasification Combined Cycle (IGCC) technology, merging the environmentally superior gasification technology with a highly efficient combined cycle power generation system.

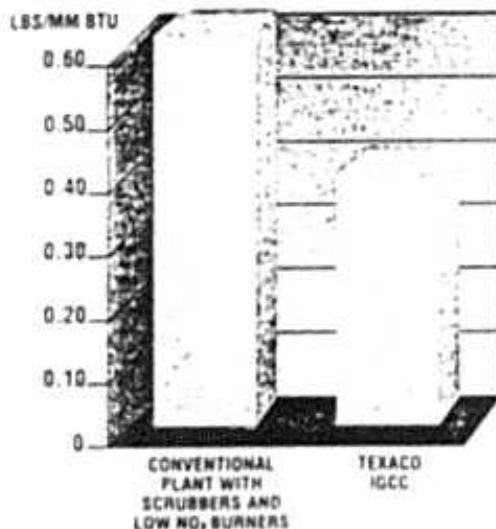
During its planned five-year demonstration (1984-89), the Cool Water plant won numerous environmental awards and was considered the world's cleanest coal-fueled power plant.

Coal gasification plants have been licensed worldwide, including the United States, Europe and Asia. In 1992, the Texaco Gasification Power System was selected for a 200 megawatt coal-fueled power project in Florida.

Texaco gasifiers have proven records of performance, having accumulated more than 200,000 operating hours handling over 5 million tons of various coals with wide ranges of sulfur and ash fusion temperatures.

Another important environmental advantage of the Texaco Gasification Process is its ability to gasify waste materials combined with coal. Coal supplements the heating value of low-Btu wastes, thus improving the efficiency of the waste-to-energy process.

CARBON DIOXIDE EMISSIONS



As a result of its high efficiency, Texaco IGCC emits as much as 23% less carbon dioxide (CO₂) than other coal-burning technologies.

Source: EPR

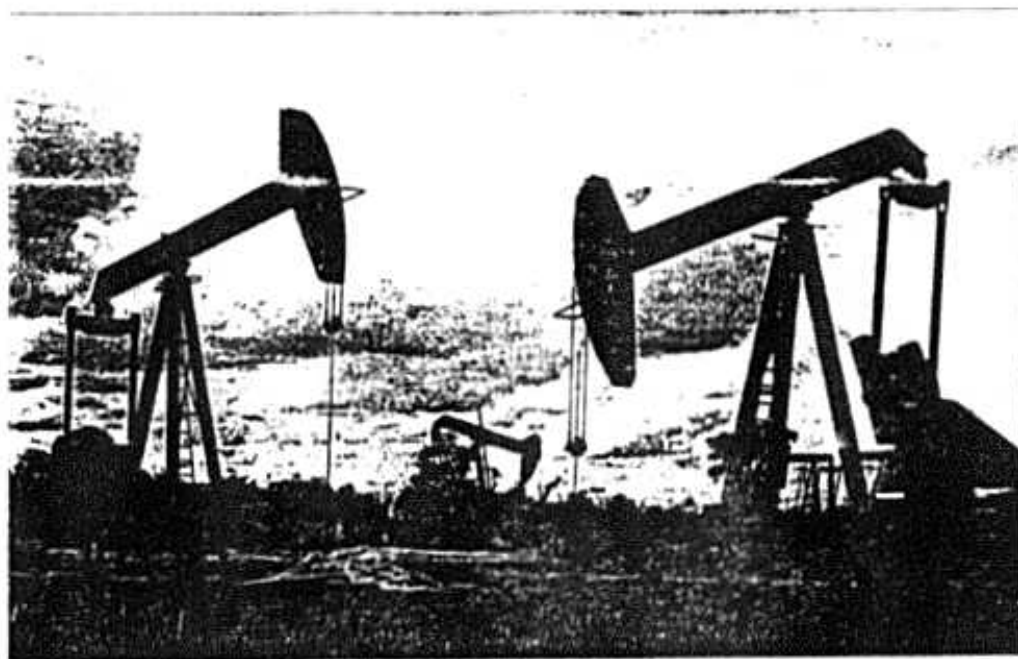
A major concern in international petroleum refining is developing uses for heavy, low-grade crude oils. At the same time, environmental considerations are making it increasingly difficult to market heavy oil residues containing high levels of sulfur and heavy metals.

The Texaco Gasification Process can utilize heavy oil residues as feedstocks to produce clean syngas for electric power generation, hydrogen production, other industrial fuel applications, or for the manufacture of a wide variety of chemicals. In the United States, for example, Texaco gasifiers are used to produce hydrogen from various waste or low-value oils at Texaco refineries.

Meanwhile, gasification of bottom-of-the-barrel residues at refineries in Italy will produce electricity along with hydrogen and steam. Stringent environmental regulations in Europe limit the use of feedstocks such as heavy oil residues for direct combustion, making gasification an ideal technology for this fuel resource.

Unlike other processes, a gasifier does not emit soot or particulates and most process water is recycled.

For heavy oil residues and similar wastes, the Texaco Gasification Process offers an environmentally acceptable alternative to costly waste handling and disposal.



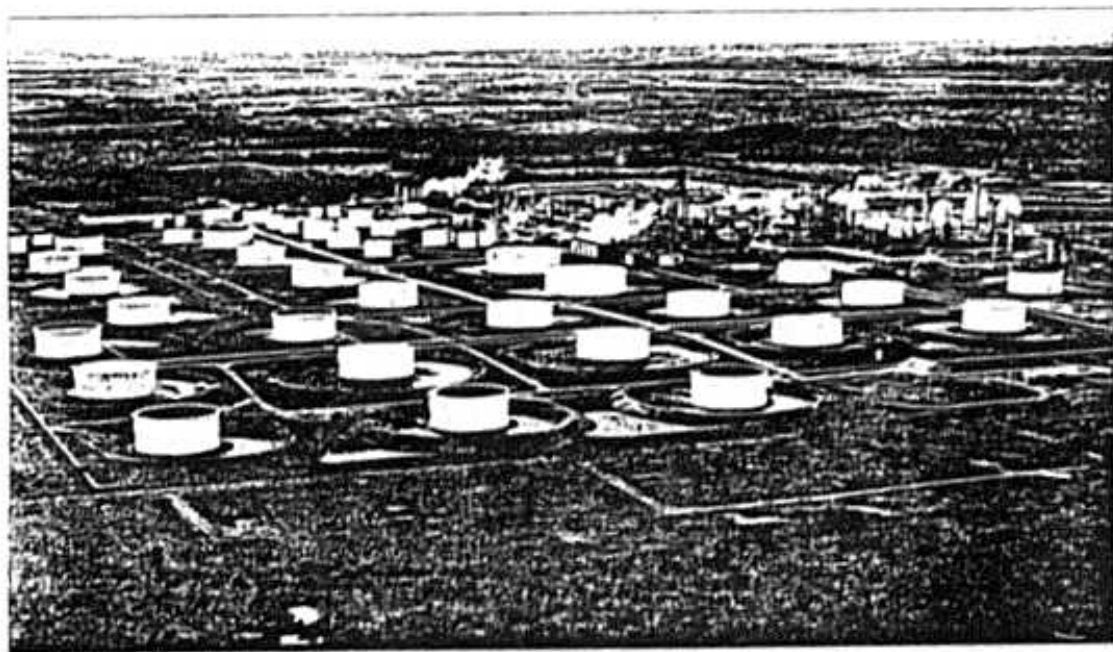
High sulfur heavy oil and heavy oil residues can be safely and efficiently gasified to produce electricity, hydrogen and other products for refining and industrial uses.

Petroleum coke is an oil refinery byproduct with many of the characteristics of coal. It is a solid with a heating value of approximately 13,000 Btu/lb and a sulfur content of up to eight percent. U.S. domestic production of petroleum coke stands at approximately 7,000 tons per day. Most of this is presently shipped overseas to be used as a fuel for conventional boilers. However, when petroleum coke is burned in conventional boilers, it results in significant levels of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) emissions, even when equipped with scrubbers.

Gasification of petroleum coke has been practiced commercially at a large Texaco gasification plant since 1984, and

has been demonstrated to be the clearest method for converting this resource into clean energy. Over 98% of the sulfur in the coke can be captured, converted to elemental sulfur and sold as a valuable byproduct. Emissions of nitrogen oxides (NO_x) and particulates are controlled at extremely low levels, thus both air and solids emissions are significantly reduced.

Texaco gasification plants can be built alongside refineries producing the petroleum coke, thereby converting a onsite to a combination of power and steam for the refinery, and electricity for the surrounding community.



Texaco is developing integrated gasification combined cycle facilities adjacent to refineries to convert petroleum coke into electricity.

With easy handling characteristics and a competitive price structure, Orimulsion® is a new fuel substitute for coal. This fuel, a bitumen-in-water emulsion containing typically 70 percent bitumen and 30 percent water by weight, may be used directly in the Texaco Gasification Process.

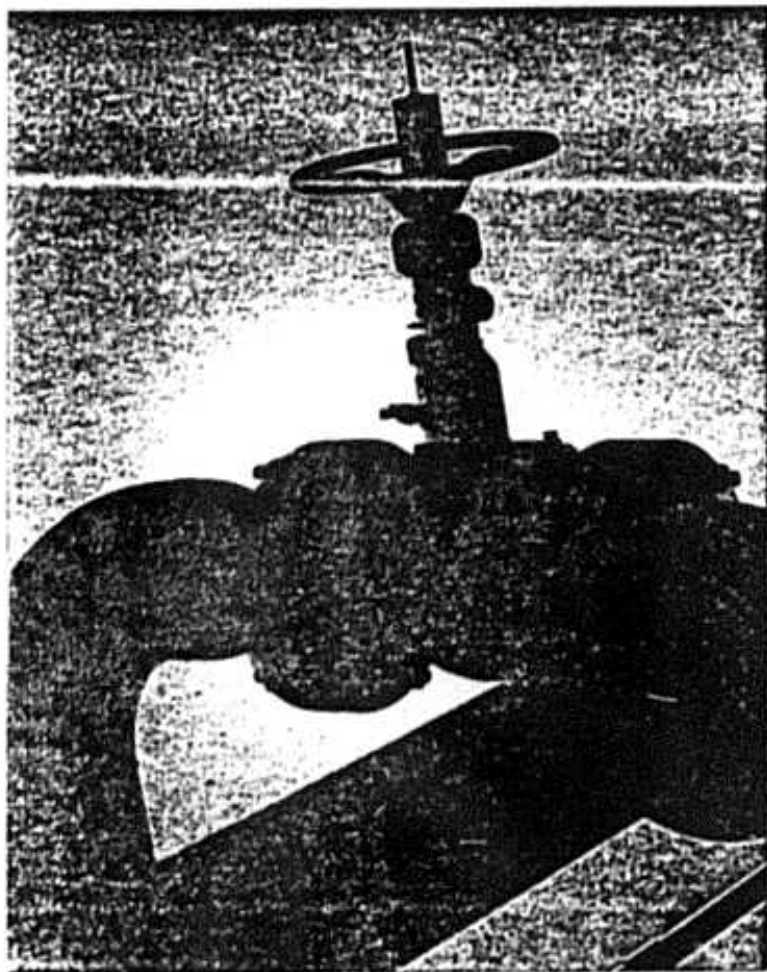
Orimulsion is produced by Bitumenes Orinoco SA (Bitor) of Venezuela. With current technology, some 270 billion barrels are available, making the field approximately equal to Saudi Arabia's proven oil reserves.

Test results have shown that Orimulsion is an excellent feedstock for the Texaco Gasification Process. The water contained in the emulsion serves as a temperature moderator, thus reducing overall water requirements.

Gasification is environmentally superior to other technologies using Orimulsion because sulfur and metal contaminants are removed and captured more efficiently.

Compared with the gasification of typical coal-water slurry feedstocks, Orimulsion gasification results in better thermal efficiencies and higher yields of syngas.

Because of its high energy value and liquid state, Orimulsion is an ideal feedstock for the Texaco Gasification Process.



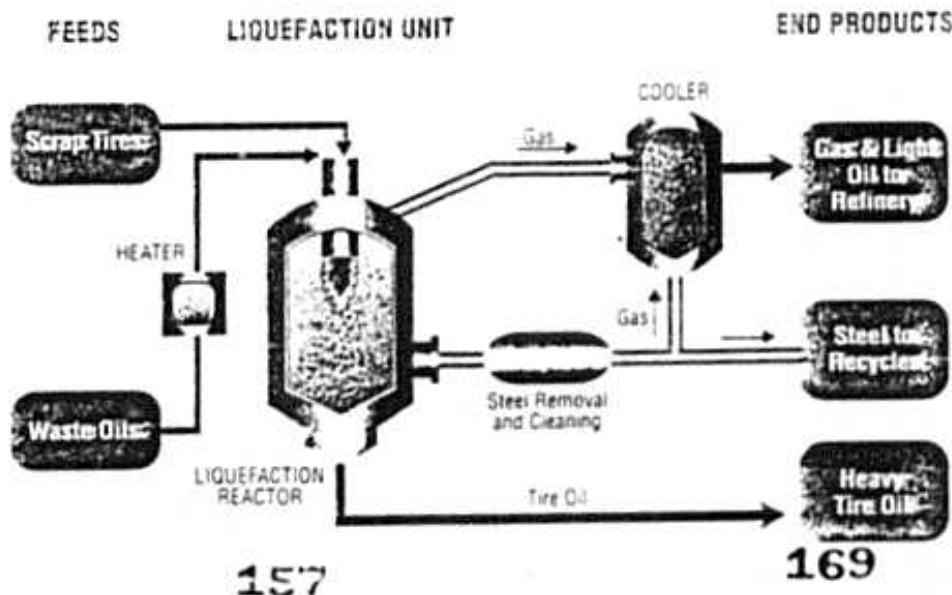


Shredded tires, added to heated used oil, form a tire oil which can be gasified to produce clean syngas for utility and industrial needs.

The disposal and recycling of scrap tires is an important economic and environmental issue in most industrialized countries. In the U.S. alone, as many as 250 million tires are discarded each year, and the majority are dumped in landfills. Equally significant, as many as 400 million gallons of used oil are improperly discarded.

The Texaco Gasification Process, operated together with Texaco's tire liquefaction technology, provides a valuable method of converting scrap tires and used oil into clean energy. A commercial scale tire liquefaction unit has been built at Texaco's Montebello Research Laboratory in California to demonstrate the technical feasibility of the process.

In this unit, shredded tires are added to heated used oil and converted into a liquid stream of Tire Oil. The steel in the tire belts is recovered for recycling. The tire oil, similar to heavy fuel oil, can then be used as a feedstock for the Texaco Gasification Process, or distilled and upgraded into suitable liquid fuels.



Because of their convenience, flexibility and low cost, plastics have become an important part of our society—in packaging, household goods, automobiles and elsewhere in the home and workplace. Unfortunately, because plastics have proven so difficult to recycle, substantial volumes are entering landfills. Since most plastics are non-biodegradable, municipalities and industries are faced with a sizeable environmental challenge.

The Texaco Gasification Process offers a potential option for the beneficial reuse of plastics. Work is

underway to design a commercially viable system of using a wide variety of plastics as a feedstock for the gasifier. Studies show that sulfur, metals and other trace materials can be removed from the gas stream, yielding a clean syngas for the manufacture of chemicals and new plastics. Syngas can also be used to generate electricity.

Among the advantages of plastics gasification is the ability to convert many types of plastics to syngas, including automobile wastes and household plastics. Most sorting of plastics is not required, eliminating a high cost, labor-intensive step.

*Industrial and consumer plastics
can be recycled into clean energy,
industrial chemicals and new
plastics through gasification.*



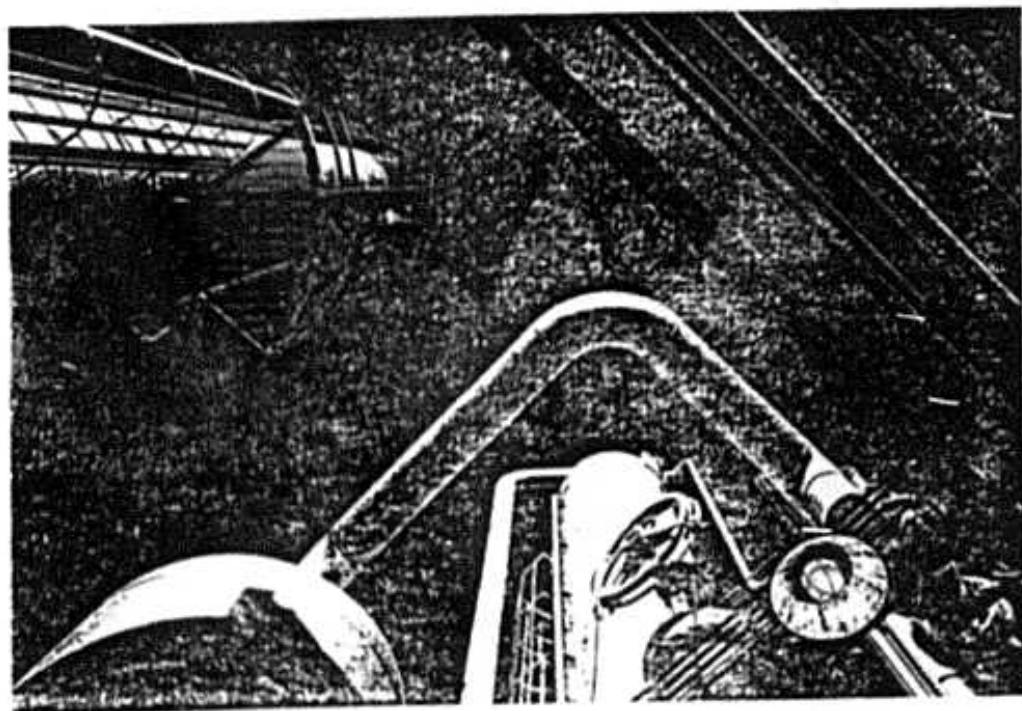
Municipal sewage sludge is among the many carbonaceous wastes that can be gasified to produce clean energy while ensuring the destruction of harmful pollutants. Sludges from California, Texas and New Jersey have been successfully tested with coal, demonstrating that the Texaco gasification process is a viable method of producing energy from this waste material.

Municipalities currently dispose of sludge by incineration or land application. However, incineration is controversial because of limitations on the ability to control emissions of sulfur and metals such as mercury and lead. Land application meanwhile, can often cause unpleasant odors, and there are limitations on its use on farms or parklands.

While typical incinerator exhaust treatment is usually limited to about 90 percent sulfur removal, standard Texaco gasifier designs can remove more than 98 percent of all sulfur. Furthermore, the sulfur recovered in the gasification process is high-purity elemental sulfur with a proven market value. Also, the Texaco Gasification Process destroys hazardous organic materials and pathogens, and heavy metals are contained.

The Texaco Gasification Process presents an environmentally superior alternative to other methods of desludging sewage sludge.

Gasification is preferable to other methods of sewage sludge disposal because it captures metals in a non-leachable slag form, while producing clean syngas.



A pressing environmental concern is the clean-up or remediation of sites where soil and groundwater have been contaminated by chemicals. Complex hydrocarbon and metal-containing compounds often constitute a major class of contaminant found at these sites.

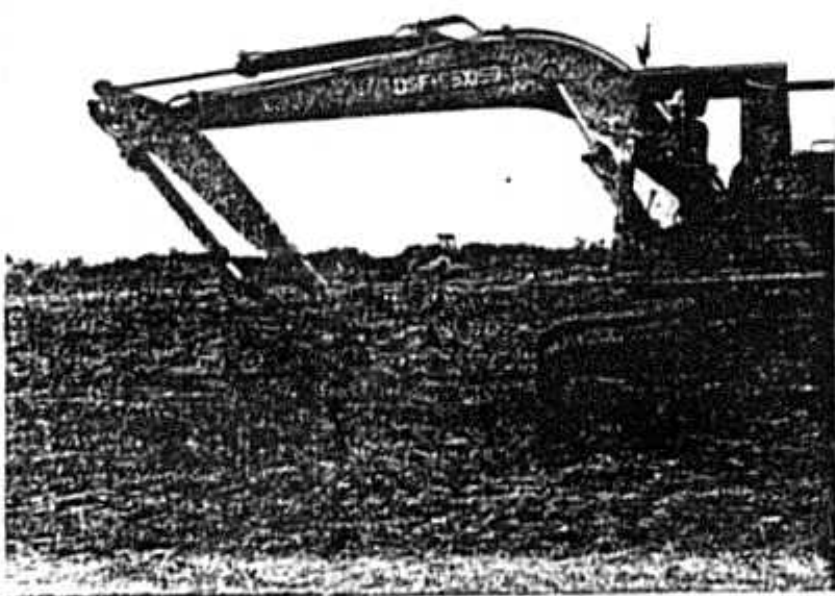
The Texaco Gasification Process can convert contaminated soils to non-hazardous products in an environmentally safe manner. The process converts hydrocarbons into syngas and lesser

amounts of water, carbon dioxide, and methane, while the soil melts at the high process temperatures and, upon cooling, forms a non-leachable slag.

At Texaco's Monterey Research Laboratory in California, gasification tests demonstrated that, using coal as complementary fuel, gasification can convert a low heating value waste into useful syngas and an inert slag. The syngas was essentially free of hydrocarbons and could be purified easily by standard methods.

The success of these tests demonstrates the potential of the Texaco Gasification Process for the destruction of hydrocarbon-contaminated wastes, particularly contaminated soils from waste sites.

When mixed with coal or other high energy feedstocks, contaminated soil can be gasified, eliminating a potentially hazardous waste and producing clean energy.



The ability of the Texaco gasification process to destroy organic compounds and capture metals in non-detachable slag makes it an ideal means to convert waste materials to desirable useable products. The process offers an efficient, acceptable and economic alternative to land disposal or incineration.

The ability of Texaco's technology to process hazardous wastes effectively has been documented in published environmental studies. These studies also show the process effluent water to be free of priority pollutants.

Texaco's Montebello Research Laboratory has worked closely with the California Department of Health Services to identify hazardous wastes that could be feedstocks to the gasification technology.

Depending on the physical and chemical composition of the hazardous waste stream, it can either be used as the

primary feed to the gasifier or it can be gasified along with another feedstock such as coal or low-value oils. In the California studies, due to the low heating value of the wastes involved, all were considered to be supplemental feeds to a base coal slurry. The California studies concluded that all the wastes could be used as feedstock for the Texaco Gasification Process.

An extensive study has been conducted by the U.S. Environmental Protection Agency under its *Subcritical Innovative Technology Evaluation (SITE) Program* to further validate the performance of the Texaco Gasification Process for hazardous wastes.

Hazardous waste can be rendered non-hazardous through gasification: providing a solution to a major environmental problem.



Awards

6

THE FOLLOWING IS A LIST OF AWARDS EARNED BY THE TEXACO COAL GASIFICATION PROCESS AND THE COOL WATER PROGRAM.

1987 ASME ENERGY RESOURCES TECHNOLOGY AWARD.

Presented by the American Society of Mechanical Engineers to Cool Water as the most outstanding example of advancing mechanical engineering in energy resource related technology.

1986 ENERGY INNOVATIONS AWARD.

Presented to Cool Water by the California Energy Commission.

1986 OUTSTANDING ENGINEERING ACHIEVEMENT AWARD.

Presented to Cool Water by the Institute for the Advancement of Engineering. In announcing the award, IAE officials called Cool Water "very possibly the world's cleanest coal using plant."

1985 KIRKPATRICK CHEMICAL ENGINEERING HONOR AWARD.

Awarded to Texaco by Chemical Engineering Magazine. Coal Gasification for Electric Power Production was cited as an excellent example of the diversity of the process.

1985 ENVIRONMENTAL PROTECTION AWARD.

Presented to Cool Water by Power Magazine. This annual award recognizes utility industry achievements in protecting the nation's natural environment.

1984 WALTER FLOWERS ACHIEVEMENT AWARD IN SYNTHETIC FUELS.

Awarded to Texaco by the National Council on Synthetic Fuels Production for Development and Commercialization of the Texaco Coal Gasification Process.

For further information contact:

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White Plains, NY 10650
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Commercial Application of Slag
from
Texaco Coal Gasification Plant
in
Ube Ammonia

By
Kotaro Katagiri
Ube Industries, Ltd.
Tokyo, Japan

Presented At :
IEA Expert-meeting
on
the Use of Coal-gasification Slag

May 10th - 11th, 1990
Arnhem, The Netherlands

Contents

ABSTRACT	1
INTRODUCTION	2
OPERATING EXPERIENCE	3
NEW APPLICATION OF SOLID DISPOSAL	4
LIGHT WEIGHT AGGREGATE	5
CONCLUSION	8
TABLE AND FIGURE	9

ABSTRACT

In Ube Ammonia Industry Co., Ltd., we have a commercial Texaco Coal Gasification Process (TCGP) plant for ammonia manufacturing 1,000 metric tons a day from 1,500 metric tons coal, which started operating, in August, 1984.

Since the beginning of its plant operation, the slag from gasifier has been discharged and utilized as a part of raw material for our cement factory. After intensive research and development work by our cement division, in October, 1987, we started producing a porous light weight aggregate made from the coarse slag from Ube Ammonia and put it on the market in Japan. And we have a feeling there is a great deal of potential market in this field due to the increase of client's demand for our product. Recently, the other utilization of coal gasification slag has been also studied for market research by Ube Ammonia.

In this paper, we present the commercial application of slag from Texaco coal gasification plant in Ube Ammonia.

INTRODUCTION

In 1972, Ube Ammonia Industry Co., Ltd. commenced its operation as an ammonia manufacturer by steam reforming plant using naphtha and later LPG. However, through the experience of the two oil crises in 1973 and 1979, we had to change our strategy heavily dependent on imported petroleum. In order to cope with those energy crises, the world's first large-scale ammonia syngas plant based on the Texaco Coal Gasification Process (TCGP) was completed to replace the existing steam reforming plant in July, 1984. Since its start-up, Ube Ammonia has been successfully producing the rated capacity of 1,000 metric tons of ammonia from 1,500 metric tons of coal/petroleum coke a day. The total amount of coal and petroleum coke consumed from the beginning to March 31, 1990 is about 2.0 and 0.5 million metric tons respectively. While operating the main ammonia production plant, we have discharged the slag which has been utilized as raw material of cement.

As other waste slag utilization from coal gasifier, the porous light weight aggregate "U-Light" has been commercially manufactured, since October, 1987. Currently, the supply of U-Light quantity becomes very tight in Japan due to the increase of client's demand. Thus, we believe there is a further potential market in the field of the porous light weight aggregate based on our technology.

In the following chapters, we brief on the overall operating experience of Ube Ammonia in terms of feedstock and focus on U-Light technology as commercial slag utilization.

OPERATING EXPERIENCE

In Ube Ammonia, in July, 1984, we accomplished the construction of Ube Ammonia coal gasification plant by Engineering Div. of Ube Industries, Ltd. Our ammonia plant consists of air separation, CO shift, acid gas removal, and ammonia synthesis as well as Texaco coal Gasification plant.

In early August, 1984, we started manufacturing ammonia from coal. We are very satisfied with our continuous commercial operation for almost six years. So far we have mainly gasified four kinds of coal such as Australian, South African, Chinese, and Canadian whose ash contents are ranging from 7 to 15 wt%. We also have employed petroleum coke with less ash content as feedstock since April, 1986, in order to make its diversification.

The amounts of coal and petroleum coke processed in the plant are approximately 2.0 and 0.5 million metric tons respectively since its start-up by March, 1990 as listed in Table 1.

Although this indicates that the consumption of petroleum coke over coal is gradually increased year by year, we think that this will not affect the slag availability as feedstock for U-Light production against major ammonia production.

As for the U-Light manufacturing plant, we have satisfactorily experienced for two years and half commercial operation with a capacity of 1,000 m³/month in Ube Cement factory.

As the demand of U-Light has been increased, we expect that the U-Light plant capacity should be enhanced to meet the client's request in the future.

NEW APPLICATION OF SOLID DISPOSAL

One of merits for high temperature coal gasification like Texaco Coal Gasification Process (TCGP) is an easiness of slag disposal due to no leaching substances. When the coal water slurry is gasified with oxygen, the ash in the coal is melted down to be slag in gasifier under high temperature and high pressure, and the slag becomes glassy at around 1300°C to 1400°C, while the clean syngas can be generated to utilize for many down-stream application such as C1-chemistry as well as so-called IGCC.

In case of TCGP, there are two kinds of slag such as fine and coarse discharged out of Texaco gasifier. The fine slag is carried out by track to our Isa Cement Factory as a part of raw material for cement. The remainder is coarse slag to be transported also by track to our Ube Cement Factory for manufacturing porous light weight aggregate as well as cement. At the beginning of Ube Ammonia gasification plant operation the whole discharged slag was only utilized for our cement factory. Although the quantity of slag is very small compared with the total necessity of cement raw material, the slag should be appreciated as some substitute of clay and fuel saving. In this respect, later, the cement division of UBE Industries, Ltd. has managed to research and develop more valuable way of slag utilization. In October, 1987, we commercially started the manufacturing of porous light weight aggregate made from our slag and are marketing it in Japan as very useful material whose registered name is "U-Light".

Recently, Ube Ammonia has also made an effort to have a market research for other application of coal gasification slag. That is an artificial marble, terrazzo. As we succeeded in making beautiful black terrazzo with excellent hue, we will put it to practical use if there is a potential market.

LIGHT WEIGHT AGGREGATE

The slag from gasifiers has, as shown in Table 2, comparatively low content of SiO_2 , and high content of Fe_2O_3 and CaO and some amount of unburnt carbon which work as flux and blowing agents. There are no harmful substances in terms of environmental concerns and cement chemical reaction due to the high temperature heat treatment in the gasifier.

Figure 1 shows the composition diagram for bloating materials as well as coal gasifier slag, in which the dotted line represents the limitation of bloating.

The typical composition of the coal gasifier slag does not seem to meet the necessary conditions for slag foaming proposed by Dr. C. H. Riley because of such high flux content as CaO and Fe_2O_3 . However, a good sphere shape balloon can be actually obtained by our developed method and be supplied as final product at range of diameter between 0.3 mm and 10 mm with four grades.

During the research and development work, we employed electric furnace and microscope to observe the slag shape change, and to measure bulk density and water absorption etc. under the atmosphere of air.

At the stage of preliminary research work, we only had focused on how to make more solid material rather than porous one. But, finally, the opposite phenomenon to bleed the coal gasification slag was found by chance.

The ballooning behavior is different from each coal kind, thus we have a test schedule with three phases to assure the manufacturing of good U-Light.

In commercial stage, this slag balloon, U-Light, can be produced in counter or parallel flow type rotary kiln or flash furnace in the same way as other inorganic balloon production in public.

Figure 2 shows the production process block flow for U-Light using a counter flow type rotary kiln.

The optimum blending ratio between cement and U-Light for mortar should be decided by client in terms of compressive strength as described in Figure 3.

Table 3 indicates the superiority of U-Light whose water absorption is one third of conventional light weight aggregate made from perlite and collapsing strength is three times bigger than that. The one of test results on cement mortar mixed with U-Light as its application is tabulated in Table 4. Just for your reference, the mortar flow under the table means the spread diameter of sample mortar on the turning table after 15 times rotation, which is a very familiar value to check its fluidity by Japanese plasterer.

The remarkable features of U-Light are summerized as follows :

- Sphericity in shape and smooth glass-like surface
- Extremely low water absorption
- High strength but extra-low bulk density
- High refractoriness and insulation

Based on the above characteristic, the major application using U-Light could be as follows :

- Most suitable building materials for flooring, walling and roofing especially because of extra-low bulk density and high refractoriness and insulation

- Good pumping characteristic and resistant to freeze and fusion because of extra-low water absorption
- Suitable for farming and gardening because of odorless and germfree balloon

Among those usage, U-Light has been commercially sold for pre-mixed mortar for building wall in Japan.

There are already many inorganic light-weight aggregates on a commercial basis such as glass balloon from an artificial raw material, as well as perlite and expansive shale and obsidian from a natural resource.

We think our U-Light has several advantages against those existing aggregate in terms of economics, low water absorption, and high strength. Especially, the low water absorption enables users to make stronger mortar and precast concrete without any crack by using U-Light.

Incidentally, UBE has applied for a patent on this "U-LIGHT" in Japan, United States of America, United Kingdom, South Africa, Sweden and China. In this respect, UBE is willing to license the U-Light process to each personal who is interested in as treatment method for the waste solid from coal gasification plants.

CONCLUSION

In this paper we discussed the commercial application of coal gasification slag based on our two-years-and-half experience mainly for porous light weight aggregate. There are the other applications as cement raw material experienced and Terrazzo under market research.

Except for those utilizations, we will manage to find out other applicable method intensively by integrating our each division's expertise.

We predict that the quantity of coal gasification slag will increase remarkably in conjunction with the further installation of coal gasification plant throughout the world in the future.

In this respect, there will be alternative measures to change the bothersome quantity of waste slag into more valuable material than conventional reclamation. It may not be exaggerated to say that U-Light technology will turn a misfortune into a blessing.

Table 1 Annual Consumption of Feedstock

YEAR	COAL	PC	TOTAL
1984 (from July)	137	0	137
1985	476	0	476
1986	426	46	472
1987	314	123	437
1988	303	162	465
1989	273	181	454
1990 (by March)	101	32	133
TOTAL (x 10 ³ MT)	2,030	544	2,574

Table 2 Chemical Composition of Coal Gasifier Slag

Chemical Composition (%)									Unburnt
Ig.loss	SiO ₂	Al ₂ O ₃	Fe ₂ O ₃	CaO	MgO	SO ₃	Na ₂ O	K ₂ O	C (%)
3.1	38.8	22.1	9.4	19.2	1.6	0.2	1.6	0.6	2.9

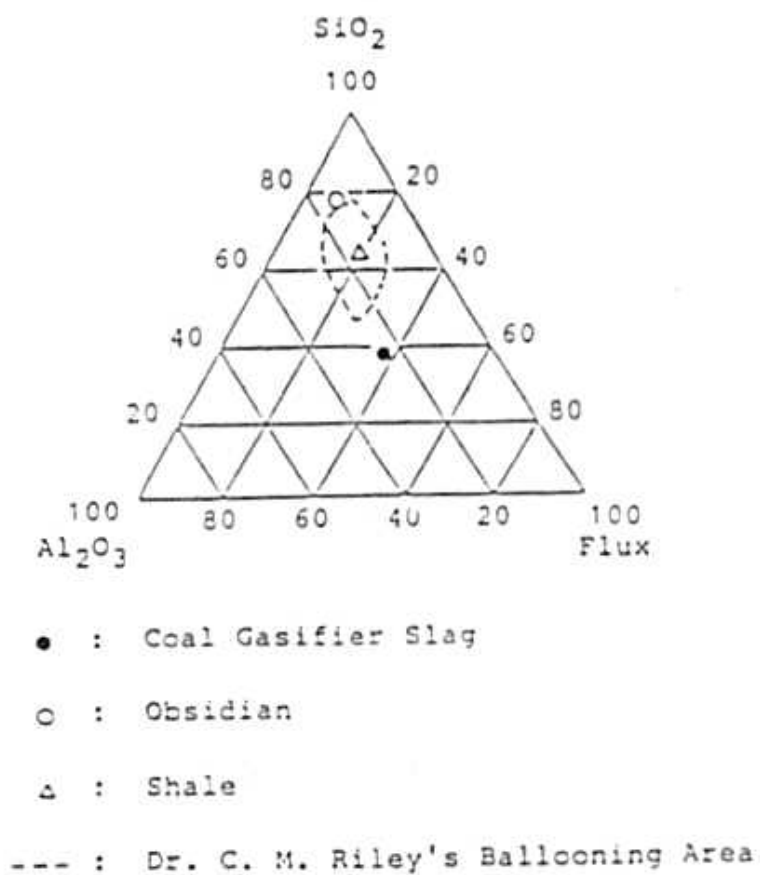


Figure 1 Triangular diagram

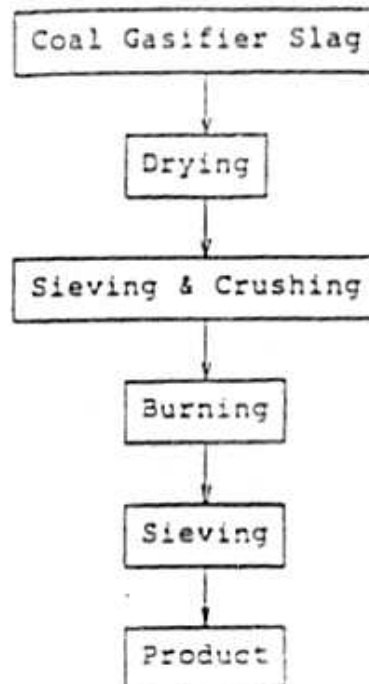


Figure 2 Process Flow Sheet

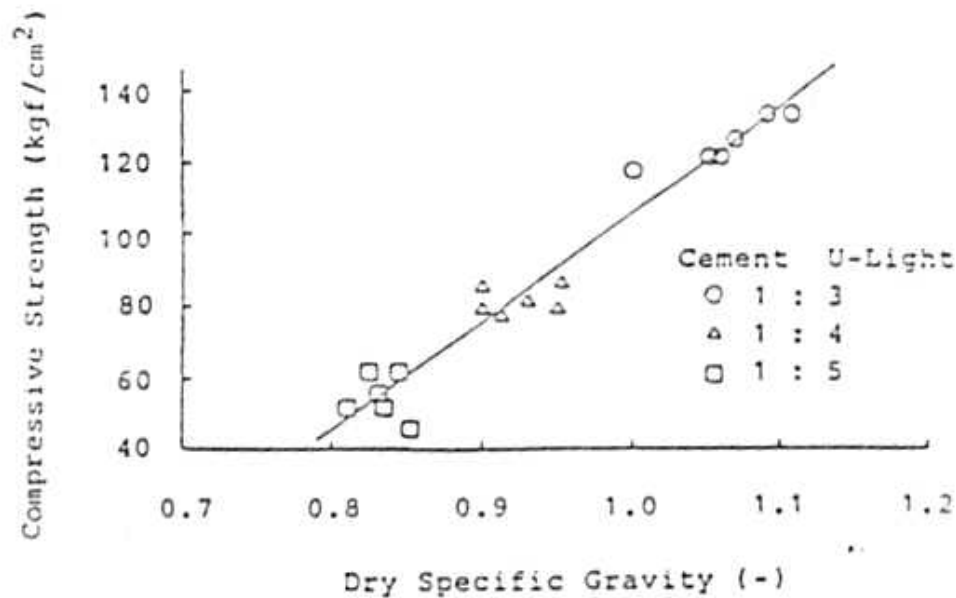


Figure 3 Relation between 28-days-compressive Strength and Dry Specific Gravity*

Table 3 Quality of U-Light*

	Raw Material	Particle Diameter (mm)	Bulk Density (kg/l)	Water Absorption(%)	Collapsing Strength (kgf)
U-Light	Coal Gasifier Slag	0.15-10	0.15-0.45	5.0	2.1
Conventional Product	Perlite	0.15-15	0.10-0.40	16.9	0.7

Table 4 Test Results on Cement Mortar Mixed With U-Light*

Volumetric Mixing Ratio Cement : U-Light	Bending Strength (kgf/cm ²)	Compress Strength (kgf/cm ²)	Dry Specific Gravity (-)	Water Absorption (%)	Thermal Conductivity (kcal/mh°C)
1 : 3	27	120	1.051	27.8	0.205

Mortar Flow = 180 ± 10 (mm)

(*) NOTE : Those figures are based on the experimental method by JIS.

Texaco Gasification: Powering the 90's

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Introduction

In the latter stages of the 1990's, Texaco Gasification Power Systems (TGPS) have come of age. Ten years ago, Texaco, as a member of the Cool Water Coal Gasification Program, successfully demonstrated that the Texaco Gasification Process could be mated to a combined cycle power plant.

This technology has matured in the intervening years and in the 1990's, nearly 2000 megawatts of power capacity may be installed that will be fueled by syngas produced by Texaco's gasification process.

The first part of this paper will give an overview of these new power projects, each now in some stage of engineering and construction. The second part of the paper will focus on the El Dorado Gasification Project, a project that embodies exciting new directions for the TGPS.

Background

The Texaco Gasification Process was developed in the late 1940s. It was intended to produce hydrogen and carbon monoxide - syngas - for chemical plant and refinery applications. It was originally designed to be fed natural gas. In the 1950s, it was modified for heavy oil feeds, and in the 1970s for solid feeds like coal and petroleum coke.

Texaco gasifiers soon will produce 2.9 billion standard cubic feet of syngas per day in thirty-seven currently operating installations around the world and twelve new installations now in detailed engineering and construction. Much of this capacity still is used for chemicals production. But with the committed projects discussed in this paper, at least 25% of the syngas generated by Texaco gasifiers will be used for power production by the end of the decade.

Among commercially proven technologies, Texaco Gasification Power Systems based plants remain the most environmentally benign means of generating electricity from sulfur-containing feedstocks. TGPS plants emit a fraction of the NO_x and SO_x air pollutants that are produced from conventional or fluidized bed boiler installations. And even the most advanced boiler systems produce solid wastes in quantities far in excess of those produced in TGPS plants.

Texaco Gasification to Power in the '90s

In the latter half of the 1990s, Texaco gasification to power plants will become a significant new source of electric generating capacity. Six new gasification to power facilities are committed that will generate a nominal net total of 1765 MW. Other projects are in various stages of development that may push this total to 2000 MW.

Texaco has issued licenses for the following projects. All megawatts given are net outputs:

1996 Startup: Polk Power Station, Tampa Electric Co., 260 MW
El Dorado Refinery, Texaco Refining and Marketing Inc., 35 MW

1997 Startup: Falconara Refinery, API Energia S.p.A., 220 MW

1998 Startup: Sarlux Project, SARAS S.p.A., 500 MW
Sicily Refinery, ISAB S.p.A., 500 MW

1999 Startup: Sannazzaro Refinery, AgipPetroli S.p.A., 250 MW

The Polk Power Station will be fed by coal. The El Dorado Project will be fed by petroleum coke and refinery waste streams. The four Italian projects will be fed by heavy oil or asphalt.

The Polk Power Station will be the first coal gasification based power plant since the Cool Water Plant completed its demonstration in 1989. The Polk unit is designed to be the most efficient, and cleanest, coal fired power plant in the country.

The last four projects listed above are at Italian refinery sites. Two forces in Italy have driven their accelerated interest in Texaco gasification to power:

- *Italy is in need of new power generation*

Fifteen percent of its power is now imported, nuclear power is banned, and 50% of its domestic power production is from combustion of high sulfur fuel oil. To address this power shortage, the Italian government has offered incentives for independent power production.

- *Heavy fuel oil is dropping in value in Europe*

European Economic Community directives call for reduced SOx emissions, which will reduce the general demand for high sulfur fuel oil. The Italian national electric utility, ENEL, will cease purchase of high sulfur fuel oil in 1997. Most of this utility fuel oil is generated by Italian refiners.

Gasification to power is an attractive way for Italian refiners to benefit, rather than to be penalized, from both of these forces. By feeding their heavy oil fractions to an integrated gasification combined cycle (IGCC) plant, a potential waste problem is converted into a major new revenue source - clean power for themselves and for export.

These refiners also will take advantage of numerous refinery synergies with gasification. They will be free to refine lower cost, heavy high sulfur crudes without suffering penalties for producing more high sulfur heavy ends. They may reduce SOx and NOx emissions by gasifying, rather than burning, their fuel oil. Many of these refiners will co-produce hydrogen from the syngas at low cost for their refineries.

Many of these same driving forces for refinery IGCC construction are also developing in other European countries. In the U.S., petroleum coke production is a more common product of the heavy ends of refinery processes. Coke is dropping in value in the U.S. for many of the same reasons that heavy oil is in Europe.

Texaco is continuing to actively develop gasification to power projects world-wide.

The El Dorado Gasification Project

The El Dorado Gasification Project is of significant strategic importance for several reasons:

- It will demonstrate that small, low capital cost gasification to power plants are economical.
- It will demonstrate that waste streams may be converted by gasification to valuable products in an environmentally superior way.
- It will demonstrate that, in the right applications, gasification to power is more economical than natural gas to power.
- It will demonstrate that adding gasification power plants to a refinery improves the efficiency and flexibility of the existing operations.

Small: The El Dorado Gasification Project will be fed by 166 short tons per day (tpd) of petroleum coke and 6-16 tpd of refinery waste streams. The gasification plant is sized to gasify only the lowest value streams produced by the refinery. Startup is scheduled for mid-1996.

Syngas is fed to a combustion turbine-generator along with natural gas. By heating value, the turbine is loaded with one-third syngas and two-thirds natural gas. By volume, the reverse is nearly correct.

Products of this refinery unit are 35 MW net power, 180,000 pounds per hour of steam, and pressurized air, nitrogen and oxygen. This amounts to the total power needs of the refinery with no normal export power, about 40% of its steam requirements, all of its nitrogen requirements, and supplementary oxygen and instrument air for its refinery operations.

The capital cost of the unit will be \$66 million, in as spent dollars, excluding owner's costs. This installed cost includes all of the new equipment required for the unit, including its integrated air separation unit, liquid and solid feed preparation, syngas production facilities, and the power block. Home office engineering, field indirects, and contingencies are also included.

The unit will use existing waste water treating, sulfur recovery, and flare systems in the refinery.

With owner's costs, including owner project management, insurance, project development costs, startup costs, spare parts, permitting costs, and other costs, the project will cost about \$75 million in as-spent dollars.

Waste: This unit will be fed by the portion of the petroleum coke generated by the refinery that has become unprofitable to market. Pending Kansas Department of Health and the Environment (KDHE) approval, it will also be fed by various refinery waste streams of zero or negative value to the refinery.

The gasifier will convert these low-value streams to clean syngas. The unit will also produce pure sulfur and fuel-grade solids as by-products. The plant is not expected to produce any significant quantities of solid waste, and will have exceedingly low air emissions.

The project has gained enthusiastic support in the area, as it has the potential to substantially reduce, or even eliminate, organic waste disposal from the plant. Lower truck traffic, lower waste handling risks, and reduced incinerator emissions in the area will result.

Economics: The El Dorado refinery had investigated natural gas fired cogeneration at their plant and rejected it due to poor economics. The avoided cost of power to the refinery in the area did not justify this sort of project.

The gasification to power project has economics that are superior to those of a simple natural gas fed cogeneration project. There are three essential reasons for this:

- All of the gasifier feeds are of low or negative value to the refinery.
- The project has several synergies with the existing refinery operation.
- No new natural gas will be purchased for this project.

The gasification process's ability to produce a valuable product - syngas - from the lowest valued streams is a key to the success of this project. Most power projects' cost of power contains a variable fuel charge that is a major portion of its cost. In this case, the fuel charge is zero or negative.

Many of this project's synergies with the refinery will be discussed below. By helping the existing operations produce refined petroleum products less expensively, the project takes on the higher rates of return usually associated with refining projects rather than the lower returns usually associated with utility projects.

The natural gas that is routed to the turbine in this project is gas that normally feeds the refinery's gas-fired boilers. A compensating amount of steam is produced by the new, efficient heat recovery steam generator. Because the refinery will require no new gas purchases for this project, the price and variability of natural gas do not impact this project's economics.

Refinery synergies: Texaco gasification was developed as a refining and chemical plant process. Thus it should come as no surprise that it can bring value to the existing operations of such plants beyond the simple production of power and steam. This gasification to power project gives the refinery:

- *Long term control of its major operating expenses*

Like any cogeneration project, the refinery's power costs will now be well defined and within their control. Unlike other cogeneration projects, their nitrogen, supplementary oxygen, and waste disposal costs will also be defined and controlled.

- *Increased flexibility in crude running capability*

The gasification unit's presence will allow the refinery to process a wider variety of crudes. The plant will have greater ability to run lower cost crudes - with higher sulfur contents and more heavy ends - due to sulfur plant debottlenecking with oxygen and due to having a long term home for its lowest quality coke.

- *Reduced exposure to waste disposal liabilities*

To the extent that the plant is allowed to gasify its own waste products, it will not incur the risks associated with their disposal by third parties.

- *Improved plant reliability*

Because their current sources will not be cut-off, the plant will achieve greater steam, power, nitrogen, and plant air reliability. This will nearly eliminate refinery unit shutdowns and off-spec products upon re-starts due to power surges or outages. Steam interruptions due to boiler problems will also be nearly eliminated.

- *Potential for chemicals co-production*

The refinery does not have a current need to use syngas for its value as a petrochemical feedstock. Should market or regulatory conditions change in the future, however, the gasification operation could be easily expanded to co-produce hydrogen, methanol, or other important petrochemical feedstocks.

Current Directions

Texaco is aggressively moving to expand the use of the TGPS. To do this, full advantage must be taken of the unique capabilities of the process. Project development efforts must capitalize on the ability of the TGPS to:

- Beneficially use low value feedstocks
- Produce high value products
- Perform with superior environmental results
- When applicable, add value to existing operations

The TGPS is fully capable of converting very low quality feeds to valuable products. This is a powerful economic driving force for gasification. New environmental restrictions will continue to reduce the value of heavy, high sulfur hydrocarbons and eliminate many current means of waste disposal.

In the past, this has meant projects fed by high sulfur coal, heavy oil, and petroleum coke. We now add refinery and chemical plant waste streams, waste oil, contaminated soil, waste plastics, used tires, waste water treating sludges, and other wastes to this list of potential feeds where applicable.

The products of the TGPS are, by contrast, of high value. Products such as power, steam, hydrogen, and carbon monoxide have been the foundations of the gasification business. We now add nitrogen, oxygen, methanol, sulfur-free fuel gas, and other co-products to the list of products that can add value to the project.

The TGPS remains among the world's most environmentally preferred means of producing the many products just discussed. In the past, the process' ability to far exceed emissions standards made for good public relations, but had little economic value.

Now, the ability to assign value to NOx and SOx credits can add a significant revenue stream to projects. In other cases, allowing shutdown or re-fueling of existing boilers saves the high operating and maintenance costs associated with stack scrubbers.

Seeking out opportunities to allow gasification to synergize with existing operations can pay big economic dividends. In many instances, small adjustments to the new TGPS facility allows significant benefits to existing processes that are bottlenecked, that rely on outside gas purchases, or that are fed by expensive or high polluting processes that make syngas or its components.

Gasification to power projects became a difficult economic sell in the years following the end of Cool Water Project demonstration. This has resulted in a leaner, smarter, more focused Texaco Gasification Power System that is now poised to power the '90s - and beyond.



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News from **TEXACO**

TEXACO GASIFICATION TECHNOLOGY SELECTED BY EXXON, KOCH

**Texaco Technology Increasingly Attractive to Refiners
for Power Generation**

FOR RELEASE: WEDNESDAY, NOVEMBER 1, 1995.

WHITE PLAINS, N.Y., Nov. 1 - Texaco announced today that Exxon Chemical and Koch Refining Company have each licensed Texaco Gasification Power Systems technology to generate electricity from petroleum coke and other low-value refinery byproducts. These projects can also produce steam and hydrogen.

The worldwide agreement between Texaco's Alternate Energy group and Exxon Chemical provides the basis for Exxon Chemical and other Exxon affiliates to build gasification plants at multiple locations throughout its refining and chemical business. In addition to licensing this proprietary technology to Exxon, Texaco also will provide engineering and technical services. Exxon will designate specific project sites at future dates.

Agreement was reached also between Texaco and Koch Refining Company to utilize the Texaco Gasification Power Systems technology in a project which would gasify petroleum coke to produce electric power, hydrogen and steam. The project is being developed by Koch at its Rosemount, Minnesota refinery.

David C. Crikelair, Vice President of Texaco Inc. and head of Texaco's Alternate Energy group, said, "We are extremely pleased that Exxon Chemical and Koch have selected our gasification technology. The Exxon and Koch projects, along with other projects throughout the world, demonstrate that Texaco's gasification technology is increasingly attractive to refiners and chemical producers who recognize its superior environmental performance, efficiency and operating flexibility."

Four Italian refinery projects also are using the Texaco Gasification Power Systems technology for projects that are under development to produce more than 1,500 megawatts of electricity, plus hydrogen and steam. The superior environmental performance of the technology enables the Italian refiners to use high sulfur fuels, including heavy oil residue, in compliance with stringent European Union environmental standards.

In addition to the Exxon and Koch projects, Texaco is constructing a Texaco Gasification Power Systems facility at its El Dorado, Kansas, refinery. Once operational in 1996, this \$75 million plant will gasify petroleum coke and hazardous wastes to produce 40 megawatts of power and 180,000 pounds per hour of steam. The El Dorado project has established an important precedent by receiving a ruling from the U.S. Environmental Protection Agency that exempts the gasification facility at the refinery from normal hazardous waste permitting requirements because of the technology's proven unique environmental performance.

Emissions from a Texaco Gasification Power Systems facility are far lower than those from conventional power technology utilizing the same feedstocks, and because of its feedstock flexibility and diverse product slate, the Texaco Gasification Process can serve multiple purposes in a refinery thereby enhancing the refinery's ability to vary its crude selection.

Texaco is recognized as the world leader in gasification technology, an environmentally advanced technology that converts hydrocarbon fuels into clean-burning synthesis gas (syngas) to produce electricity, chemical fertilizer, town gas, chemicals and other industrial products. Worldwide, Texaco owned or licensed gasification facilities operating, or under development, have a total syngas production capacity in excess of three billion standard cubic feet per day.

- xxx -

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TEXACO INC.

Listing of Coal Gasification Reports Available
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<u>EPRI Reports</u>	<u>Title</u>	<u>Date</u>
GS-6806	Cool Water Coal Gasification Program: Final Report.	August 1990
GS-6819	Texaco Coal Gasification Wastewater Handling and Treatment Pilot Plant. - Volume 1: Performance Summary - Volume 2: Wastewater Sampling & Analysis	August 1990
GS-6165	Technology Assessments for Advanced Fossil Power systems. Bevilacqua-Knight Inc.	December 1989
GS-6470	Technical Assessment of the Indirect-Fired Gas Turbine Power Plant.	September 1989
GS-6485	Eighth Annual EPRI conference on Coal Gasification.	August 1989
GS-6439	Long-Term Leaching Tests with Coal Gasification Slag. Radian Corporation and Tennessee Valley Authority.	July 1989
GS-6415	A Comparison of Steam-Injected Gas Turbine and Combined-Cycle Power Plants Technology Assessment. Jersey Central Power and Lights Company, and Sargent & Lundy.	June 1989
GS-6173	Development of an IGCC Power Plant Simulator. Stone and Webster Eng. Corp.	February 1989
AP-6007-SR	Proceedings: Seventh Annual EPRI Contractor's Conference on Coal Gasification.	October 1988
AP-5931	Cool Water Coal Gasification Program: Fifth Progress Report. Cool Water Coal Gasification Program.	October 1988
AP-5966	Downtime Corrosion in Syngas Coolers of Entrained Slagging Gasifiers, Lockheed Missiles and Space Co.	September 1988
AP-5893	Treatability Testing of KILnGAS and Texaco Coal Gasification Waste Waters, CH ₂ M Hill and Energy and Minerals Research Center, North Dakota.	July 1988

AP-5628	Erosion - Corrosion of Materials In Coal-Water Slurries. Lawrence Berkeley Laboratory.	February 1988
AP-5505	Process Screening Study of Alternative Gas Treating and Sulfur Removal Systems for IGCC Power Plant Applications. SFA Pacific.	December 1987
AP-5342-SR	Proceedings. Sixth Annual EPRI Contractor's Conference on Coal Gasification.	October 1987
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AP-4905	Low Rank Coal-Water Slurries for Gasification: Phase 2 analytic Studies. University of North Dakota. Energy Research Center.	December 1986

AP-4827	Co Production of Carbon Dioxide and Electricity. Fluor Technology Inc.	November 1986
AP-4849	Investigation of Low-Rank-Coal--Liquid Carbon Dioxide Slurries. Arthur D. Little, Inc.	October 1986
AP-4832	Cool Water Coal Gasification Program: Fourth Annual Progress Report. Cool Water Coal Gasification Program, Bechtel Power Corporation and Radian Corporation.	October 1986
AP-4680	Proceedings: Fifth Annual EPRI Contractor's Conference on Coal Gasification.	July 1986
AP-4657	Coproduction of Peaking Fuel In IGCC Power Plants: A Process Screening Study. Air Products & Chemicals, Inc.	July 1986
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AP-4509	Use of Lignite in Texaco Gasification-Based-Combined-Cycle Power Plants, Energy Conversion Systems, Inc.	April 1986
AP-4435	Thermal Upgrading of Low Rank Coal: A Process Screening Study. Bechtel Group, Inc.	March 1986
AP-4452	Laboratory Study of Corrosion of High Temperature Alloys/Coatings in Simulated Medium Btu Gas Atmospheres. Argonne National Laboratory.	February 1986
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AP-4344	Corrosion in Quench Systems of Entrained Slagging Gasifiers - A Laboratory Study - ITT Research Institute.	November 1985
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AP-4177	Proceedings: Fourth Annual EPRI Contractor's Conference on Coal Gasification.	August 1985
AP-4106	Dynamic Simulation Models for Selective Sulfur Removal in Coal Gasification Systems. Hyprotech Ltd.	July 1985
AP-3876	Cool Water Coal Gasification Program - Third Annual Progress Report. Bechtel Power Corporation Interim Report.	January 1985
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AP-2487	Cool Water Coal Gasification Program - First Annual Progress Report Bechtel Power Corporation Interim Report.	July 1982

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Commercial Implementation of the Proven Texaco Gasification Process for Power Generation - By: E. O. Gerstbrein and W. R. Guenther	May 1991
Development of an Energy Conversion & Syngas Production Process - By: Edward T. Child	April 1991
Texaco Gasification Project - Status and Hytex Introduction - By: W. R. Siegart	April 1991
Hytex: A Novel Process for Hydrogen Production - By: Francis Fong & Manuel Quintana	March 1991
Texaco Coal Gasification - Freetown Energy Park - By: W. Raymond Siegart	March 1991
Electric Power Generation and the Environment - By: Edward T. Child	Feb. 1991
Gasification of Sewage Sludges - By: Richard B. Zang and Rashid Khan	Jan. 1991
Ammonia From Low-Grade Oil Residues Using Texaco Gasification Technology - By: M. E. Quintana	Dec. 1990
The Use of Orimulsion as a Feedstock for the Texaco Gasification Process - By: W. F. Fong & M. E. Quintana	Dec. 1990

Commercial-Scale Power Generation Using Texaco Coal Gasification - By: P. A. Smith & P. F. Curran	Dec. 1990
Clean, Green and Competitive Coal Gasification Comes of Age - By: C. B. Malin	Nov. 1990
Clean, Cost Competitive Electrical Power From Coal Via The Texaco Coal Gasification Process - By V. R. Shorter & P. A. Smith	Oct. 1990
The Utilization of Petroleum Residues for Generation of Industrial Gas and Chemical Products - By: M. E. Quintana	Oct. 1990
Texaco Coal Gasification Process: A Clean Coal Technology in Repowering - By: W. R. Siegart	Sept. 1990
Texaco Gasification of Petroleum Residues By: M. E. Quintana	May 1990
Texaco Coal Gasification Development and Commercialization - By W. Raymond Siegart	May 1990
Commercial Application of Slag From Texaco Coal Gasification Plant in Ube Ammonia - By: K. Katagiri	May 1990
Pilot Plant Evaluation of Orimulsion as a Feedstock for the Texaco Gasification Process - By M. E. Quintana & L. A. Davis	April 1990
Coal Gasification - Today's Clean Route to Electric Power - By G. N. Richter	April 1990
The Texaco Coal Gasification Process: A Means to Produce Clean, Cost Competitive Power From Coal - By W. E. Preston	April 1990
Texaco Coal Gasification - New Projects and Forward Movement - By W. Raymond Siegart	April 1990
Coal Gasification - Today's Clean Route to Electric Power - By G. Neal Richter	March 1990
Waste Destruction by the Texaco Gasification Process - By Jamie Miranda	March 1990
Canadian Perspectives for IGCC - Texaco Coal Gasification Status and Developments - By P. F. Curran	March 1990

A Reconciliation of the Cool Water IGCC Plant Performance and Cost Data with Equivalent Projections for a Mature 360 MW Commercial IGCC Facility - By M. J. Gluckman, D. F. Spencer, D. H. Watts, & V. R. Shorter	October 1987
Port Arthur Research Laboratories - Computer Control: Applications to Grease Manufacture By: J. M. Massey, D. A. Turner, A. C. Witte	July 1987
Summary Concerning the Activities and Experiences of the Southern California Edison Company in the Area of Available and Emerging Technologies for the Control of Acid Rain Precursors - By: L. T. Papay	March 1987
The Texaco Coal Gasification Process and its Worldwide Commercial Applications - By: M. E. Quintana & R. Gupta	Sept. 1986
Preliminary Environmental Monitoring Results for the Cool Water Coal Gasification Program - By R. W. Grover	August 1986
Cool Water: Performance & Economics - By: W. N. Clark, R. L. Litzinger, & I. R. Straughan	August 1986
Relative Economic Values of Different Coals for the Texaco Coal Gasification Process - By: J. Hibbel, V. Schmidt, J. Langhoff, R. Durrfeld, C. P. Marion	October 1985
Combined Cracking Processes Boost Fuel Fields From Low-Quality Crudes and Residua - By: T. E. Johnson, J. R. Murphy, K. G. Tasker	July 1985
Technical and Economic Comparison of Methanol Production from Coal, Oil, and Natural Gas - By: D. J. Goerz & B. R. Gilbert	May 1985
Integrated Gasification/Combined Cycle (IGCC) Electrical Power Production - A Rapidly Emerging Energy Alternative - By: C. B. McCarthy & W. N. Clark	April 1985
The TVA Ammonia From Coal Project - 1985 Update By: D. A. Waitzman, R. G. Lee, D. E. Nichols, P. C. Williamson	April 1985
Economics of the North Alabama Coal To Methanol Project - By: J. F. Weinhold	April 1985

1985 Electric Utility Energy Conservation and
Environmental Protection Awards (Reprint from
Power Magazine)

April 1985

Ammonia By Coal Gasification - By: T. Sueyama,
T. Tsujino, and K. Okada

March 1985

Texaco Coal Gasification Process for Production
of Clean Synthesis Gas from Coke - By:
W. G. Schlinger, J. H. Kolaian, M. E. Quintana,
T. G. Dorawala

March 1985

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AT TELEPHONE NO. (914) 253-6019

**TAMPA ELECTRIC COMPANY
DOCKET NO. 960409-EI
FPSC STAFF'S 1st SET
INTERROGATORY NO. 19
WITNESS: BLACK
PAGE 1 of 19**

19. Please identify all documents considered by TECO in reaching the conclusion pet coke is a viable fuel for the IGCC facility as detailed in its response to Staff's Interrogatory No. 3, in Docket No. 950379-EI.

A. In the 1992/1993 time frame, Tampa Electric considered information based on discussions with Texaco experts and with personnel from the Ube Ammonia Facility in Japan which utilized pet coke in accessing the feasibility of using pet coke as a fuel. There are no documents that memorialize this information. Subsequently, we considered the following documents in our ongoing evaluation of the feasibility of burning pet coke:

- 18-2. GE Process Specification -
Fuel gases for combustion in heavy-duty gas turbines provided in response to Interrogatory No. 18 of FPSC Staff's First Set - Docket No. 960409-EI. Specific reference to pet coke is given on page 4, paragraph IV "Gasification Fuels."
- 18-5. Texaco Fuel Flexibility References - as provided in response to Interrogatory No. 18 of FPSC Staff's First set - Docket No. 960409-EI
- 19-1. Memorandum dated May 31, 1995 from D.A. Cowdrick to C. R. Black, Subject: Polk Performance Project - pet coke/Coal Blends
- 19-2. Interoffice Memorandum dated September 21, 1994 from D. A. Cowdrick to Don Pless, Subject: Polk Performance Projection - Power River Basin/pet coke Blend
- 19-3. Intra project Memorandum dated September 19, 1994 from J. E. McDaniel to Mike Carlson, Subject: Performance Projection - Power River Basin/pet coke.
- 19-4. Memorandum dated May 16, 1994 from D. A. Cowdrick to D. E. Pless, Subject: Updated Polk Performance Estimates.

-03 1 3

MEMORANDUM

May 31, 1995

TO : C. R. Black

FROM : D. A. Cowdrick

SUBJECT : Polk Performance Projection - Pet Coke/Coal Blends

References - Memo, DACowdrick to DEPless, September 21, 1995, "Polk Performance Projection: Powder River Basin/Pet Coke Blend" and Memo DACowdrick to DEPless, May 16, 1994, "Updated Polk Performance Estimates"

In my memo to Don on 9/21/94, I referred to potential capital requirements for flux addition if we were to burn the pet coke/PRB coal blend. In the 5/16/94 memo, it also mentions that fluxing would be required for pet coke blends with Lower Kittanning or Raton Basin coals. At your request we have taken another look at the potential capital costs we may require to operate on these pet coke/coal blends. For capital costs, three basic issues are apparent and another set of possible issues is identified. In addition to capital costs, some O&M impacts have also been identified. In summary, to burn either of the three pet coke/coal blends evaluated to date, we would expect to have to spend between \$100,000 and \$4,000,000. In addition, additional O&M expenses may be incurred to provide for off site disposal of some of the solid by products and for maintenance in the syn gas containing systems and equipment.

Capital Costs**FUEL HANDLING**

Fuel handling is the one area most affected by burning blends of pet coke and coal. The assumptions to date are that blending of the coke and coal will be done prior to receipt at the Polk Site, either at Big Bend Station or at the Electro Coal Transfer facility or on the ocean going ships themselves during loading at Electro Coal. If this is the case, the only impact is the additional cost that may be incurred from the blending process at those sites. The one concern we have is that the blend may have a tendency to separate during handling, either in the trucks, during loading or unloading, or during handling at Polk (such as separation while flowing out of the silo.) We will be researching this issue further over the next few weeks to see if we can determine if this is a real issue or not. If it is and we have to add blending provisions at the site, we estimate adding one new silo about

the size of one of the two existing ones, and some additional material handling equipment at a total installed cost of about \$3 million. So the cost for fuel handling would be from \$0 - \$3 million.

CHLORIDES

Under steady state operation at the splits we identified, and the chloride levels reported, the brine concentration system should be OK. There may be a problem, however, during initial operations when we are operating at high coal to coke ratios. The L. Kittanning and Raton Basin coals both have chloride levels higher than the design coal. We may be limited in the number of hours of operation (in days, not weeks) due to higher than designed chloride levels in the initial blends. This would complicate the operation on these fuels, but it is not clear what, if anything, we could do to get around this problem without increasing brine concentration system capacity, which is a very costly option. For now we are assuming we would find some way around this issue without spending significant capital dollars. The PRB coal has a very low chlorine level as does the pet coke. This would require us to operate the brine concentration system at reduced load and/or at lower inlet concentration levels. So far we do not see that as a problem.

FLUXING

Fluxing of the coke/coal blends is expected to be required to a) lower the ash fusion temperature to assure we get the ash to flow and/or b) to add ash volume to assure we have enough ash flowing to remove the metals inherent in the fuels and assure proper operation of the gasifier and RSC. Flux material could be limestone, shell, coal slag, or possibly gypsum. Sand or dirt may not be practical due to the silica it would add to the system. It is expected that adjusting of the flux amount during operations would be required on a short turn around basis as opposed to coal/coke blend adjustments which probably can be made over a period of days. This would require the flux to be added to the system some point after the fuel leaves the silo and by the time it gets to the rod mill. A system to accommodate this could be installed for somewhere between \$100,000 and \$500,000, depending on the requirements and where the flux needs to be added.

CARBON CONVERSION OR OTHER GASIFIER PERFORMANCE ISSUES

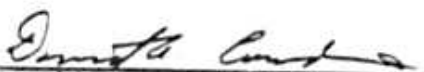
There is some potential that the coke/coal blends will not perform as expected. It is not known what form this may take, but some examples would be carbon conversion and COS production. If the carbon conversion is very low, we may have to add additional gravity settler capacity. If more COS is formed than expected, additional AGR an, potentially, sulfuric acid capacity may need to be added. We are currently assuming

that the most likely scenario would be low carbon conversion and therefore estimate additional gravity settler capacity cost at from \$0 - \$500,000.

Operating & Maintenance Costs

Burning of these pet coke/coal blends may increase O&M costs due to several factors. First, assuming fluxing is necessary, additional costs will be incurred to buy the flux and to operate and maintain the flux addition equipment. Second, if blending is required at the site, additional costs will be incurred to operate and maintain the blending equipment. Two other O&M impacts are related to the presence of vanadium, and potentially other heavy metals, in the pet coke. The pet coke is assumed to have vanadium in it from the refining processes. The presence of vanadium in the slag and fly slag may have some impact on the potential uses of these by products, which could decrease the revenues from, or increase the cost of, disposal. We will be reviewing our contract for sale of the slag to see if the presence of vanadium is an issue. In addition, if the vanadium settles out in any of the equipment, rather than coming out encapsulated in the slag and fine slag, it could complicate the procedures necessary for maintaining the equipment to minimize personnel exposure and/or prevent release to the environment.

I hope this addresses the issues to your satisfaction. If I can provide any additional information, please call. In addition, I will get back to you soon on the two issues we will be following up on.


David A. Cowdrick

cc: W.N. Cantrell
S.J. Martin
D.E. Pless
R.L. Boehm
File TPH1

To Don Pless

Subject Polk Performance Projection:
Powder River Basin/
Pet Coke Blend

File No.

Date September 21, 1994

From D. A. Cowdrick

of Project Engineering

Copies to C. R. Black J. E. McDaniel
C. A. Shelnut M. D. Grant
T. Hernandez File TPH1

At 3040/7N653 Ext. 2638

We have run our plant models to estimate Polk performance with a blend of 35% Powder River Basin Coal and 65% Pet Coke. The composition of the blend is per the fuels department analysis, attached. The model predicts the plant will produce 250.3 MW (net) at a heat rate of 8869 BTU (HHV)/KWH at a 90°F ambient temperature. Flux must be added to the slurry to facilitate operation with this blend. No facilities currently exist for the addition of flux and the capital required should be considered.

The Powder River Basin/Pet Coke blend appears to be an attractive option with most of the existing plant equipment operating well within the design range. However, this blend will have less operational flexibility than other blends we have considered (Raton Basin, Lower Kittaning) due to the high inherent moisture. This limits the slurry concentration which can be achieved and negatively impacts heat rate. We will also have to address the low chloride concentration which will require significant turndown in the brine concentration area or possibly batch operation.

While our model predicts performance based on the coal/coke blend's composition, it is important to note that there are many unknowns associated with this mode of operation. These unknowns include: fouling characteristics in the gasifier, RSC and transfer lines; slag/ash composition considering the potential presence of vanadium; impacts due to other minerals present; etc.

Given these unknowns, for pet coke blends, as well as for any coals other than our design coal, a test burn must be completed prior to any firm commitment on plant operating characteristics or on long term fuel purchases. We are somewhat more comfortable projecting performance with alternate coals since Texaco gasifiers have operated with a range of coals. However, no Texaco gasifier with syngas cooling has ever operated with a pet coke blend.

For these reasons, it is our recommendation that for any Pet Coke blend to be considered as a long term operating fuel, a detailed test program will have to be developed. This test program will have to include a "test burn" phase in period where we can gradually increase the percentage of pet coke over a period of several months. Our ability to operate with these low pet coke blends during the phase in period will have to be further evaluated.

MEMORANDUM

May 31, 1995

TO : C. R. Black
FROM : D. A. Cowdrick
SUBJECT : Polk Performance Projection - Pet Coke/Coal Blends

References - Memo, DACowdrick to DEPless, September 21, 1994, "Polk Performance Projection: Powder River Basin/Pet Coke Blend" and Memo DACowdrick to DEPless, May 16, 1994, "Updated Polk Performance Estimates"

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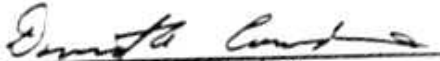
41

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David A. Cowdrick

cc: W.N. Cantrell
S.J. Martin
D.E. Pless
R.L. Boehm
File TPH1

Polk Power Station**Intraproject Memorandum**

To: Mike Carlson

Subject: Performance Projection:
Powder River Basin/Pet Coke

Date: September 19, 1994

From: J. E. McDaniel

Company: EPRI

Copies to: Dave Cowdric
Mark Grant

I have run our plant models to estimate Polk performance with a blend of 35% Powder River Basin Coal and 65% Pet Coke per Mark Senior's attached analysis. The models predict it will produce 250.3 MW (Net) at a heat rate of 8869 BTU (HHV)/KWH at 90 °F ambient temperature. I verbally communicated these estimates to Claudine Caballero late on Thursday, 9/15.

These projections were developed in exactly the same manner as the last estimates we provided Generation Planning on various coals and Pet Coke blends, so the numbers can be compared directly. I do expect minor deterioration in projected performance across the board after I update the models to reflect the current motor list, the actual designs of the H₂SO₄ Plant and Brine Concentration Unit, and a minor change in the steam cycle.

Powder River Basin/Pet Coke appears to be a very promising blend. Of course, the caveat we expressed with our earlier projections still applies: the plant was not designed for this feedstock, so a thorough test program will be required to verify operability and performance. The following paragraphs discuss some of the factors which must be considered for this feedstock and determined in such a test program.

All of the plant units seem to be comfortably within their design range except brine concentration. In contrast to other coals and blends we have evaluated, this blend has a very low chloride content (350 ppm dry basis). This will require deep turndown of brine concentration to about 1/4 of its design capacity, but this should not pose insurmountable problems. Nevertheless, we should take the opportunity now to explore with Aquachem how to best turn down that unit.

2-5

The composition of the slag will more closely resemble that of Western U.S. coals than Eastern U.S. coals for which the plant is designed. Consequently, we can expect that scaling in the grey and black water systems and the methods to combat it will be more like Cool Water's than at Tennessee Eastman's.

Fluxing must still be considered for this blend. The Lower Kittanning and Raton Basin/Pet Coke blends which were previously evaluated definitely would require flux because of their extremely high ash fusion temperature. Although the fusion temperature of the Powder River Basin/Pet Coke blend (2340 °F) appears acceptable compared to that of the other blends, the ash quantity (2.3% dry basis) will be very low and the vanadium content of the slag (2.7%) will be quite high compared to that of coals with which I have had experience. Flux may still be needed to assure flow of slag and thorough encapsulation of the toxic vanadium.

Claudine indicated that the capital facilities to add flux and the cost of the flux are not currently included in their economic evaluations or preliminary designs of the Big Bend blending facilities. My strong preference would be to add all flux at Polk rather than at Big Bend to assure that it wouldn't segregate in transit, by handling, or in Polk's silos. A successful flux addition system such as the one proven at Cool Water should be relatively inexpensive.

To summarize, I recommend the following four points be thoroughly discussed and agreed within TECO as you become more serious about running Pet Coke blends in general or this blend in particular at Polk:

- 1) Define the test program and associated costs to demonstrate operability and performance on the blend.
- 2) Carefully consider all environmental, health, and safety aspects of handling Pet Coke and its ash/slag with regard to vanadium. The possibility that the slag may be deemed hazardous, either now or in the future, must be weighed. Also, worker exposure to the slag during operation and maintenance must be minimized whether or not the slag is legally defined as "hazardous". The fine slag will properly pose the greatest environmental, health, and safety challenges.
- 3) Define the capital and operating costs of a fluxing system, and where it should be located (Big Bend or Polk). If fluxing is done at Polk as I recommend, is plot space available?
- 4) What is the best way to turn down the brine concentration unit? Are any equipment modifications likely to be required?

Polk Power Station – Unit 1

IGCC Performance

Rev. 1 – 5/16/94
REV 2 9/15/94

Coal	Pittsburgh 8 Type Coals			Illinois 6 Type Coals			Pet Coke Blends		
	NOC	NOC	NOC	AMAX Del.	Marissa	Old Ben	85% L Kit	25% R Basin	35% FRIER BASIN
Ambient Temp (deg F)	59	90	90	90	90	90	90	90	90
Operation Mode	Normal	Normal	Max Power	Normal	Normal	Normal	Normal	Normal	Normal
Power:									
Gas Turbine	192.0	192.0	192.0	192.0	188.0	188.4	192.0	192.0	192.0
Steam Turbine	122.7	120.6	123.3	125.4	128.6	125.1	118.9	118.8	122.4
Oxygen Plant	(50.2)	(52.6)	(53.0)	(53.6)	(54.8)	(53.9)	(53.3)	(53.4)	53.0
Other Aux Power	(12.2)	(10.9)	(11.9)	(11.2)	(11.4)	(11.3)	(10.9)	(11.0)	11.1
Net Output (MW)	252.4	249.1	251.3	252.7	248.8	248.2	246.8	246.4	250.3
Net Heat Rate (BTU/kWh)	8758	8775	8895	8935	9164	9215	8776	8778	8869
	Notes: Max Power case assumes the plant is operated with low slurry concentration to generate additional MW's at the expense of Heat Rate. NOC coal is based on the Texaco PEP analysis.			Notes: Numbers shaded above are not obtainable with the current plant configuration. Significant capital improvements would be required to operate on these coals. Also, the AMAX coal must be limited to 1% Cl and is marginal in ash.			Notes: For both Blends, the addition of Flux will be required to operate.		

216

PITTSBURGH #8 TYPE COALS

ILLINOIS #6 TYPE COALS

PLT CORE MIXTURES

	TEXACO ISO	TEXACO 90.1 NOC	TEXACO 90.1 CONC NOC	TEXACO 90.1 MED CONC NOC	TEXACO 90.1 EXC CONC NOC
COAL	NOC	NOC	NOC	NOC	NOC
CI (PPMW DRY)	1000	1000	1000	1000	1000
ASH (WT % DRY BASIS)	8.37	8.37	8.37	8.37	8.37
INHERENT MOISTURE (%)	<4.7	<4.7	<4.7	<4.7	<4.7
REDUCING ASH FLOUT (F)	2340	2340	2340	2340	2340
HIV (BTU/B DRY)	13841	13841	13841	13841	13841
FLED (DRY TPD)	1916	1919	1895	1922	1938
FLED (MMBTU/HR)	2210	2214	2186	2217	2236
AMBIENT TEMP (F)	59	90	90	90	90
GASIFIER TEMP (F)	2674	2674	2500	2500	2500
SUDDY % SOLIDS	66	66	66	63.5	62
HSGC FOURING FACTOR	0.042	0.042	0.060	0.060	0.060
POWER					
GAS TURBINE	192.0	192.0	192.0	192.0	192.0
STEAM TURBINE	122.7	125.0	120.6	122.2	123.3
OXYGEN PLANT	50.2	54.3	52.6	52.6	53.0
OTHER AUX POWER	12.2	12.1	10.9	10.9	11.8
NET OUTPUT TO GRID	252.4	250.6	249.1	250.7	251.3
HEAT RATE	8750	8633	8775	8845	8895
OUTPUT LIMITS					
CONSIDERED IN ABOVE ESTIMATES	CI	CI	CI	CI	CI
NOT CONSIDERED IN ABOVE ESTIMATES	NONE	NONE	NONE	NONE	NONE

	AMAX DELTA	MAIRESSA	OLD BEN
1000 - 1500	800	1300	1300
11.35	11.98	10.86	10.86
6.5	10.1	10.5	10.5
2349	2320	2280	2280
12794	12427	12587	12587
2118	2200	2181	2181
2258	2278	2287	2287
90	90	90	90
2500	2500	2450	2450
65	62.5	62.5	62.5
0.040	0.040	0.040	0.040
192.0	188.0	188.4	188.4
125.4	126.8	125.1	125.1
53.5	54.6	53.9	53.9
11.2	11.4	11.3	11.3
252.7	248.6	248.2	248.2
8935	9164	9215	9215
CI	CHARGE PUMP, ASU	CHARGE PUMP	CI
(BIRNE) (ASU)	FLYASH SI AG (SUDDY) (AGI)	BIRNE FLYASH SI AG (AGI) (SUDDY)	NONE (SIR)

	35% LOWER KITTANING	25% RATION BASIN	35% POWER H RIVER BASIN
1000	1000	800	350
3.68	2.48	2.36	2.36
5	4	11.7	11.7
2680*	2530*	2340	2340
14985	15163	14428	14428
1745	1719	1847	1847
2167	2165	2220	2220
90	90	90	90
2500	2500	2500	2500
65	65	62	62
0.060	0.060	0.06	0.06
192.0	192.0	192.0	192.0
118.9	118.8	122.4	122.4
53.3	53.4	53.0	53.0
10.9	11.0	11.1	11.1
246.8	246.4	250.3	250.3
8776	8778	8869	8869
CI	CI	CI	CI
NONE (SIR)	NONE (SIR)	NONE	NONE

NOTE (xxx) INDICATES MARGINAL CONSTRAINT
* INDICATES THAT FLUX WAS ADDED

GASIFIER EXH SOLIDS (TPD)	182.76	183.12	202.44	202.2	206.76	285.96	310.44	294.6	107.3	87.8	90.2
% OF FLYASH DESIGN	66.2	66.3	73.3	74.3	74.9	103.6	112.5	106.7	38.9	31.8	32.7
% OF LOCKHOPPER DESIGN	66.6	66.8	95.9	97.3	98.0	135.5	147.1	139.6	50.8	41.6	42.8
FLYASH DESIGN BASIS IS 276 TPD LOCKHOPPER DESIGN BASIS IS 211 TPD											
SIR											
MOISTURE CORRECTION	540	541	534	535	534	677	799	791	519	521	650.2
% OF DESIGN	65.5	65.6	64.7	72.3	76.8	82.1	90.8	90.9	62.9	63.2	78.8
% OF AGI DESIGN	68.7	68.8	67.9	75.7	80.7	86.1	101.7	100.6	66.0	66.3	82.7

ACID PLANT DESIGN BASIS 800
SIR DESIGN IS 786

0.0015

4

5

PITTSBURGH #8	0.00%
POWDER RIVER	35.00%
INDONESIAN	0.00%
PET COKE	65.00%
HATON BASIN	0.00%
LOWER KITTANNING	0.00%

NOTE: inherent moisture values are assumed

TOTAL 100.00%

	PIT #8	POWDER RIVER	INDONESIAN	PET COKE	HATON BASIN	LOWER KITTANNING	
SLIGHT PROXIMATE							15.20%
% MOISTURE, AS REC	4.74%	27.53%	22.11%	8.89%	4.41%	8.20%	11.70%
% MOISTURE, DRIER	4.00%	26.00%	16.60%	4.00%	4.00%	7.00%	1.97%
% ASH	7.88%	5.14%	0.59%	0.26%	9.31%	7.50%	12.21%
BTU/LB	13,290	8,802	9,937	14,164	13,260	13,060	3.14%
% SULFUR	2.45%	0.34%	0.05%	4.65%	0.40%	1.30%	18.98%
% VOLATILE	36.31%	32.99%	37.92%	11.32%	31.51%	29.80%	63.84%
% FIXED CARBON	51.07%	34.34%	39.38%	79.73%	54.77%	54.50%	4.86
LBS SO ₂ /MMBTU	3.50	0.73	0.10	6.24	0.57	1.90	
ULTIMATE							15.20%
% MOISTURE	4.74%	27.53%	22.11%	8.89%	4.41%	8.20%	70.32%
% CARBON	73.76%	50.54%	57.58%	60.97%	74.33%	72.08%	3.74%
% HYDROGEN	4.72%	3.58%	3.93%	3.84%	5.14%	4.68%	1.20%
% NITROGEN	1.39%	0.68%	1.01%	1.48%	1.47%	1.47%	0.03%
% CHLORINE	0.10%	0.01%	0.01%	0.04%	0.17%	0.18%	3.14%
% SULFUR	2.45%	0.34%	0.08%	4.65%	0.40%	1.10%	1.97%
% ASH	7.88%	5.14%	0.59%	0.26%	9.31%	7.53%	4.34%
% OXYGEN	4.96%	12.20%	14.69%	0.11%	4.77%	3.86%	
ASH MELTAL							26.07%
SiO ₂	42.95%	30.40%	14.48%	10.30%	45.11%	46.70%	14.64%
Al ₂ O ₃	22.46%	15.80%	11.81%	2.24%	24.75%	29.60%	1.31%
Fe ₂ O ₃	1.09%	1.30%	0.56%	1.40%	1.45%	1.40%	5.48%
CaO	17.51%	5.40%	16.26%	6.28%	6.33%	13.60%	21.80%
MgO	5.40%	22.90%	15.17%	10.04%	9.15%	3.00%	4.65%
K ₂ O	1.08%	4.90%	5.37%	1.98%	3.07%	0.60%	0.36%
Na ₂ O	1.32%	0.30%	0.72%	1.04%	0.30%	1.40%	1.44%
SO ₃	0.86%	1.20%	0.18%	3.96%	1.53%	0.20%	16.14%
P ₂ O ₅	4.22%	15.40%	24.07%	24.01%	5.68%	2.80%	0.94%
VO ₂	0.43%	1.00%	0.14%	0.30%	0.85%	0.40%	2.68%
ASH FUSION (REDUCING)							21.21
INITIAL DEFORMATION	2100	2100	2360	2350	2190	2475	2252
SOFTENING	2150	2240	2400	2385	2430	2580	2272
HEMISPHERICAL	2230	2260	2420	2405	2490	2680	2318
FLUID	2340	2330	2480	2425	2540	2700	

CCG

218

May 16, 1994

To: D. E. Pless

From: D. A. Cowdrick

Subject: Updated Polk Performance Estimates

In response to your request for updated performance estimates for Polk Unit 1, we have prepared several tables and have also attached backup information documenting the data presented. Most of the data presented are for the plant in the current configuration operated in IGCC mode. We have also provided estimates of performance for the plant operated on natural gas and on distillate oil.

Table 1 summarizes the performance on different coals or blends in the IGCC mode of operation. These numbers are very similar to the last set of performance estimates presented for the plant (Ref. 9/17/93 memo D. A. Cowdrick to D. E. Pless). The composition assumed for the Pet Coke/Coal blends was provided by our Fuels department. The Illinois 6 cases presented include the AMAX delta coal we have looked at previously and two additional coals we have modeled in recent months. ~~The Marissa and Old Ben coals are not suitable fuels based on the current plant configuration. However, with certain capital improvements, we feel the plant could be configured to operate on these fuels (Ref. 4/11/94 memo D. A. Cowdrick to S. D. Jenkins for additional information).~~

Table 2 summarizes the performance for operating in either combined cycle or simple cycle mode on natural gas or distillate oil. ~~The basis for these numbers assumes utilizing the existing Polk equipment with minimal capital modifications. It should be noted that for both cases (gas and oil), capital modifications would be required to operate.~~

Also attached to this package is a curve relating Heat Rate to Net Power Output for the plant operated in IGCC mode. ~~The amount of turndown that can be achieved is still an open issue. The curve presented assumes a minimum of 60% fuel flow through the gasifier. Texaco has stated we should go no lower than 80% fuel flow to maintain acceptable velocities in the syngas cooling system. We have assumed we can go down to 60% based on our own review. For outputs below those associated with this 60% flow, it is assumed that excess fuel would be flared which is not acceptable from a permitting standpoint at this time. Operation in this mode is~~

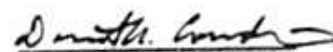
Page 2 - 5

still being investigated. We are also still investigating the ability to turndown to the estimated 60% level. If this can not be achieved, the Heat Rates predicted for outputs in the 125 MW thru 175 MW range would be significantly higher.

Finally, presented below is an estimate of the plants Equivalent Availability in IGCC mode for the early years of operation. This estimate does not include seasonal deratings or any credit for operation on backup-fuel (distillate Oil). The numbers presented are very subjective and are primarily based on experience from Cool Water. We have also considered information we have available from other gasification projects and known improvements to the Texaco process since the Cool Water project. Backup data attached from Cool Water suggests we could experience significant availability impacts from syngas cooler plugging and from alternate coal tests in these early years of operation.

<u>Period</u>	<u>EAF</u>
2nd half '96	50%
1st half '97	60%
2nd half '97	65%
1st half '98	70%
2nd half '98	75%
remaining years	80%

If you need any additional information or if you would like to discuss the data in more detail, please contact me. .


D. A. Cowdrick

MRC

cc: C. Shelnut
T. Hernandez
J. McDaniel
M. Grant
W. Maye
File TPH1

Polk Power Station - Unit 1 IGCC Performance

Coal	Pittsburgh 8 Type Coals			Illinois 6 Type Coals			Pet Coke Blends	
	NOC	NOC	NOC	AMAX Del.	Marissa	Old Ben	35% L. Kit.	25% R. Basin
Ambient Temp (deg F)	59	90	90	90	90	90	90	90
Operation Mode	Normal	Normal	Max Power	Normal	Normal	Normal	Normal	Normal
Power:								
Gas Turbine	192.0	192.0	192.0	192.0	188.0	188.4	192.0	192.0
Steam Turbine	122.7	120.6	123.3	125.4	126.6	125.1	118.9	118.8
Oxygen Plant	(50.2)	(52.6)	(53.0)	(53.5)	(54.6)	(53.9)	(53.3)	(53.4)
Other Aux Power	(12.2)	(10.9)	(11.9)	(11.2)	(11.4)	(11.3)	(10.9)	(11.0)
Net Output (MW)	252.4	249.1	251.3	252.7	248.6	248.2	246.8	246.4
Net Heat Rate (BTU/ kWh)	8758	8775	8895	8935	9164	9215	8776	8778
Notes: Max Power case assumes the plant is operated with low slurry concentration to generate additional MW's at the expense of Heat Rate. NOC coal is based on the Texaco PEP analysis.				Notes: Numbers shaded above are not obtainable with the current plant configuration. Significant capital improvements would be required to operate on these coals. Also, the AMAX coal must be limited to 1% Cl and is marginal in ash.			Notes: For both Blends, the addition of Flux will be required to operate.	

Page 4

TABLE 2
Natural Gas and Distillate Operation

	NET OUTPUT MW	NET HEAT RATE BTU/KWH LHV
59 Deg F.		
Simple Cycle		
GAS	159.0	10100
OIL	160.1	10458
Combined Cycle		
GAS	233.1	6909
OIL	231.1	7181
90 Deg F.		
Simple Cycle		
GAS	140.9	10503
OIL	141.3	10792
Combined Cycle		
GAS	212.4	7000
OIL	210.1	7195

PAGE 5 of 7

IGCC PLANT TURNDOWN - LOAD vs HEAT RATE
J. McDaniel 5/13/94

There are three key ranges of interest when considering the relationship between plant load and heat rate:

1) High Load Range

Plant Load: 75% - 100%
Gasifier Load: 80% - 100%
Plant Net Output: 187.5 MW - 250 MW
Gas Turbine Output: 140 MW - 192 MW
Net Heat Rate: 9325 - 8775 BTU/KWH

In this region:

a) The gas turbine compressor's inlet guide vanes are modulating, so the turbine can be turned down with relatively low efficiency penalty.

b) The oxygen plant's main compressor inlet guide vanes are modulating, so they can be turned down with relatively low efficiency penalty.

c) The gasifier's carbon conversion is relatively constant, so its efficiency is unimpaired with turndown.

d) The IP turbine's extraction steam pressure is sufficiently high to provide LP steam to the process plant's reboilers.

2) Intermediate Load Range

Plant Load: 50% - 75%
Gasifier Load: 60% - 80%
Plant Net Output: 125 MW - 187.5 MW
Gas Turbine Output: 100 MW - 140 MW
Net Heat Rate: 11040 - 9325 BTU/KWH

In this region:

a) The combustion turbine compressor's inlet guide vanes continue to modulate, so the turbine can continue to be turned down throughout this region with relatively low efficiency penalty.

b) The oxygen plant compressors have reached their surge point under inlet guide vane control, so they must vent any excess gas. Efficient turndown of the air plant is not possible in this region.

c) The gasifier's carbon conversion begins to deteriorate, and syngas cooler fouling becomes progressively worse with the lower velocities. Gasification area efficiency begins to suffer in this region.

d) The steam turbine's LP extraction pressure is too low to meet process requirements, so MP steam must be let down.

2026

IGCC Plant Turndown (Continued)

3) Low Load Range

Plant Load: 0% - 50%

Gasifier Load: 60%

Plant Net Output: 0 MW - 125 MW

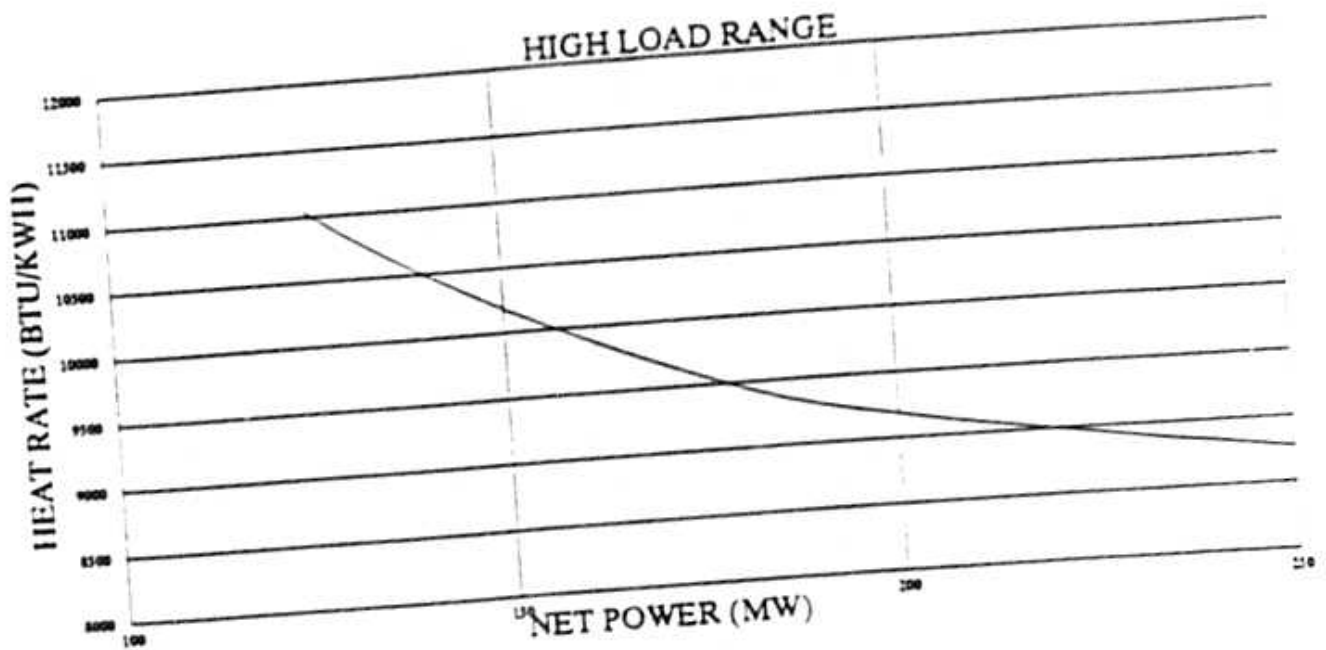
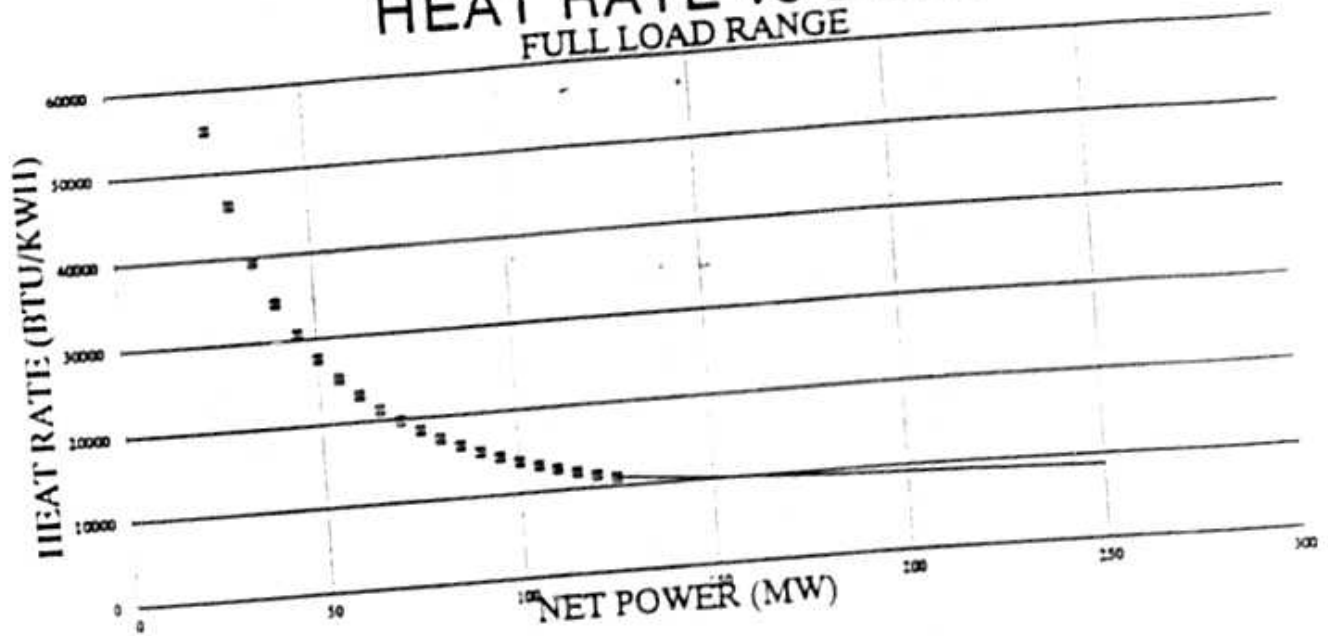
Gas Turbine Output: 25 MW - 100 MW

Net Heat Rate: Infinite - 11040 BTU/KWH

The overriding consideration in this region is the fact that this is at the lowest practical turndown point for the gasifier. Below 60% gasifier load, carbon conversion deteriorates rapidly, syngas cooler fouling becomes extremely heavy and possibly non-recoverable due to the low velocities, and many control valves are at the limit of their stable control range. Consequently, for any plant, turndown below about 125 net MW, the gasifier must continue to be operated at about 60% load and the excess syngas must be flared.

HEAT RATE vs LOAD

FULL LOAD RANGE



APPROXIMATE HEAT RATE vs POWER CORRELATIONS:

$$\text{HEAT RATE (BTU/KWH)} = A + B/\text{POWER (MW)}$$

LOAD RANGE:

NET PLANT MW

187.5 - 250.0

125.0 - 187.5

0.0 - 125.0

A

7105

5893

0

B

415,928

643,320

1,380,000

225

**TAMPA ELECTRIC COMPANY
DOCKET NO. 960409-EI
FPSC STAFF'S 1st SET
INTERROGATORY NO. 20
WITNESS: BLACK
PAGE 1 of 1**

20. Please identify each person who participated in TECO's decision that pet coke is a viable fuel for the IGCC facility as detailed in its response to Staff's Interrogatory No. 3, in Docket No. 950379-EI.
- A. The individuals participating in the final decision that pet coke is a viable fuel for the IGCC facility were Thomas Hernandez, Hugh Smith, William Cantrell, and Charles Black.

31. Please explain in detail the improvements required to the Big Bend loading facility for transloading fuel from barge to truck for the Polk County IGCC? Include in your response an itemized list of each improvement, its estimated cost, its completion date, whether the improvement is specific to the fuel for the Polk County IGCC, and whether the improvement can facilitate transloading bulk materials for other utilities and companies.
- A. A transloading facility was constructed at Big Bend for transloading fuel from barge to truck for the Polk County IGCC through turnkey construction packages, at a cost of \$3.04M net of DOE co-funding as furnished in Docket No. 950379-EI, Staff's Second Set Interrogatory No. 16. The project includes the following improvements:
- 1) Added division wall to north blending bin.
 - 2) Changed out the drive sprockets on both north blending bin feeders to double capacity to 2,000 tons per hour.
 - 3) Added new load-out conveyor complete with motor and gear reducer and belt.
 - 4) Added new load-out structure with:
 - a) nominal 30-ton weigh bin with load cells
 - b) load-out chute and gate with hydraulic control unit; complete
 - c) complete automatic control system for the system
 - d) fire protection system
 - e) motor control center and electrical panels
 - f) all required cable, conduit, and electrical components
 - g) all exterior structural lighting and control room lighting
 - h) wash-down piping, valves and hose reels
 - i) field instrumentation for the load-out conveyors, weigh bin, hydraulic system, and the automated load-out system
 - j) truck wash facility
 - k) additional computer for the blending bin control room to monitor operations
 - l) card reader to be located at the Polk Station
 - m) all necessary interfacing for data links between Polk, Big Bend, and Tampa Electric main office
 - 5) Additional roadway, lighting, guardrails, and traffic controls.
 - 6) Pond and drainage reconfigurations to accommodate coal field and site run-off.
 - 7) Equipment/structural piling and foundation.

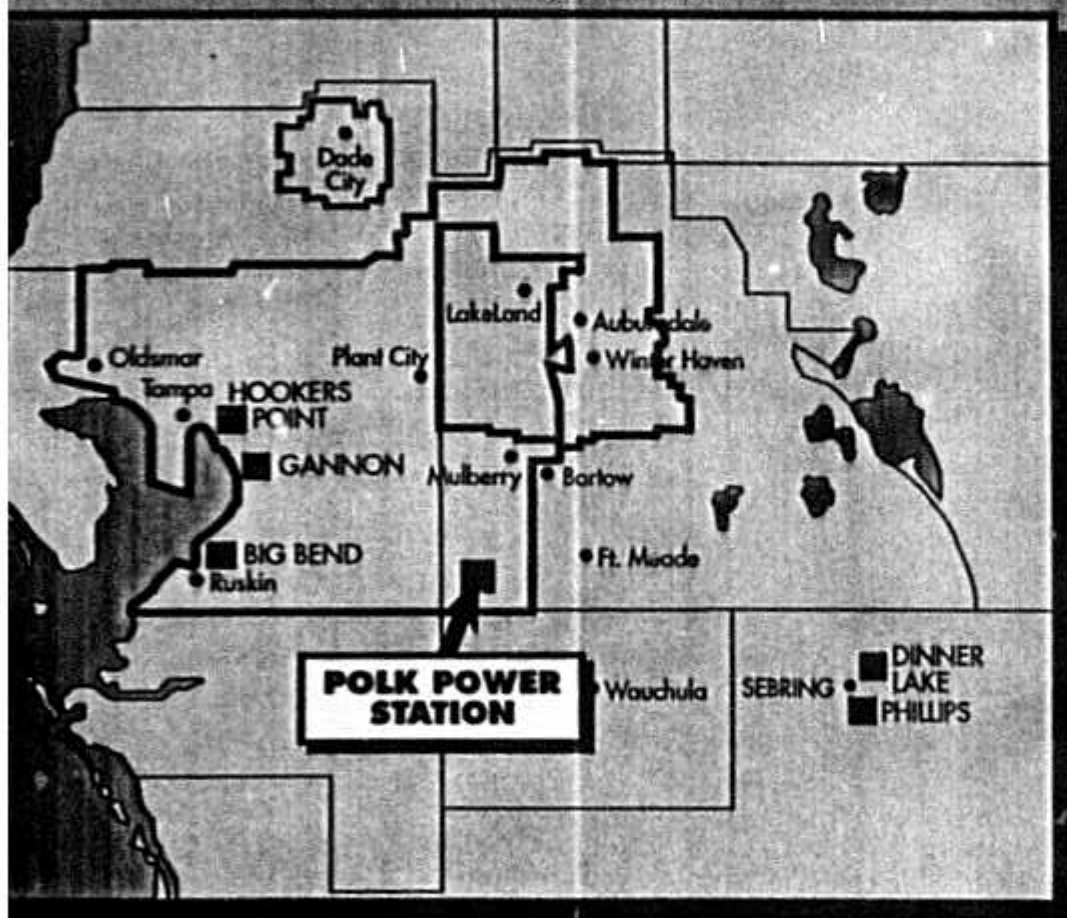
The completion date for the Big Bend transloading equipment was March, 1996. This transloading equipment is specific to fuel transloading for the Polk County IGCC project, but the improvements can also facilitate limited transloading of bulk materials for other utilities and companies.

TAMPA ELECTRIC COMPANY
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EXHIBIT NO. ____ (CRB-1)
DOCUMENT NO. 13
PAGE 1 OF 3

DOCUMENT NO. 13

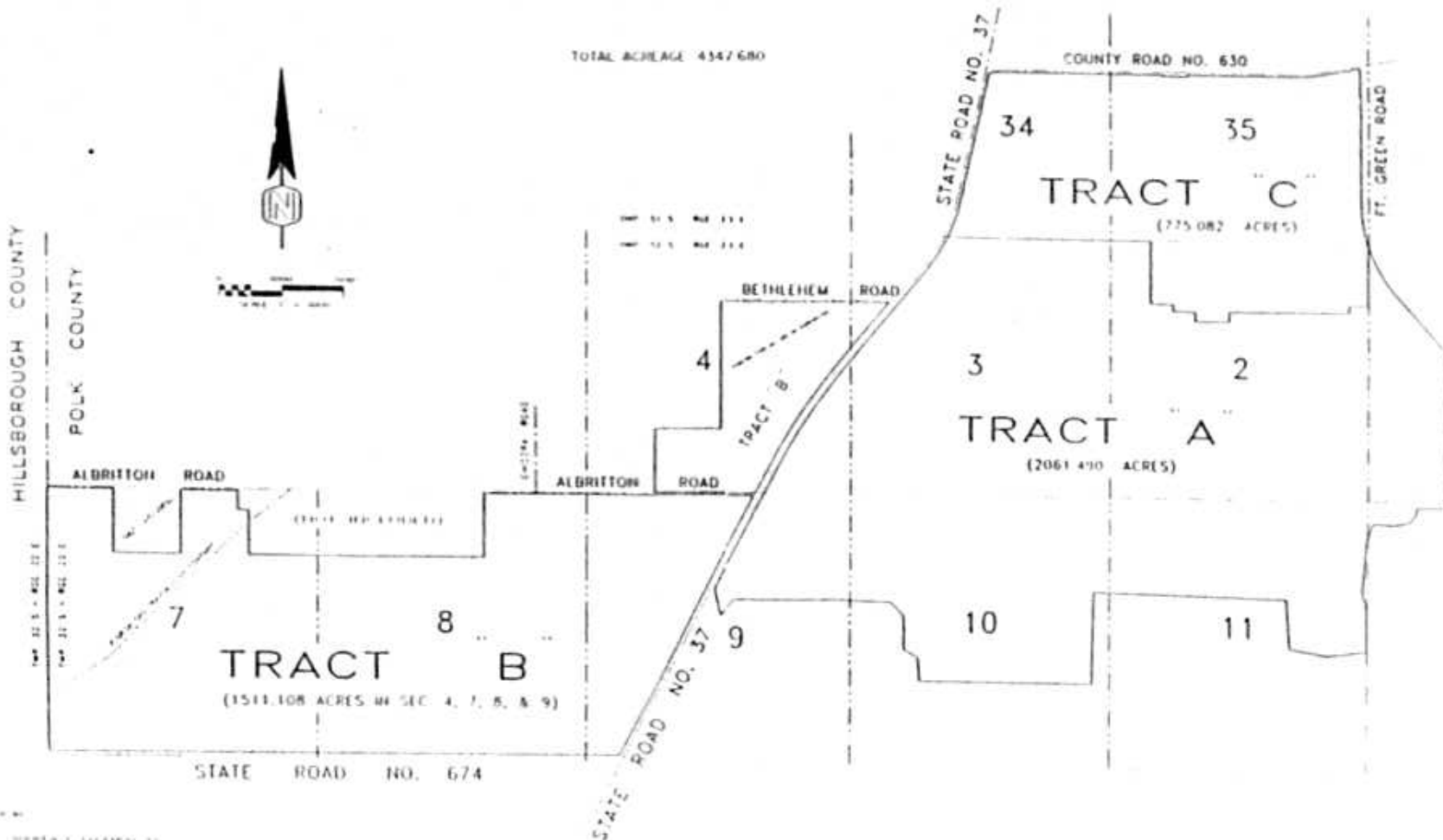
POLK SITE MAP

Polk Power Station



PROPOSED POLK POWER STATION SITE

TOTAL ACRES 4547.680



230

APPROVED FOR RECORD BY
NOTARY PUBLIC
COUNTY OF POLK, IOWA
JAMES M. WATSON, Notary
My Comm. Expires 12/31/2010
FILED 12/14/2010

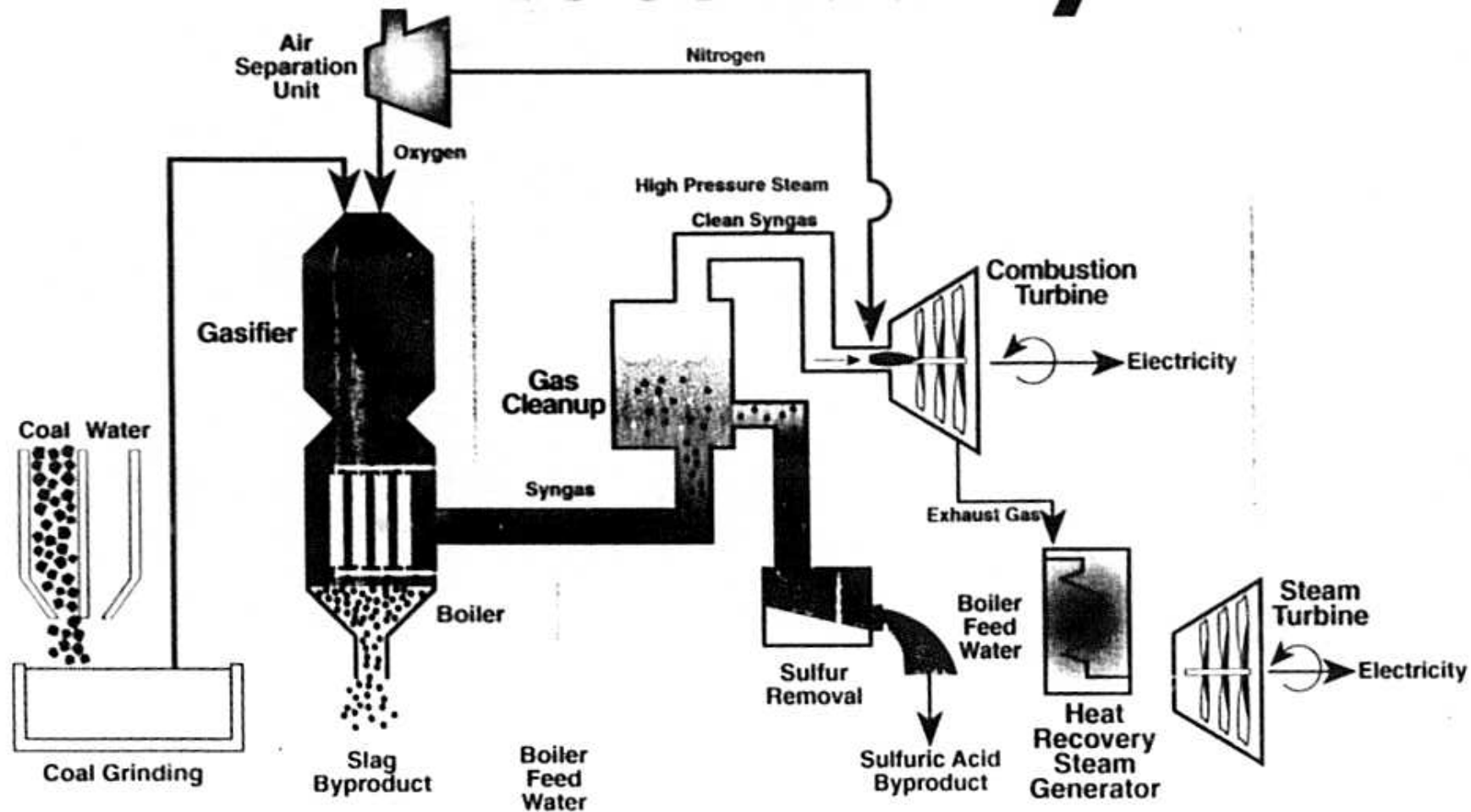
DATE	TIME	BY
12/14/2010	10:00 AM	JAMES M. WATSON

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DOCUMENT NO. 14
PAGE 1 OF 2

DOCUMENT NO. 14

POLK IGCC TECHNOLOGY DIAGRAM

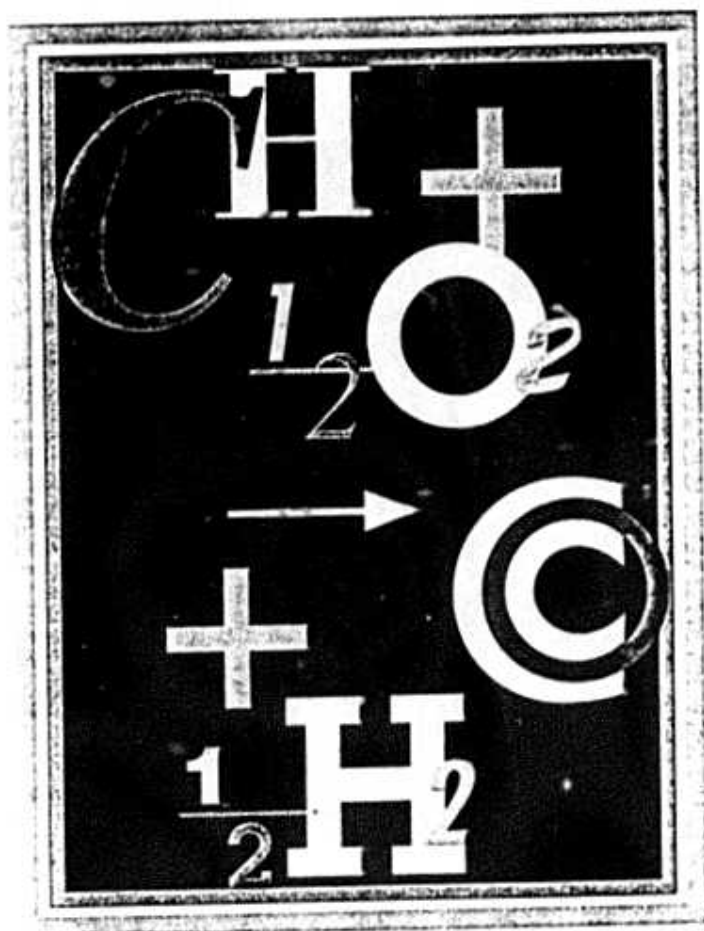
IGCC Facility



TAMPA ELECTRIC COMPANY
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WITNESS: BLACK
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PAGE 1 OF 12

DOCUMENT NO. 15

TEXACO GASIFICATION PROCESS



*Texaco
Gasification
Process
for Solid
Feedstocks*

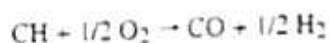
Over the last 35 years, the Texaco Gasification Process (TGP) for Solid Feedstocks has been licensed in more than 15 commercial facilities to manufacture synthesis gas (Syngas). Primarily hydrogen and carbon monoxide, this synthesis gas is a basic building block for many agricultural and chemical industry applications. It may be used for:

- Chemical synthesis of ammonia, methanol and oxochemicals
- Hydrogen manufacture
- Electricity production
- Fuel for industrial boilers and process heaters
- Reducing Gas for metallurgical applications

Feedstock flexibility and high operating reliability are among the technology's major advantages. Many different solid feedstocks, such as coal and petroleum coke, have been gasified using this process. Many plants run on a mixture of feedstocks and most can switch feedstocks without interrupting operations. Some even use hydrocarbon-containing byproducts from other operations. This technology easily meets the most rigorous environmental standards. The process is proven to be reliable, flexible and adaptable to the ever-changing needs of the worldwide refining, chemical and power generation industries.

The Gasification Processes described in this brochure apply only to solid feedstocks. For information regarding gasification of liquid and gaseous feedstocks, ask your Texaco Representative about other literature available.

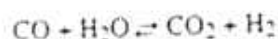
The Texaco Gasification Process for Solid Feedstocks is a non-catalytic, continuous, entrained flow, partial oxidation process. Under the TGP, carbonaceous solids react at high temperature and usually at high pressure with oxygen, oxygen-enriched air, or air according to the basic overall reaction:



Although the detailed chemistry and thermodynamics of partial oxidation technology are very complex, valuable insight can be gained by considering two additional concurrent reactions: the complete oxidation of the hydrocarbon to carbon dioxide (CO_2) and water



and the reversible water-gas shift reaction,



Both reactions are exothermic and generate very high temperatures within the reactor. These conditions necessitate the use of a temperature moderator (such as water, steam, or carbon dioxide) to simultaneously control temperatures at appropriate levels and to optimize the hydrogen to carbon dioxide ratio for downstream chemical synthesis.

The raw product gas contains principally carbon monoxide (CO) and hydrogen (H_2). Also present are some carbon dioxide (CO_2) and steam, plus trace amounts of argon, nitrogen, methane and (if the feed contained sulfur) hydrogen sulfide and carbonyl sulfide. No heavy hydrocarbons, tar or other potentially troublesome by-products are formed. Typical synthesis gas compositions are shown for various feedstocks in Table 1. Because the gasifier operates at elevated temperatures in a highly reducing atmosphere, it leaves neither oxides of sulfur nor nitrogen in the product gas.

TABLE 1 SYNGAS PRODUCTION FROM VARIOUS CARBONACEOUS FEEDS

FEED TYPE	COAL					PETROLEUM COKE		COAL LIQUEF. RESIDUE	
	PITTSB. NO. 8	FRENCH	UTAH	GERMAN	S. AFRICAN	DELAYED	FLUID	MOLTEN	SLURRY
Feedstock Dry									
Anal., wt. Pct									
Carbon	74.16	78.08	68.21	73.93	65.60	38.50	55.98	68.39	68.39
Hydrogen	5.15	5.26	4.78	4.65	3.51	3.90	2.00	4.75	4.75
Nitrogen	1.18	0.85	1.22	1.50	1.53	1.50	0.98	0.98	0.98
Sulfur	3.27	0.47	0.37	1.08	0.87	5.50	8.31	1.87	1.87
Oxygen	6.70	8.23	15.69	5.85	7.79	0.10	2.27	2.21	2.21
Ash	9.54	7.11	9.73	13.01	20.70	0.50	0.46	21.50	21.50
Higher Heating Value									
Btu/lb	13,600	14,000	11,800	13,200	11,200	15,400	13,800	12,700	12,700
Kcal/kg	7,540	7,780	6,570	7,330	6,220	8,550	7,665	7,060	7,060
Product Composition									
Mol Pct									
Carbon Monoxide	39.95	37.36	30.88	39.46	36.53	46.20	47.14	46.31	33.48
Hydrogen	30.78	29.26	26.71	29.33	26.01	28.69	24.33	35.54	28.56
Carbon Dioxide	11.43	13.30	15.91	12.59	15.67	10.68	13.16	6.41	13.09
Water	16.43	19.43	25.67	17.47	20.82	12.37	12.67	10.46	23.72
Methane	0.04	0.16	0.22	0.25	0.02	0.17	0.09	0.27	0.23
Nitrogen & Argon	0.49	0.37	0.50	0.60	0.68	0.55	0.42	0.45	0.42
Hydrogen Sulfide & Carbonyl Sulfide	0.58	0.12	0.11	0.20	0.27	1.74	2.19	0.56	0.50

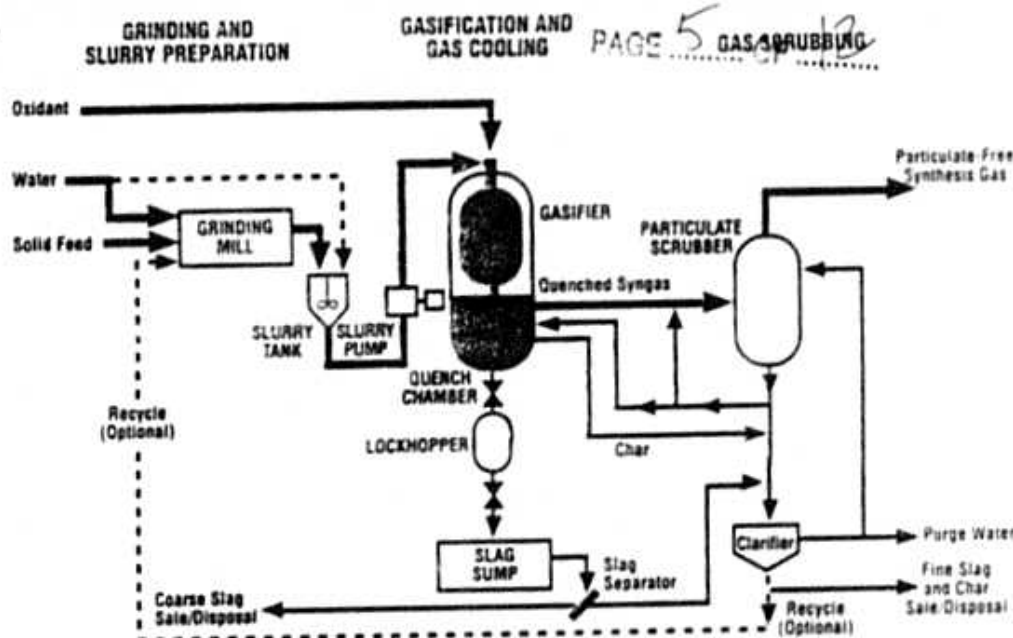


FIG. 1 COAL & OTHER SOLIDS - DIRECT QUENCH MODE

The feedstock is typically wet-ground in conventional grinding mills and slurried with water to create concentrations normally greater than 65 weight percent. Therefore, energy-intensive drying of the solid feed is not necessary. Wet grinding eliminates dust control systems and explosion hazards. The slurry feed system provides greater operational simplicity and control even when high pressure gasification is employed. The slurry is fed simultaneously with oxygen or air to the gasifier through a burner. The water in the slurry serves as a transport medium and temperature moderator.

The hot gas exiting the gasifier is cooled directly in a quench chamber by contact with water or indirectly in a syngas cooler (waste heat boiler) to recover excess heat/energy. Plants using these cooling modes have been operational for many years. The desired fuel specification range, level of integration with other facilities, and ultimate end-use of the syngas generally determine the preferred mode of gas cooling.

In the direct quench mode (Figure 1), the hot gas exiting the gasifier contacts water in the quench chamber which is located in the bottom of the gasifier vessel. The raw gas is cooled and saturated with steam. This mode is preferred for production of high purity hydrogen and, when properly integrated into the remainder of the facilities, is efficient for electric power generation. The direct quench mode is considered to be a waste-management gasifier, because it can convert low-value waste and refinery streams to synthesis gas. The direct quench mode offers a significant investment savings and yet provides a highly efficient method of raising process steam for downstream uses (e. g. shifting to hydrogen, saturation of fuel gas).

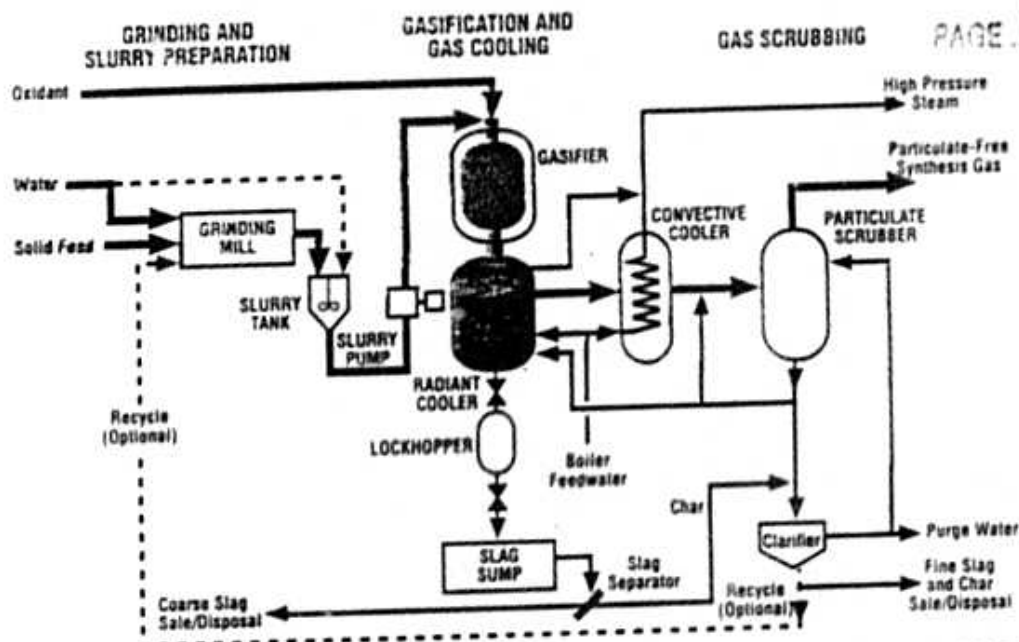


FIG. 2 COAL & OTHER SOLIDS - GAS COOLER MODE

In the syngas cooler mode (Figure 2), hot gas is indirectly cooled in a specifically designed syngas cooler where high pressure export steam is generated. If desired, additional gas cooling is possible in an economizer. This mode of cooling is preferred for the manufacture of fuel gas, reducing gas, power generation and other petrochemical applications. It is selected when shift conversion is not required and where recovery of excess heat in the synthesis gas is desired to maximize energy efficiency.

Gas Scrubbing

The cooled or saturated raw synthesis gas from the gasifier is water-scrubbed in a soot scrubber. This removes essentially all traces of entrained particles, principally unconverted carbon, ash and metals. This soot-scrubbing equipment, using several stages of particulate removal, has many years of commercial application.

Ash Removal

Most of the ash is removed as a solid, glass-like slag through a water-sealed, depressurizing lockhopper system. This material is moved to a collection sump where it is separated from the water for further handling. The fines in the water are pumped from the sump and routed as a dilute slurry to the clarifier for gravity separation or filtration. The scrubbing water stream is also sent to a clarifier for removal of entrained char particles. The return of clarifier overflow to the gas scrubber conserves water. A fraction of the water may be purged from the system to control the level of dissolved solids and to prevent scaling in the water system. The clarifier concentrates the char and fine slag in the underflow for further handling or recycling.

All ranks of coals, petroleum cokes and coal liquefaction residues may be gasified by the Texaco Gasification Process for Solid Feedstocks. Table 2 lists some types of feedstocks gasified at Texaco's TGP Pilot Plants in Montebello, California. The Ube Ammonia Coal Gasification Plant in Ube City, Japan, imports coal and coke as feedstock and has demonstrated commercial flexibility on a wide variety of solid feeds as shown in Table 3.

Any carbonaceous solid that can form a pumpable, concentrated slurry with water is a suitable feedstock. Additives may be used to enhance the slurring properties of some feedstocks.

Commercial applications of the Texaco Gasification Process for solid carbonaceous feedstocks were the direct result of over forty years of experience with partial oxidation using gaseous and liquid feeds. Results are supported by the construction and operation of a series of pilot, demonstration and commercial plants, some of which are listed in Table 4. The data obtained from these units provides the basis for design and insures the reliable operation of commercial plants for different applications.

TABLE 2 EXAMPLES OF FEEDSTOCKS GASIFIED IN THE TEXACO MONTEBELLO PILOT PLANTS

COAL	PETROLEUM COKE
• Anthracite	• Fluid
• Semi-anthracite	• Delayed
• Bituminous	• Calcined
• Sub-bituminous	• Fluid coke from tar sands bitumen
• Lignite	
COAL LIQUEFACTION OTHER RESIDUE	
• Solvent Refined Coal Residue (SRC I & II)	• Lurgi tar/oil
• H-Coal Residue	• Sewage sludge
• Exxon Donor Solvent (EDS) Residue	• Waste oils

TABLE 3 UBE AMMONIA PLANT

COAL:	Australian Coal
	Chinese Coal
	South African Coal
	Canadian Coal
	Colombian Coal
	Petroleum Coke
CAPACITY:	1,650 tons of coal per day
PRODUCT:	Ammonia/Urea
BY-PRODUCTS:	Sulfur - Commodity sales
	Slag - To cement plant
	CO ₂ - To bottling plant

TABLE 4 TGP PLANT SUMMARY

OWNER	TYPE	LOCATION	COAL CAPACITY	START-UP	HEAT RECOVERY	PRODUCT
Texaco Inc.	Pilot	California	15 TPD	1973	Direct Quench	R&D
Texaco Inc.	Pilot	California	15 TPD	1978	D.Q./Gas Cooler	R&D
Tennessee-Eastman	Commercial	Tennessee	900 TPD	1983	Direct Quench	Acetic Anhydride
Cool Water	Commercial	California	1,000 TPD	1984	Gas Cooler	Electric Power
Ube Ammonia	Commercial	Japan	1,650 TPD	1984	Direct Quench	Ammonia
SAR	Commercial	Germany	800 TPD	1986	D.Q./Gas Cooler	Oxo-Chemical/Hydrogen
Lunan	Commercial	China	400 TPD	1992	Direct Quench	Ammonia
Shougang	Commercial	China	1,100 TPD	1994	Gas Cooler	Fuel Gas
Weihe	Commercial	China	1,650 TPD	1996	Direct Quench	Ammonia
Shanghai	Commercial	China	1,100 TPD	1996	Gas Cooler	Town Gas/Chemicals

Figures 3 and 4 depict the Texaco Gasification Power Systems (TGPS) in the quench and full heat recovery mode. These involve the commercially proven integration of Texaco's gasification technology with an Integrated Gasification Combined Cycle (IGCC) power plant.

Optimization of individual units and subsystems – especially cost-effective use of low-level heat – is fundamental to superior heat rate performance of TGPS IGCC

applications. Early IGCC configurations used syngas moisturization and later configurations used simple nitrogen injection for NO_x control prior to feeding the combustion turbine. In contrast, TGPS allows for nitrogen preheating, nitrogen moisturization and higher levels of syngas moisturization.

TGPS is not limited to specific technology selections related to oxygen plant, sulfur plant, or power plant suppliers and can operate either in the syngas cooler or in the quench

gasification configuration. Because of technological flexibility, TGPS allows a wide variety of choices in power plant feedstock (coal, petroleum coke, orimulsion, heavy oil, wastes) without sacrificing plant performance or compromising environmental permits.

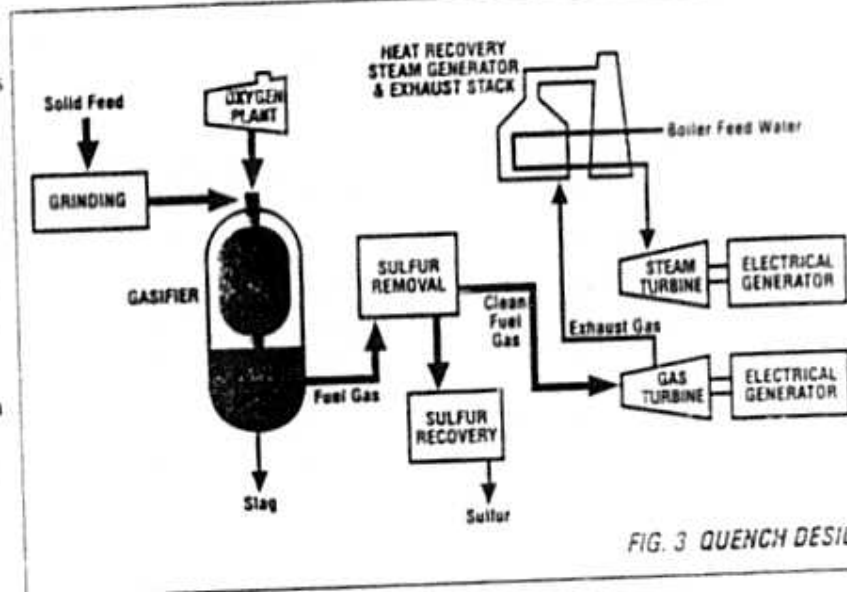


FIG. 3 QUENCH DESIGN

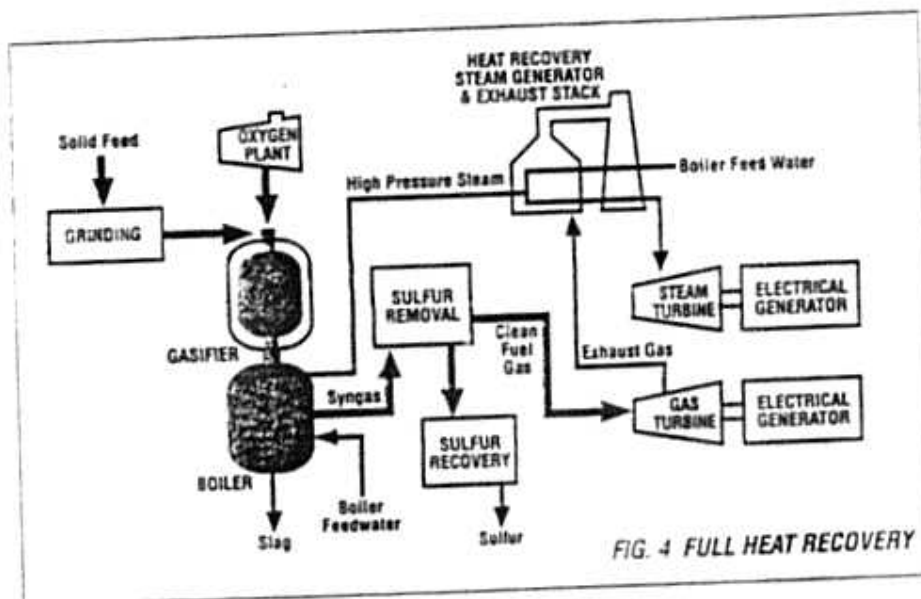


FIG. 4 FULL HEAT RECOVERY

PAGE 9 OF 12

The unique features of the Texaco Gasification Process for Solid Feedstocks make it attractive to numerous potential users. Its key strengths are:

Feedstock Flexibility

The process is relatively insensitive to solid feedstock properties such as particle size, moisture level, reactivity and caking. This permits the use of the most economical feedstock available at a given time.

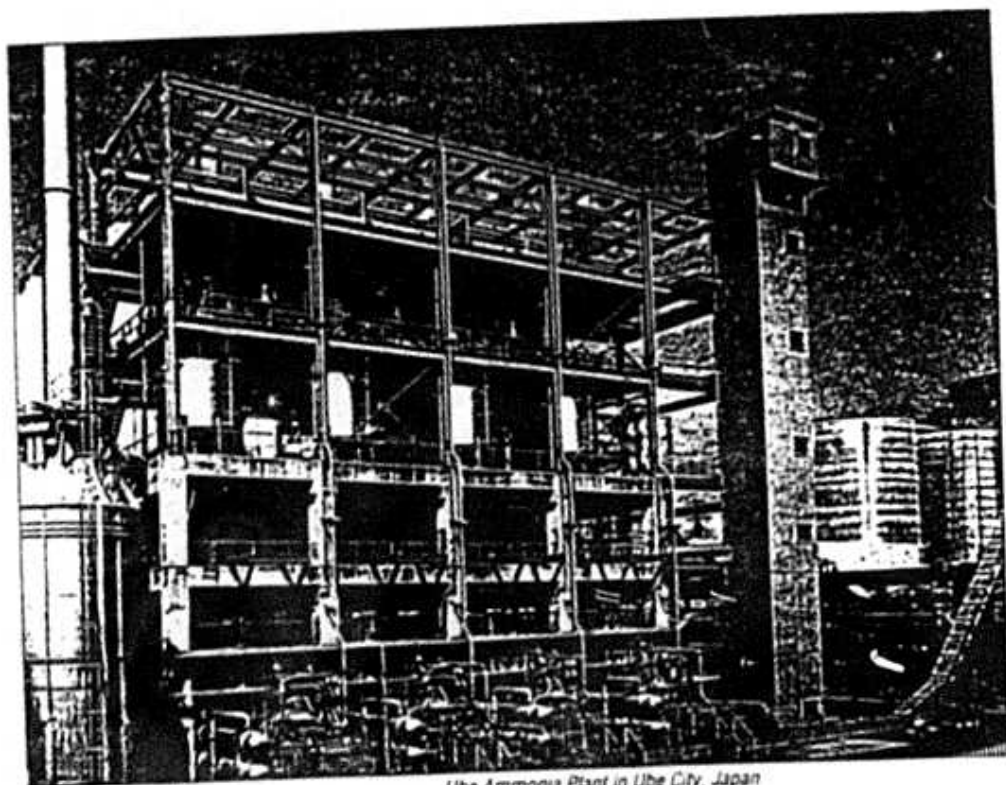
Simplicity and Reliability

The gasifier has no moving parts. Its burner is easy to remove and replace quickly and requires no gasifier cool down. The slurry feed system is patterned after the liquid hydrocarbon feed system and is proven to be highly safe and reliable. A

provision for slurry storage allows minor repairs to slurry preparation equipment without process interruption. This system efficiency reduces labor and supervision requirements.

Throughput, Turndown and Load Following

High operating temperatures generate a nearly complete carbon conversion to synthesis gas in seconds. Short residence time and high-pressure capability yield high feed throughput and gas production in moderate-sized process equipment. This reduces plant area requirements and capital costs. The superb load following characteristics even match requirements for refining, chemical and power generation applications. Single train turndowns of 50% of design capacity are typically achieved with no significant effect on equipment or performance.



Ube Ammonia Plant in Ube City, Japan

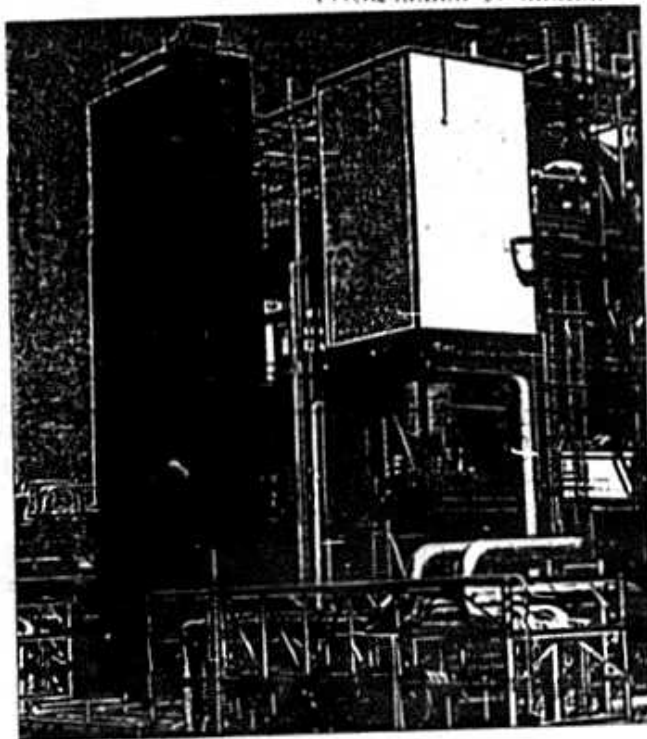
Process Efficiency

Nearly complete conversion of the feed to product gas can be accomplished in a single pass. For complete conversion, the high-carbon fraction of the rejected solids may be recovered and recycled to the gasifier. Gas stream sensible heat is recovered by either direct quenching or indirect gas cooling.

Environmental Aspects

The high reaction temperature eliminates the formation of hydrocarbons heavier than methane. When cooled, molten slag from the gasifier forms hard glassy particles which are low in carbon. Tests confirm that these particles are essentially non-leaching. Other process effluents are purge water and clarifier underflow solids. The purge water may be treated by using available wastewater technology. The clarifier underflow material consists of smaller size particles with somewhat higher carbon levels. It is essentially the same material as the slag and can be disposed of with the slag or recycled to the slurry preparation section.

PAGE 10 OF 12



Tennessee Eastman Facility in Kingsport, Tennessee



Montebello Research Laboratories in Southern California

Licensing

The Texaco Gasification Process for Solid Carbonaceous Feedstocks is offered for license by Texaco Development Corporation, a wholly-owned Texaco Inc. subsidiary responsible for worldwide licensing of Texaco technologies. Texaco Development Corporation provides comprehensive assistance, on a fee basis, to clients interested in this process. These services include:

PAGE 11 OF 12

- Feed sample analysis
- Feasibility and design optimization studies
- Bench and pilot plant testing
- Process design packages
- Basic engineering
- Detailed engineering support
- Start-up assistance
- Operating training on process simulator
- Operating computer programs
- Continuing technical support and technology updates
- Ongoing technical exchange with operators and engineers of TGP plants
- Plant optimization and debottlenecking studies
- Vendor assistance

Many years of successful operating experience continue to advance the state-of-the-art Texaco Gasification Process. It is a highly economical and efficient tool for converting all types of feedstocks to a synthesis gas (hydrogen and carbon monoxide) which can be used for power generation or for the manufacture of a wide variety of products.

For further information, please contact:

Texaco Development Corporation
2000 Westchester Avenue
White Plains, NY 10650
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Telephone: (914) 253-4079

Telex: 1791144

Fax: (914) 253-7744

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DOCUMENT NO. 16
PAGE 1 OF 18

DOCUMENT NO. 16

TEXACO COAL GASIFICATION BROCHURE

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PAGE 1 OF 18

DOCUMENT NO. 16

TEXACO COAL GASIFICATION BROCHURE

QUESTIONS AND ANSWERS ABOUT TEXACO COAL GASIFICATION

- Q - Has a Texaco Coal Gasification plant produced electric power on a commercial scale?**
- A - Yes.** Since May 1984, the Cool Water Plant in California's Mojave Desert has been converting 1,000 tons of coal per day to 120 megawatts of electricity. Future plants will use gasification modules of approximately the same size.
- Q - Isn't this type of facility too much like a chemical plant for utility personnel to operate?**
- A - No.** Since startup, Cool Water has been operated successfully by utility personnel.
- Q - Okay, but isn't a gasification plant expensive to build and operate?**
- A - Capital costs are very competitive with other types of coal-based power plants.** What makes coal gasification plants especially attractive is that operating and maintenance costs are approximately 10 percent lower.
- Q - Is coal gasification suitable to other applications?**
- A - Yes.** A Texaco gasification plant can be designed to produce commercial quantities of steam, hydrogen, and methanol, as well as other products.
- Q - Is gasification really commercially proven?**
- A - Yes it is.** The first plant was licensed over 30 years ago, and over 90 Texaco gasification plants have operated worldwide.
- Q - Aren't there other coal gasification technologies?**
- A - Yes,** but none have amassed the commercial operating experience of the Texaco process.
- Q - Conventional coal burning plants have environmental problems. Is this true of the Texaco process?**
- A - No.** In fact, it uses coal more cleanly than any other commercially available technology. The Cool Water Plant has been the world's cleanest coal-based power facility.
- Q - Doesn't a Texaco gasification plant consume more water than a conventional coal plant?**
- A - You might think so,** but the process actually consumes less water than other coal burning technologies. Water recycling and reuse are incorporated in the design.
- Q - Is Texaco prepared to offer assistance to coal gasification clients?**
- A - Providing quality service is a priority.** The company is ready to help in all phases of your gasification program with a full range of services from planning through operations. Highly experienced people are available to work with you at every step.

Electricity is the cornerstone of modern life but traditional methods of generating it—using coal, oil, natural gas, and nuclear—often threaten the environment, are scarce, or are not economic. Clearly, there was a need for a new way, a better way.

Texaco has now bridged the technology gap by perfecting The Texaco Coal Gasification Process. This is a method of using coal—the world's most abundant energy resource—to generate electricity cleanly, efficiently and economically. When linked to a combined cycle turbine system, Texaco coal gasification is the best way to generate electricity today and in the future.

Here are some of the reasons why Texaco coal gasification is gaining widespread acceptance and recognition for electric power generation:

Performance • Texaco gasification works. Commercial Texaco gasification plants using solid, liquid and gaseous fuels have operated for years at some 90 locations around the world, reliably producing synthesis gas for chemical feedstocks and electricity.

Fuel • Coal guarantees an adequate and secure supply of fuel throughout the plant's life.

Environment • There's just no cleaner method of using coal. Texaco coal gasification sets new standards for air, water and solid waste emissions.

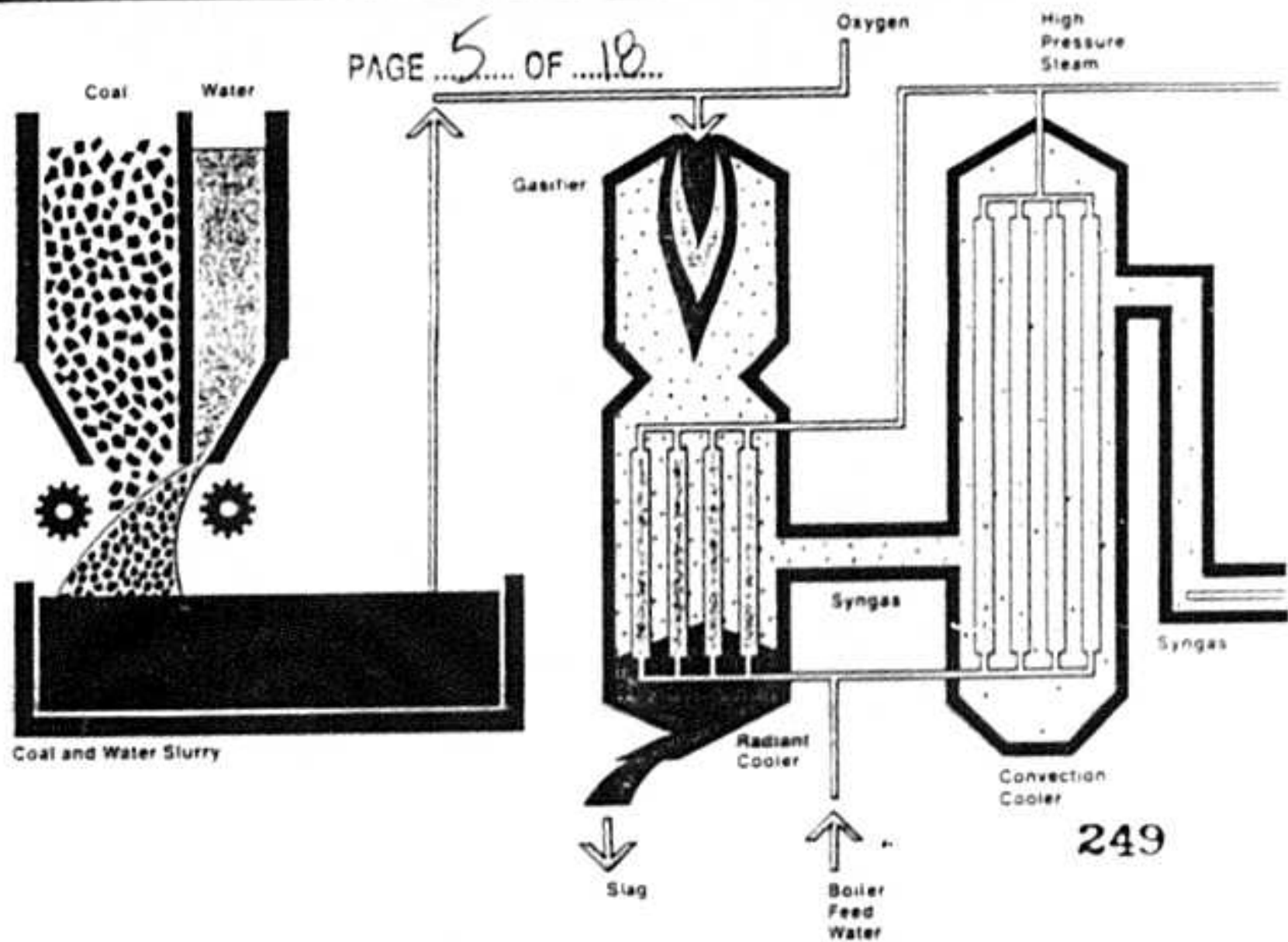
Efficiency • Texaco gasification is an efficient alternative for conversion of coal to clean electrical energy.

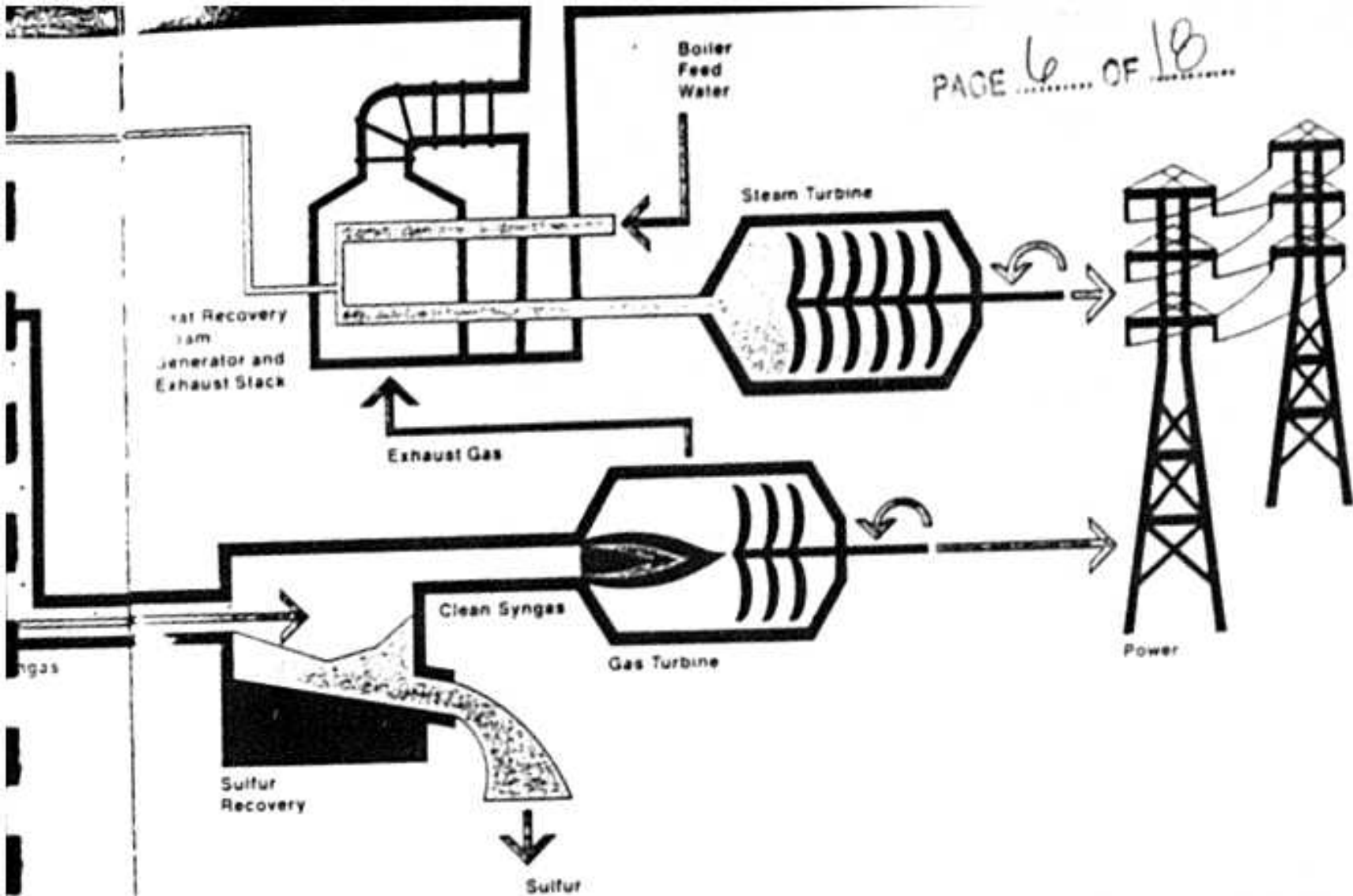
Economics • The many advantages of Texaco gasification are even more attractive when combined with a price tag that's competitive with other power generation systems.

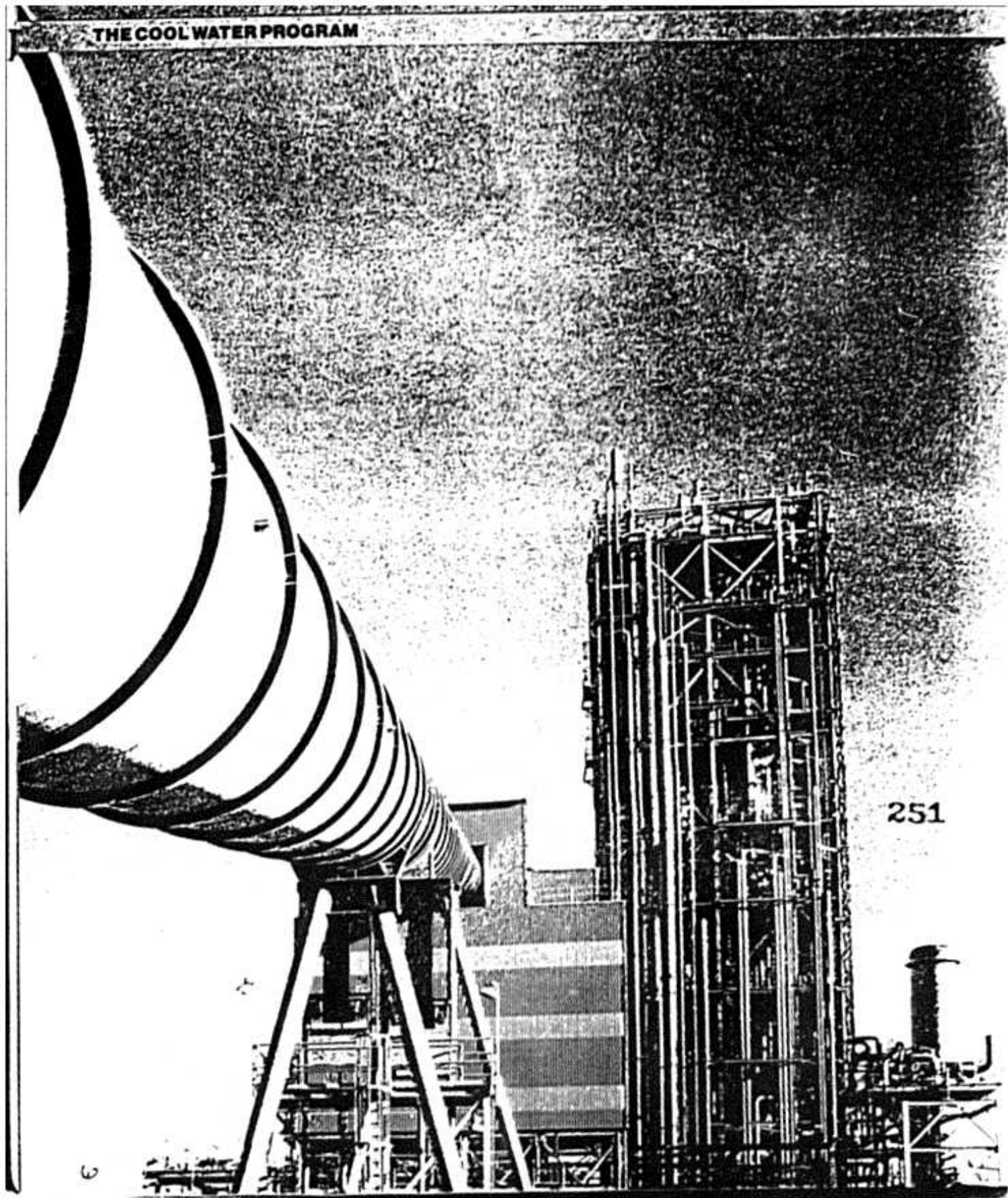
• **Texaco Coal Gasification**

• **Tomorrow's Technology**

• **Commercially Proven and Available Today**







251

The Cool Water Program and the Texaco process have been the recipients of awards from American Society of Mechanical

Engineers, Institute for the Advancement of Engineering, Chemical Engineering Magazine, and Power Magazine.

PAGE 8 OF 19

The Cool Water Coal Gasification plant, located in the Mojave Desert, midway between Los Angeles and Las Vegas, has been demonstrating that integrating gasification with a combined cycle power block works on a commercial scale.

Since startup in May 1984, plant performance has been outstanding. Cool Water has been converting 1 000 tons of coal per day to a medium BTU syngas to produce 120 megawatts of electricity. That's enough power to fill the needs of 100,000 homes.

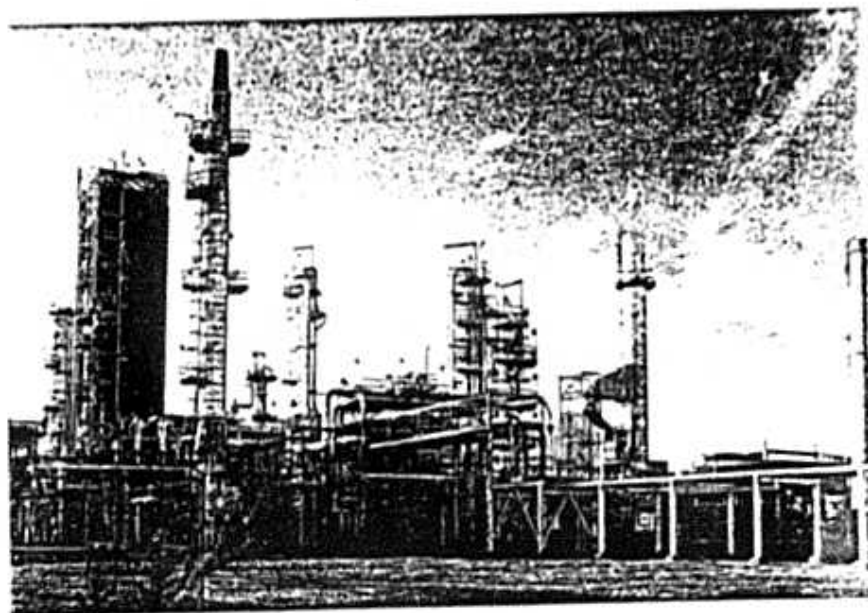
Environmentally, the plant has exceeded expectations. Cool Water is designed to gasify coals with a wide range of sulfur contents. Several types of coal have been run to fully test the process, including a Western coal (SUFCO) with 0.4 percent weight sulfur; Pittsburgh Number 8, an Eastern coal with a 2.9 percent weight sulfur; and Illinois Number 6, a mid-western variety with a 3.0 percent sulfur content. With all three of these coals the process performed remarkably, generating design levels of electricity and removing at least 97 percent of the sulfur.

Cool Water was funded privately by six participants: Texaco Inc., Southern California Edison, The Electric Power Research Institute, Bechtel Power Corp., General Electric and a group of Japanese companies known collectively as the Japan Cool Water Program Partnership (JCWP).

In addition, the Empire State Electric Energy Research Corp. and Sohio Alternate Energy Development Company are contributors to the program. Cool Water was the recipient of the first Synthetic Fuels Corporation award for assistance in the demonstration of this technology.

Cool Water confirms that the Texaco based IGCC process is reliable and is economically competitive with conventional coal-fired plants with scrubbers.

Forward-looking utilities planning new facilities are looking to the Cool Water project as their working model for growth.



▲ Above, syngas after leaving the gasifier is cleaned of particulates and sulfur in the gas cleaning section, then sent to a combined cycle turbine system.

◀ At left, coal is fed to a wet grinding system then the slurry is pumped to the gasifier tower.

9 Feb 1988

Texaco's 30 years of experience in gasification have enhanced the operation of today's facilities. The experience being gained by

today's commercial units is being incorporated into designs and operating procedures for future plants.

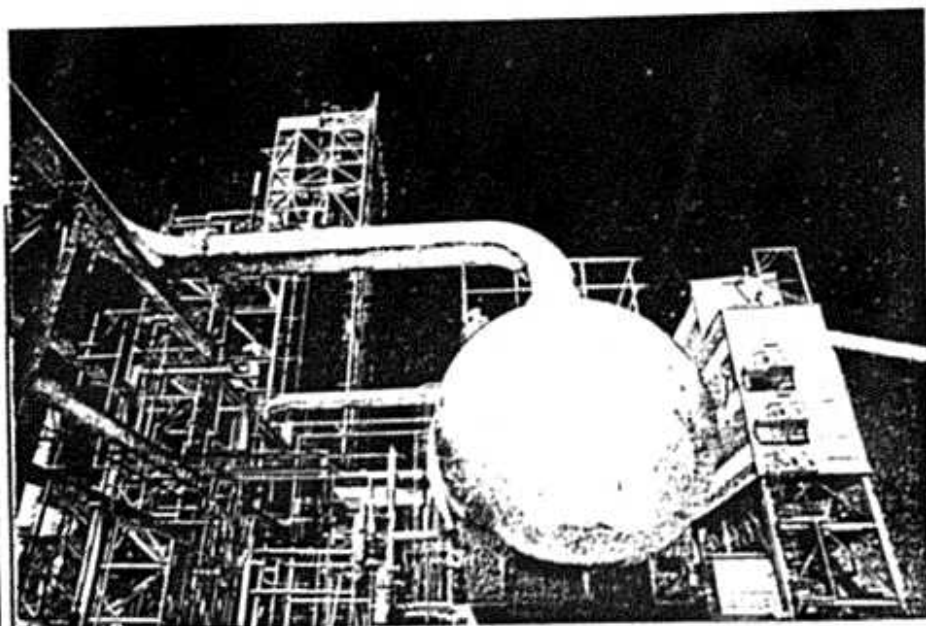
OPERATING FEATURES

The Texaco Coal Gasification Process is easy to operate, it is reliable, and it has competitive operating costs.

The features detailed below apply to the electric utility industry, but are equally valid for other uses:

- **Heat Rate** A Texaco-based coal gasification plant can be designed to operate at a heat rate of 8,900 BTU per kilowatt hour or lower. This represents a solid 10 percent improvement in efficiency over conventional coal plants.
- **Availability** Experience with commercial coal gasification plants has shown that a Texaco Integrated Gasification Combined Cycle plant has a projected full-load availability of at least 85 percent. This increases to 93 percent with the use of a backup fuel for the combined cycle system.

- **Turndown** Power plants must be able to adjust their output to meet variations in load demand. A Texaco gasification plant responds to these changes with only minor performance penalties. A turndown to 60 percent of gas production trims gasification efficiency by approximately one-half of one percent. Cutting production to 25 percent of capacity means an efficiency cut of less than four percent.
- **Load Following** Cool Water has successfully demonstrated the ability to respond rapidly to load changes. To meet a 20 percent load change, for example, the plant has adjusted its output at a rate of greater than four percent per minute. During load change, gas production is determined by demand from the gas turbine, and the total plant output is set by the plant load-control circuit. Appropriate control features are incorporated in the design, enabling a plant to easily satisfy the load changing requirements of most utilities.
- **Ease of Operation** Properly trained plant personnel routinely handle operations at commercial-scale Texaco coal gasification plants producing ammonia, chemicals and electricity. Cool Water, with its integration of gasification and combined cycle technology, is run very successfully by utility personnel.
- **Operating Costs** Actual Cool Water operating data, adjusted for plant size (to 375MW) and heat rate differences (to 8,900 BTU KWH), show operating costs of approximately 2.5 cents per kilowatt hour. Considering that operating costs for comparable new conventional coal plants are typically estimated to be at least 10 percent higher, this means substantial savings for utilities.



Phased construction of an IGCC plant offers several advantages. One of the most prominent is the

ability to use natural gas or fuel oil in the short term, but retain the long term security of a coal based system.

CONSTRUCTION AND CAPITAL COSTS

Having the flexibility to add generating capacity in increments, as needed to match power demand (phased construction), reduces economic risk to utility companies and frees capital for other uses. Texaco gasification plants can grow in stages, enabling the utility to:

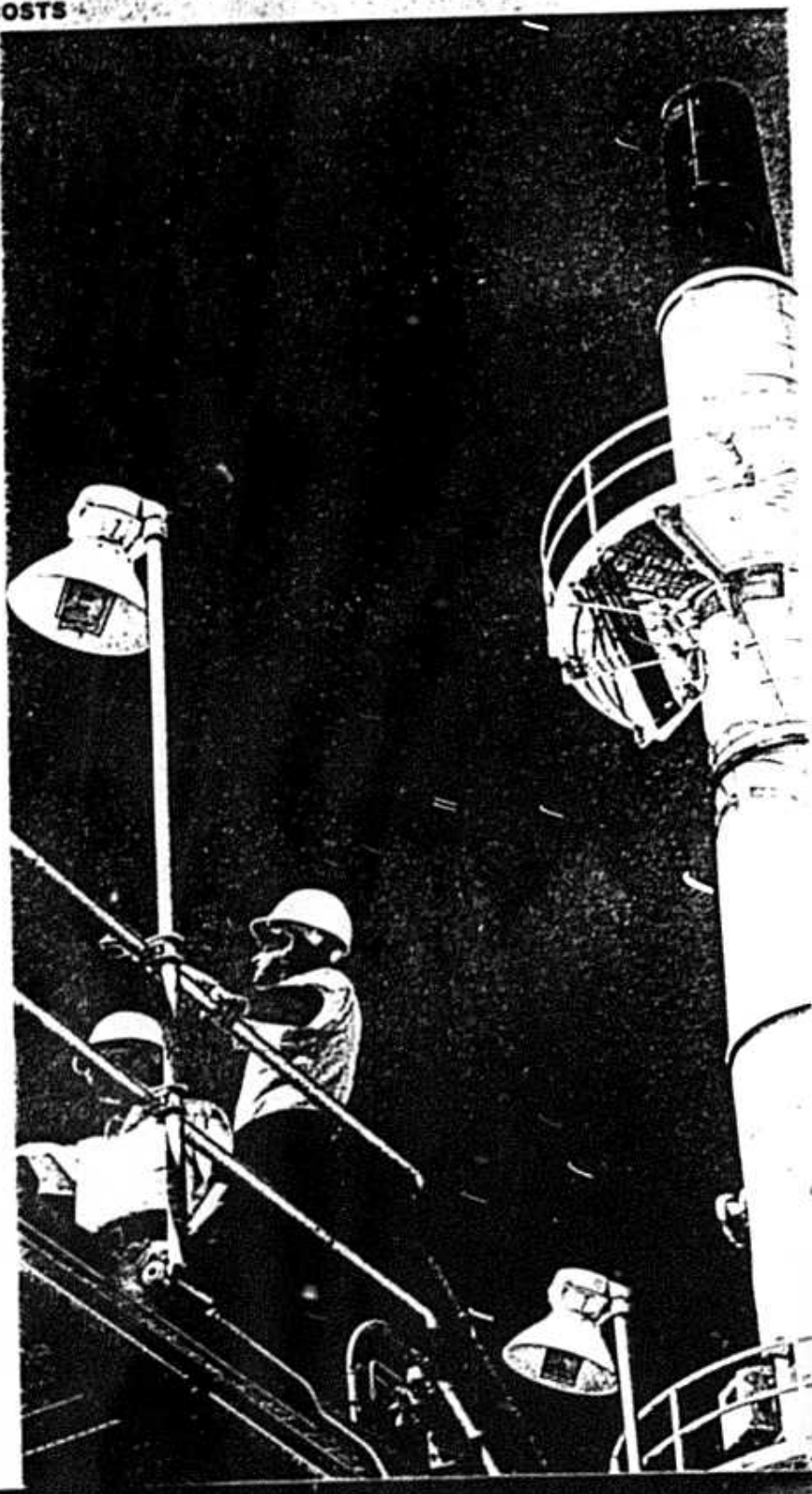
- Increase planning flexibility
- Build in small, efficient increments to match load growth
- Operate initially on liquid or gaseous fuels
- Reduce carrying charges during plant construction
- Reduce dollar commitment risk
- Achieve earlier return on investment

Unlike conventional pulverized coal units, the IGCC's modular construction and operation take advantage of phased construction and allow gradual and cost-effective expansion of power capacity. Combustion turbines for peaking service can be added in stages.

In addition, a combined-cycle facility can be added for intermediate service and then be used as a base-load plant with gasification when fuel prices, availability and/or load demand dictate.

Remember, an IGCC plant can be built for a price comparable to a conventional, coal-fired plant with desulfurization scrubbing units. The capital cost of a 400 MW IGCC plant, excluding an oxygen plant, is about \$1,100 per kilowatt. Oxygen can either be purchased from a third party or can be supplied from a plant owned by the power facility. The capital cost of the oxygen plant is about \$200 per KW.

There's no question that, when coupled with attractive heat rates, lower operating costs and phased construction, the overall capital and operating costs of the Texaco system are very competitive.







Texaco gasification is the world's cleanest commercially proven method of using coal for electric power production. The environ-

mental results from Cool Water have been far superior to stringent EPA standards for coal based power plants.

ENVIRONMENTAL

PAGE 13 OF 18

The Texaco Coal Gasification Process uses coal more cleanly than any other commercially available technology. It sets new standards for airborne emissions, water usage and waste utilization. Cool Water is the world's cleanest coal-based power plant.

Air

Airborne emissions of sulfur dioxide, nitrous oxides and particulate matter are well within the current New Source Performance Standards (NSPS) set by the Environmental Protection Agency (EPA).

The chart at left compares the actual emissions levels at Cool Water (Orange Bars) with the EPA's NSPS standards (Blue Bars). While most commercial methods of producing electricity from coal struggle to meet Federal standards, Cool Water's levels easily surpass them.

Gasification (partial oxidation) turns the sulfur in coal into hydrogen sulfide (H_2S). The hydrogen sulfide is removed using commercially proven technology which reduces the sulfur level in the gas by more than 97 percent. The result at Cool Water is essentially a pure elemental sulfur—a yellow powder widely used in agriculture, rubber and chemicals manufacture.

Water

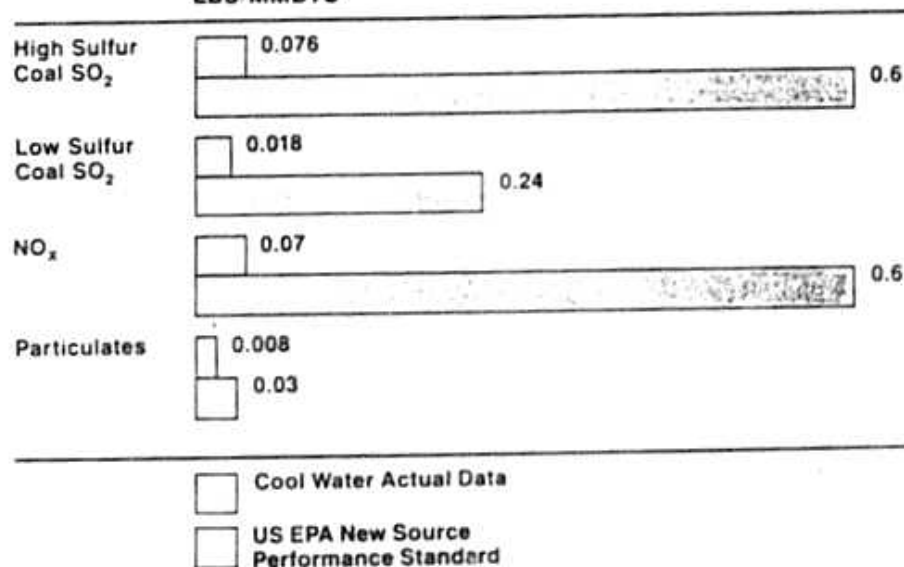
An IGCC system uses about a third less water than a comparably sized conventional coal plant. Like conventional steam-based power plants, IGCC plants lose most of their water through evaporation in cooling towers. However, since IGCC technology uses a gas-fired combustion turbine, which requires no steam for over half its electric power output, total water loss is much less than with conventional steam-based plants.

The slurry feed system that delivers coal to the gasifier consumes considerably less water than might be expected. A typical slurry system mixes two pounds of coal with each pound of water. That's not much volume compared to the plant's total water use. And because the slurry water doesn't have to be very clean, recycled waste water from elsewhere in the plant can be reused in the slurry system.

Waste

Conventional coal-burning technology typically creates disposal problems for large volumes of solid waste. With the Texaco IGCC system, the solid wastes are mainly sulfur and a non-hazardous slag material which can be used in concrete and asphalt. You may not even think of the sulfur and slag as waste since they are safe, manageable and salable.

ENVIRONMENTAL PERFORMANCE
LBS/MMBTU



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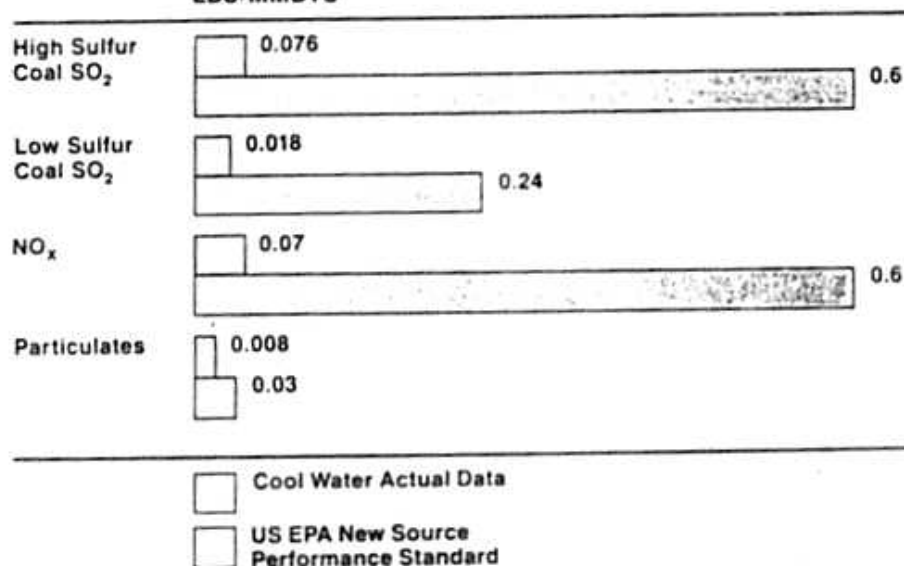
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ENVIRONMENTAL PERFORMANCE
LBS/MMBTU



Texaco's Montebello Research Laboratory has been the world's leading center for the development of coal gasification. Its

expertise is of great value to the successful operation of all current and future Texaco gasification facilities.

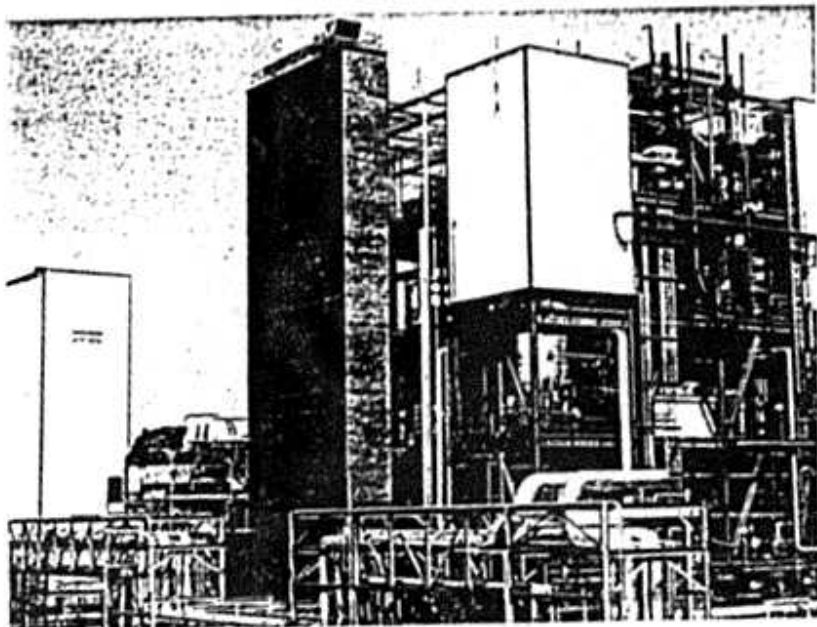
PROCESS IN USE

Cool Water is just one of four full-scale Texaco Coal Gasification plants in commercial operation today. Several more are on the drawing board.

Worldwide, over 90 plants have used Texaco gasification to make syn-gas from various petroleum feedstocks. Many of the key process components in these plants, such as sulfur removal and recovery equip-

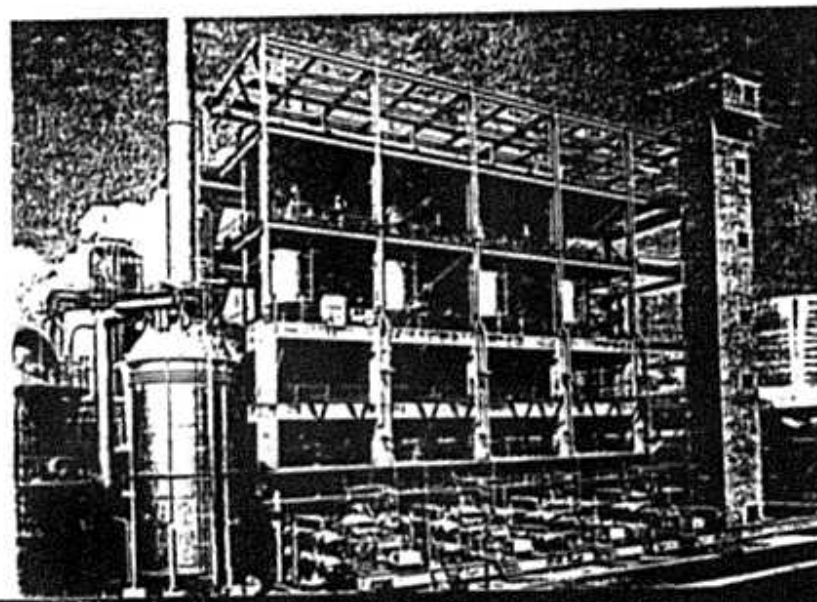
ment, are used routinely in oil refineries and other industries.

Through close involvement in these gasification projects and continuing exchange of technical information, Texaco has gained invaluable operating experience and has enhanced the process design for maximum efficiency. This expertise can now be put to work for you.



The Tennessee Eastman Facility in Kingsport, Tennessee.

The Ube Ammonia Plant in Ube City, Japan.



Coal gasification is a very versatile technology. It can be used for cogeneration and multi-product "energy park" projects.

Development and Demonstration

Texaco has traditionally been on the cutting edge of technology. The Texaco Coal Gasification Process was pioneered over 40 years ago and has been perfected by advanced research and development. The primary center for this work is Texaco's Montebello Research Laboratory in Montebello, California. Here, three gasifiers ranging in capacity from 15 to 25 tons per day (TPD), are used to make performance evaluations for specific coals and to demonstrate process improvements.

At the time the Texaco gasification process was developed, two demonstration plants were constructed. One, a 160 TPD facility completed by Ruhrchemie A.G. at Oberhausen, West Germany, produced syngas to make chemicals. It served as the design basis for a commercial 800 TPD plant, also located in Germany and completed in 1986. See below.

The second demonstration plant, a 200 TPD facility in Muscle Shoals, Alabama, was built by the Tennessee Valley Authority to produce syngas for ammonia manufacture.

These demonstration facilities helped provide the groundwork for today's commercial plants.

Tennessee Eastman

Tennessee Eastman, a subsidiary of Eastman Kodak, has operated a 900 TPD gasifier at Kingsport, Tennessee since 1983, producing methanol and acetic anhydride. The gasifiers at the facility are shown on the left (top). Its performance has been excellent with an onstream factor of greater than 90 percent.

Tennessee Eastman continues to use coal gasification for a very good reason—it regards it as the best available production method.

Ube Ammonia Industry Co., Inc.

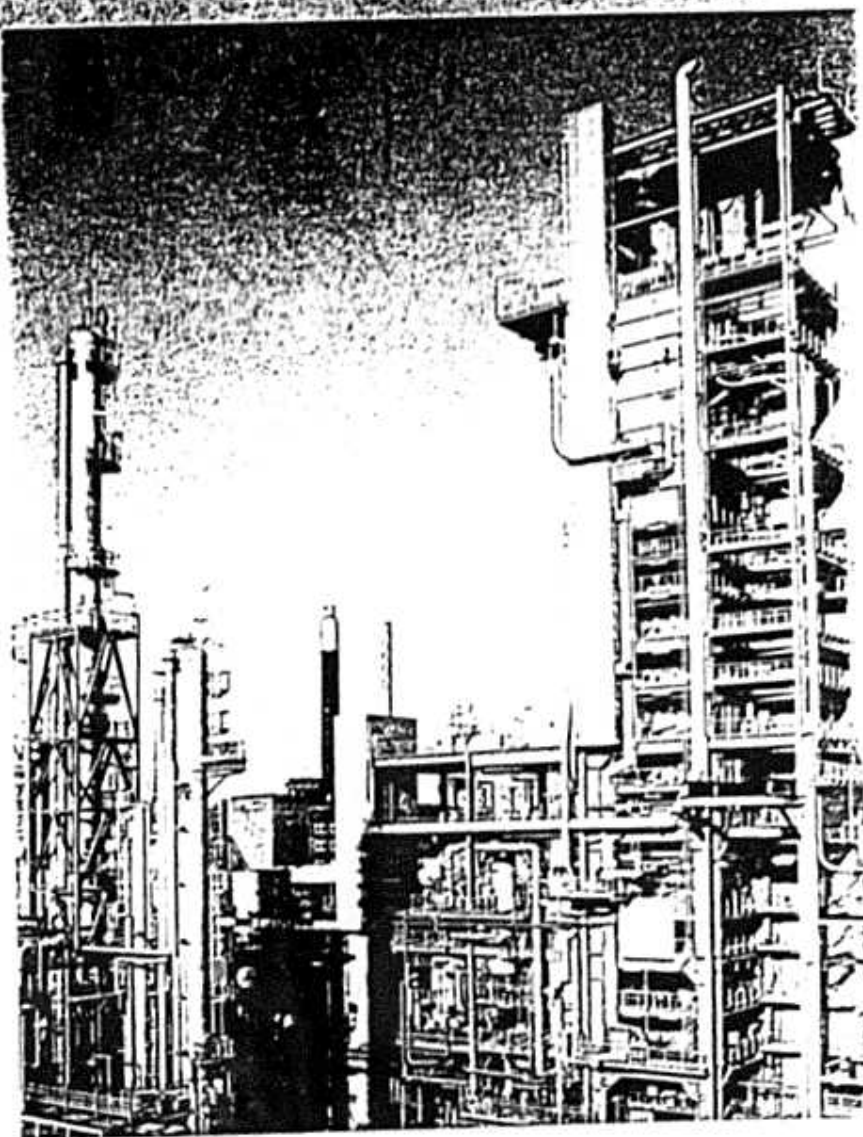
Ube owns and operates a 1,650 TPD Texaco gasification plant in Japan for ammonia production (left bottom). The facility began operations in 1984 and has been onstream over 90 percent of the time since startup. Ube has run on petroleum coke and has gasified a

variety of coals, including some from South Africa, Australia, and Canada.

Synthesegas Anlage Ruhr (SAR)

In the summer of 1986, an 800 TPD gasification plant began operations at the SAR plant in Oberhausen, West Germany. This plant is near the Ruhrchemie demonstration facility, which proved the soundness of gasification technology to SAR management. SAR produces syngas as a feedstock to make several organic chemicals.

▲ The Synthesegas Anlage Ruhr (SAR) plant in Oberhausen, West Germany.



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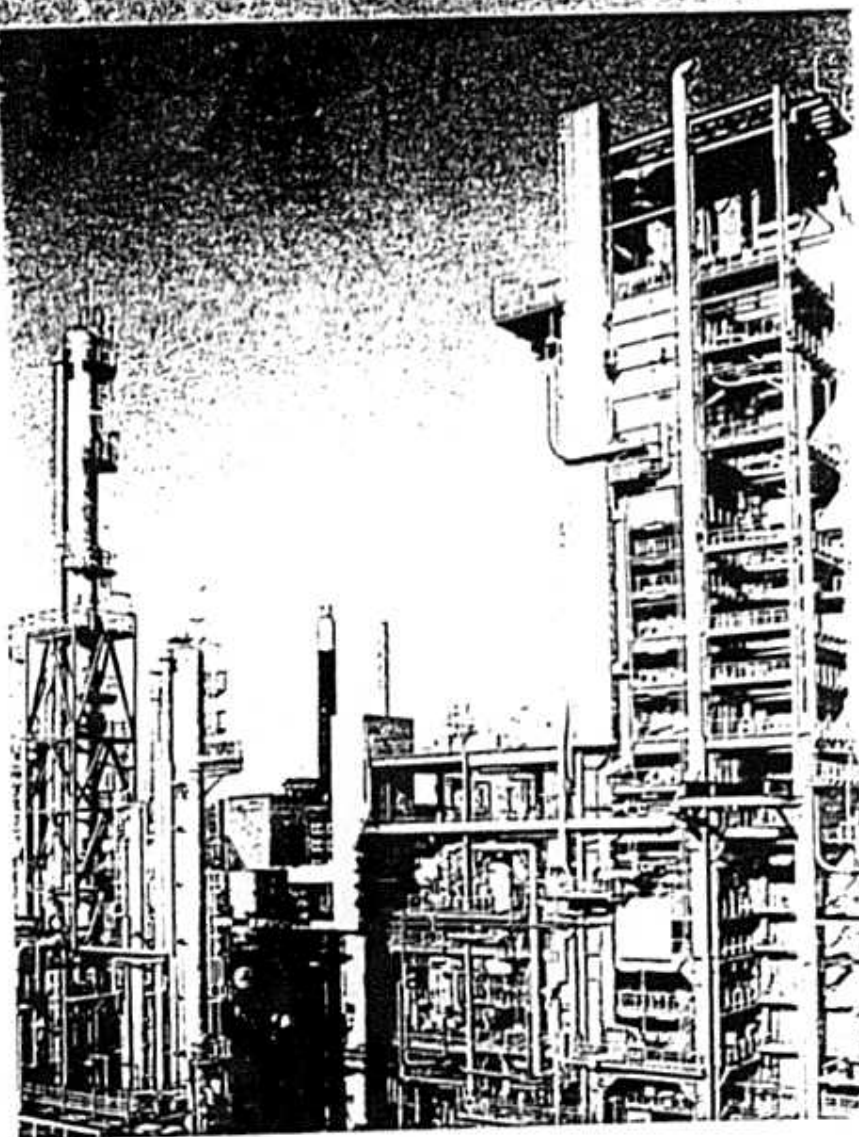
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Tennessee Eastman, a subsidiary of Eastman Kodak, has operated a 900 TPD gasifier at Kingsport, Tennessee since 1983, producing methanol and acetic anhydride. The gasifiers at the facility are shown on the left (top). Its performance has been excellent with an onstream factor of greater than 90 percent.

Tennessee Eastman continues to use coal gasification for a very good reason—it regards it as the best available production method.

Ube Ammonia Industry Co. Inc.

Ube owns and operates a 1,650 TPD Texaco gasification plant in Japan for ammonia production (left bottom). The facility began operations in 1984 and has been onstream over 90 percent of the time since startup. Ube has run on petroleum coke and has gasified a



variety of coals, including some from South Africa, Australia, and Canada.

Synthesegas Anlage Ruhr (SAR)

In the summer of 1986, an 800 TPD gasification plant began operations at the SAR plant in Oberhausen, West Germany. This plant is near the Ruhrchemie demonstration facility, which proved the soundness of gasification technology to SAR management. SAR produces syngas as a feedstock to make several organic chemicals.

▲The Synthesegas Anlage Ruhr (SAR) plant in Oberhausen, West Germany.

Either through licensing of the technology or joint ventures with Texaco, a variety of services are available:

- Coal Sample Analysis
- Coal Selection Studies
- Feasibility Studies
- Design and Environmental Test Runs
- Environmental Support for Licensing
- Process Design Package
- Project Management Support
- Construction Management Support
- Commissioning and Startup Support
- Operations and Maintenance Support
- Operator Training including Training Simulator
- Operating Computer Programs
- Continuing Technical Support and Technology Updates

261

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DOCUMENT NO. 17
PAGE 1 OF 18

DOCUMENT NO. 17

TEXACO PAPER OF OPERATING DATA

COOL WATER OPERATING RESULTS - IMPLICATIONS FOR NEW IGCC PLANTS

BY

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PRESENTED AT THE
SIXTH ANNUAL INTERNATIONAL PITTSBURGH COAL CONFERENCE

PITTSBURGH, PENNSYLVANIA
SEPTEMBER 25-29, 1989

D. H. WATTS, Texaco Syngas Inc., Apple Valley, CA

INTRODUCTION

It is with considerable pleasure that I address this gathering today to discuss the Cool Water Coal Gasification Program's (Program) achievements and to look at future applications of the Texaco Gasification Combined-Cycle (GCC) technology. To understand the current status of our gasification technology, we need to review the history and objectives which led to the creation of Cool Water. Then, I believe, we will have a better understanding of the significance of Cool Water's achievements.

Historically, Texaco began its gasification research in the late 1940's following World War II. Initial efforts involved making syngas from natural gas and oil. At that time, there was some question as to the amount of petroleum reserves and concern for our energy raw materials.

During this period, Texaco began to look at coal as a potential raw material for fuel and chemical manufacture. This led, in the 1950's, to the building of an air blown Texaco gasifier at the Bureau of Mines Center in Morgantown, West Virginia. This facility is now the Morgantown Energy Technology Center. Work on coal gasification stopped after the discovery of large oil reserves in the late 1950's. In the late 1960's, work began again on coal gasification technology. However, during the intervening years, a large number of plants were built based on gas, and oil gasification.

In the 1970's, we examined the energy situation and reviewed technology needs. We concluded that there was going to be a need for coal based technology and that gasification was a technology that could provide a variety of useful and different products. We also concluded that the Texaco Gasification Process (TGP) was an economical and environmentally superior process and that our vast commercial experience in gasification provided a sound basis upon which to move forward.

We further concluded that the generation of electric power using the clean fuel from gasification represented a potentially large market for the TGP. We asked ourselves what would it take to have confidence in a fully integrated gasification power plant to enable investors and utilities to build them. The conclusion was that a full sized commercial demonstration of a fully integrated plant would be required. The existing technologies were integrated and Cool Water was born.

Cool Water is the result of putting together a number of already commercial technologies including coal gasification, combined-cycle power generation, coal handling, and sulfur removal and recovery systems. The new key component of the demonstration was the integration of all these previously existing technologies. The Program's intent was to demonstrate that clean "syngas" could be produced that would be compatible with the demands of a gas turbine and meet the needs of an electric utility as it called for different power outputs. Also, that this could be done by processing a variety of coals. An integrated commercial demonstration would also provide the information necessary for financial investors to have confidence in a commercial plant.

PLANT EQUIPMENT AND PROCESS DESCRIPTION

The major equipment installed at the nominal 122 MW (gross) Cool Water facility includes a coal processing system; an oxygen plant; Texaco 1,200 TPD gasification units with both full heat recovery and quench designs; a sulfur removal and recovery unit; and, a combined-cycle power generation unit consisting of a General Electric Model MS7001E combustion turbine, Heat Recovery Steam Generator (HRSG) and steam turbine.

Figure 1 is an overview of the Cool Water plant. The plant includes all the commercial technologies of coal handling, grinding, oxygen production, power generation, gasification and sulfur removal, brought together in a fully integrated plant.

As indicated in Figure 2, the process begins when coal is wet ground in conventional grinding mills. The ground coal is slurried with water to solids concentrations between 60 to 75%. The coal slurry is safely and reliably pumped to the Texaco gasifier.

There the coal slurry is gasified by mixing it with oxidant in a specially designed burner. Unlike conventional coal combustion processes, the mixture is starved of oxygen and thus only partially oxidized.

By partially oxidizing the coal, mixtures of mostly hydrogen and carbon monoxide - H_2 and CO - are formed instead of carbon dioxide and water vapor - CO_2 and H_2O - that are formed in complete combustion. This predominantly CO and H_2 mixture is called synthesis gas, or more commonly, syngas. Normally, 98 to 99% of the feed coal carbon is converted to syngas.

Unlike conventional coal combustion processes, the Texaco partial oxidation reaction does not produce SO_x or NO_x , two important precursors of acid rain and smog. Instead, the reduced gases H_2S and N_2 are formed.

The gasification reaction also produces no tars, phenols or oils. The solid by-product from the reaction is called slag, a glassy material that has been certified non-hazardous, both by

Federal government standards and in environmentally-conscious California.

In power plant applications, the syngas proceeds to waste heat boilers, called syngas coolers, where high pressure steam is generated. The syngas is then scrubbed with water to remove particulates. The syngas proceeds to the sulfur removal and recovery section where gaseous sulfur components are converted to elemental sulfur, a valuable by-product. The purified syngas is water saturated and routed to a combustion turbine, producing electric power. Exhaust from the combustion turbine is used to superheat the syngas cooler steam which proceeds to a steam turbine where additional power is generated.

TEXACO GASIFICATION EXPERIENCE

The TGP is based on many years of commercial experience. Texaco has licensed over 95 gasification plants, four based on coal. Two coal gasification plants were designed with maximum heat recovery systems and two in the quench mode. Texaco has two gasifiers running in refineries located in Los Angeles and Louisiana. This broad base of experience is what was brought to Cool Water and what Texaco brings today in commercial gasification plants.

Texaco has taken its coal gasification technology through a sequence of steps to minimize risk involved in scaling up as shown in Figure 3. From the days of research, to the unit at Morgantown, West Virginia; through our pilot units in operation in Montebello, California; through demonstration at Tennessee Valley Authority in Alabama, and at Ruhrkohle/Ruhrchemie in West Germany into today's commercial plants at the Ube Industries in Japan; Tennessee Eastman in Tennessee; SAR Unit in Germany; and Cool Water in California, give evidence that the Texaco system is built on a solid commercial base. Further, two units underway in China will add to Texaco's commercial experience.

Figure 4 shows the history and size of the various operating plants using the Texaco Coal Gasification Process. The plants range in size from the 25 TPD pilot units at Montebello to the 1,650 TPD plant at Ube Industries in Japan.

COOL WATER ACCOMPLISHMENTS

Operating Performance

Cool Water gasified over 1.1 million tons of coal from four different feedstocks and produced over 2.7 billion KWH of electric power as indicated in Figure 5. The capacity factor, which is a measure of total plant availability, was about 70% in 1987 and 1988 and 59% overall during the demonstration period. The on-stream factor, which is a measure of gasification plant availability, was 76% in 1988 and 67% overall.

On the surface, these availability numbers appear comparable to conventional power generation technologies. Looking closer, they are actually rather impressive. Cool Water was built as a commercial-scale demonstration plant and was not designed to maximize plant availability.

The plant was designed for single train operation with minimal sparing and did not include backup fuel capability. The test and demonstration nature of Cool Water introduced intentional availability penalties while testing alternate coals, conducting load following tests, demonstrating alternate operating and gasification modes, and performing elaborate environmental monitoring and testing activities in a first-of-a-kind plant.

The addition of multiple trains, sparing and backup fuel capability and the elimination of test and demonstration activities associated with a first-of-a-kind plant will substantially improve availability factors. Availability factors of 85% or higher, depending upon design considerations, are realistic for fully commercial GCC plants.

This data represents only a summary of the operating achievements at Cool Water. All of the individual achievements involving the integration of the technologies, and the individual reliability and operability of all components, are vital to having proven the commercial viability of the technology.

Economics

One of the basic objectives of Cool Water was to develop an economic data base from actual plant operating costs. These actual costs could then be adjusted and used to predict costs for future plants. Texaco initiated a major engineering study in November, 1988, after the selection of a prime contractor, in order to develop optimum integrated gasification plant designs. A number of gasification configurations for the utility industry as well as industrial cogeneration and polygeneration applications were reviewed. The studies indicated that commercial plants can be constructed at capital costs between \$1,450-1,550/KW, obtain levelized COE (mills/KWH) of 48.0-49.3 and achieve attractive dispatch costs less than 19 mills/KWH. The study scope was limited to consideration of technologies which are commercially available today and did not include potential gasification technology enhancements such as hot gas cleanup systems and gasifier in situ sulfur removal which offer the potential for further enhancing Texaco's technology in the future.

Alternate Gasification Modes

At Cool Water, Texaco demonstrated both maximum heat recovery and quench (non-heat recovery) gasification designs. The successful demonstration of both modes will allow utilities design alternatives in producing low cost electric power.

If the gasification system were designed for maximum heat recovery, a radiant/convective syngas cooler configuration would be selected. Plant heat rates of 8,900 Btu/KWH or lower can be achieved at capital costs approximately \$1,540/KW. If cost is of primary concern, the gasification section should be designed based on a quench system with no syngas coolers. The capital cost for such a plant would be \$1,450/KW with a net heat rate of 9,400 Btu/KWH. Perhaps the best compromise between maximum heat recovery and low capital cost configurations is a radiant only syngas cooler configuration. The capital cost for a radiant only configuration would be \$1,510/KW with a net heat rate of 9,100 Btu/KWH.

Load Change Capabilities

Dynamic load following tests have been demonstrated at Cool Water. Power output load changes of 50% at a ramp rate of greater than 5% per minute have been achieved. Dynamic load testing has been conducted demonstrating two modes. In the turbine lead mode, the turbine power output is selected and the plant control system automatically adjusts syngas production in the gasification plant by changing slurry and oxygen flow rates. In the gasification lead mode, the syngas production is adjusted and the combined-cycle unit power production is dependent upon the amount of syngas and steam available.

The gasification plant experiences a small turn-down penalty while the overall plant turn-down penalty is typical of that experienced by combined-cycle plants fueled with oil or natural gas. For example, a 70% turn-down in the gasification plant results in a less than 1% loss in gasification efficiency.

Texaco recognizes utility interest in operating power plants in both base load and intermediate duty. GCC technology provides the flexibility to turn down power production during off-peak periods with acceptable performance penalties. GCC technology also provides additional options not possible with conventional technologies. For example, the power plant can be ramped down while continuing to base load the gasification plant. The excess syngas not used for power generation can be converted into valuable products such as methanol. Methanol can be stored and utilized in stationary sources or used as a transportation fuel.

Operating Personnel Qualifications

Before the successful demonstration at Cool Water, there was concern about the level of expertise required to operate GCC plants. A common misconception was that the technology was complicated and would require highly trained engineering and technical personnel to operate. Cool Water proved that utility personnel with conventional power industry experience can be trained to operate GCC plants. Cool Water used Southern California Edison plant operators transferred from conventional

power plants. These plants included nuclear, oil, gas and coal units.

The operators were not hand selected and had the same general education level and experience as operators in conventional plants. The training program was similar to that used to train operators transferring between conventional plants. Plant owners will not require specialized expertise to staff and operate GCC plants. Normal labor pools, hiring practices and basic training programs can be used.

Alternate Coal Flexibility

Four alternate coals were successfully gasified. These include Utah (SUFCO), Illinois No. 6, Pittsburgh No. 8 and Australian (Lemington) coals. The coal qualities and plant performance characteristics are shown in Figure 6. The predominate coal gasified was the Utah (SUFCO) coal because it was the lowest priced coal on a delivered basis.

The ability to gasify a wide range of coals is important. It allows utilities to select the most economic feedstocks based on price and availability without operating penalties. Other flexibility features include on-line switching between different coal feedstocks, and the ability to blend coal with waste streams such as sewage sludge for potential waste-to-energy applications.

Safety Performance

For a first-of-a-kind plant, Cool Water achieved an excellent safety record. During the five-year demonstration, the plant recorded periods of 745 and 1,017 days without a lost time accident. Normal OSHA safeguards were used, and gas monitoring systems for CO and H₂S gases were implemented. Standard utility industry safety training programs and safety procedures were used, with minor site-specific modifications.

It is important to know that GCC technology can be safely operated, has proven safety systems built into the technology, conforms to familiar safety standards and incorporates existing safety training programs.

ENVIRONMENTAL PERFORMANCE

Cool Water demonstrated atmospheric emissions of SO₂, NO_x and particulates at levels 80 to 90% below Federal EPA New Source Performance Standards (NSPS), produced non-hazardous solid by-products (instead of wastes), produced easily treatable wastewater streams and incorporated water conservation process designs. Cool Water has been called the world's cleanest coal-fired power plant.

The atmospheric emissions for alternate coals tested at Cool Water are indicated in Figure 7. Coals with sulfur contents

between 0.4% and 3.1% were tested. The sulfur removal process can be designed to handle high sulfur content coals without appreciably affecting sulfur removal efficiency. Sulfur removal rates of 96 to 98% were achieved for the four alternate coals tested. This characteristic of GCC technology is important because it allows greater flexibility in selecting coal feedstock(s). Benefits could accrue from purchasing lower quality coals that are closer to the plant site, reducing both coal and transportation costs.

The solid by-products produced include high purity elemental sulfur and gasification slag. The by-products are classified as non-hazardous materials. There is no scrubber sludge or fly ash produced with GCC technology. The sulfur is sold and generates a revenue stream instead of a disposal concern. The gasification slag has been identified as a marketable material for use as a light weight aggregate and road base filler material. By-product utilization is an important consideration when evaluating alternative technologies and will become even more important as existing disposal sites close and new sites become more difficult to permit.

Wastewater streams have been thoroughly analyzed and the results show no harmful pollutants. Because of extensive recycling of process water, the wastewater streams are concentrated and are easily treatable in commercial wastewater treatment processes. Texaco demonstrated its proprietary wastewater treatment process in pilot plant operations at Cool Water.

The process water requirements for GCC plants are approximately one-third less than the requirements of conventional steam-based power plants, since more than half the power generated comes from the combustion turbine. The water requirements for the coal gasification process are approximately one-fifth of the total plant consumption. The cooling towers are the primary water consumer. The water conservation feature of GCC technology can be very important depending upon the availability and price of water resources.

As a result of the superior environmental performance demonstrated at Cool Water, we believe the permitting process for future GCC plants can be streamlined. Much of the baseline data generated at Cool Water is available to assist in permitting commercial facilities.

NEW GASIFICATION PLANTS

Today, based on a wealth of experience, Texaco is prepared to design highly efficient, commercial gasification-based power plants. These plants will have heat rates of 8,900-9,400 Btu/KWH and overall plant efficiencies of up to 43.5% (LHV basis) in some current designs; other designs, stressing reduced capital costs, are projected to achieve overall efficiencies of about 40%. These plants will have unmatched environmental performance. We offer a

variety of services, based on client preferences, feasibility studies and complete packages that include design, construction and operations.

Recent development efforts by Texaco have focused on the gasification of certain waste products that would be fed to the gasifier in conjunction with coal or petroleum coke. These include municipal sludges, refinery and chemical plant organic wastes and other waste streams. These types of waste streams are easily disposed of in the gasification process and provide, in most cases, a revenue stream improving overall project economics.

RESOURCES FOR FUTURE PLANTS

During Cool Water's successful operating history, valuable operating data and experience was acquired.

Cool Water implemented a Data Acquisition System (DAS) that monitored and electronically stored information from over 1,000 monitoring points located throughout the plant. This information has allowed accurate analysis and design modifications improving overall plant availability and efficiency. An extensive video, photo and engineering drawing library of all major vessels and equipment at Cool Water has been assembled. A complete collection of Cool Water reports, documents and technical papers has been compiled.

A computer-based simulator has been developed which has the capability to replicate the operation of Cool Water. Present plans are to modify the simulator to model fully commercial multi-train plants.

A test program utilizing metallurgical coupons in major vessels has provided valuable information regarding proper materials selection for future GCC plants.

Texaco has a skilled operating team with experience developed at Cool Water and other Texaco gasification plants throughout the world. This team is available to train operators and assist in plant startups and operations.

Comprehensive operating and safety procedure manuals, vendor lists and equipment specifications have been developed by Texaco based on actual operating experiences at Cool Water and other Texaco gasification facilities.

In construction we have insured that the components can be shop fabricated and shipped to the site instead of requiring on-site fabrication. Our history, including Cool Water, allows us to use our developed inspection criteria. Vessel sizing, erection and plant layout, are areas in which we excel. Indeed our Engineering Department has pioneered plant construction involving the lay-down and prefabrication of components prior to assembly

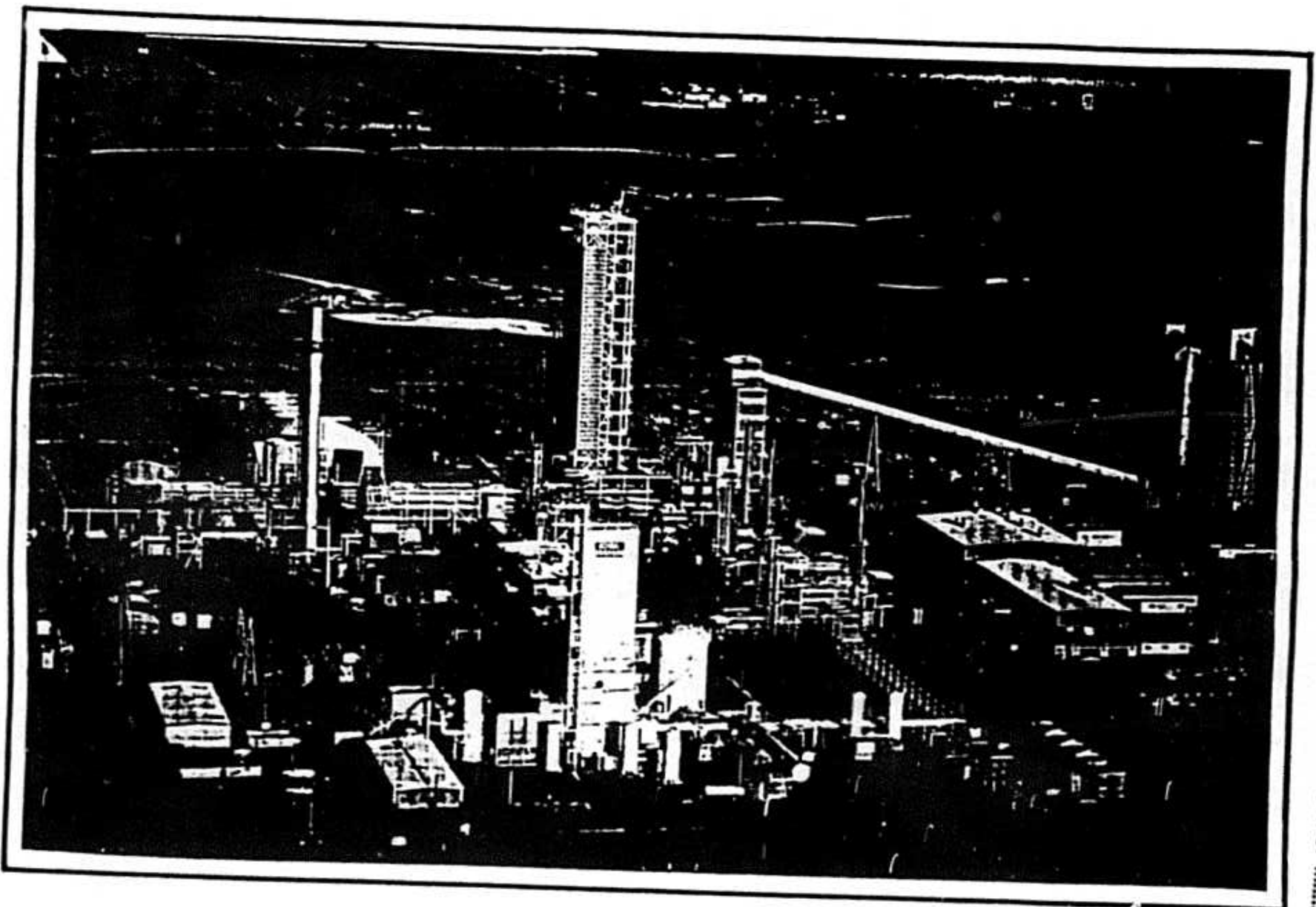
on a construction site. This enables us to minimize construction time and cut costs.

This collection of information, training aids and experience will be available for the design, engineering and construction of Texaco based GCC plants.

CONCLUSION

The Cool Water Program has just completed its highly successful five-year demonstration, provided the final information, know-how and confidence necessary to build commercial Texaco GCC plants and met or exceeded all its objectives.

Texaco is committed to bringing this technology to the market place, with commercial guarantees and long-term customer support. Our intent is to work with the utility and chemical industries to meet their needs for a reliable, cost competitive and environmentally superior technology option.



Texaco Coal Gasification Process History

MORGANTOWN
WEST VIRGINIA



RESEARCH

MONTEBELLO
CALIFORNIA



DEVELOPMENT

TVA
RUHRKOHLE-
RUHRCHEMIE



DEMONSTRATION

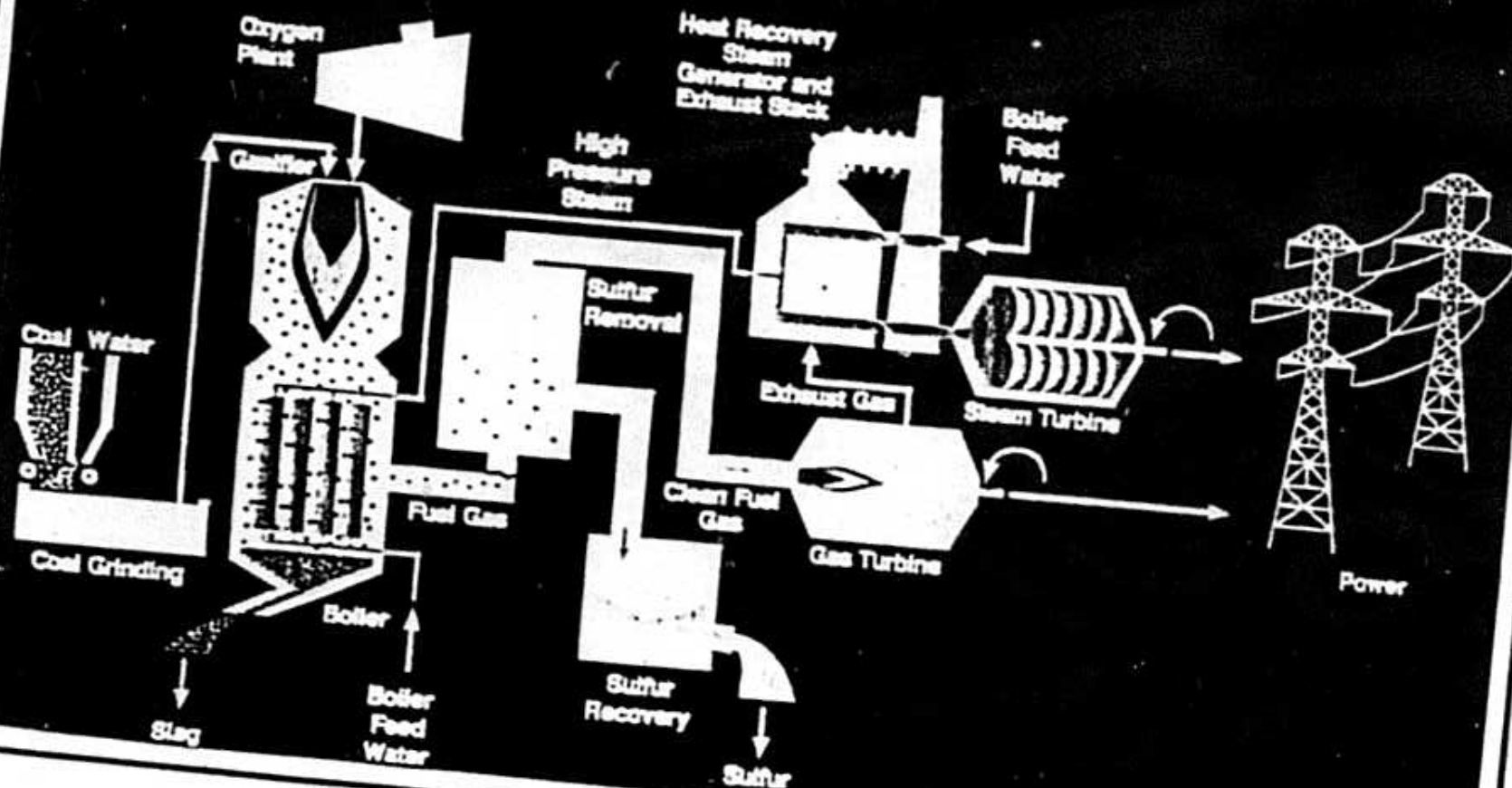
UBE
TENNESSEE EASTMAN
SAR
COOL WATER



COM



INTEGRATED GASIFICATION COMBINED CYCLE



COOL. WATER PRODUCTION SUMMARY

GASIFIER OPERATIONS (HRS.)	1,992	6,648	26,715
COAL GASIFIED (TONS, DRY)	88,767	298,270	1,116,701
GROSS ELECTRICITY FROM SYNGAS (MWH)	205,802	731,260	2,734,717
ONSTREAM FACTOR	87.0%	75.7%	67.4%
CAPACITY FACTOR	76.4%	69.6%	58.7%

	SIZE TPD COAL	START-UP DATE
MONTEBELLO	25	1973
RUHRKOHLE/RÜHRCHEMIE	165	1978
TENNESSEE VALLEY AUTHORITY	200	1982
TENNESSEE EASTMAN	900	1983
UBE	1,650	1984
COOL WATER	1,000	1984
SAR	770	1986
LUNAN	400	1989
SHOU GANG	1000	1990



**PLANT PERFORMANCE/
ALTERNATE FEEDSTOCKS
(AT 1000 TPD THROUGHPUT)**

	<u>SUFCO</u>	<u>ILL. NO. 6</u>	<u>-PITTS. NO. 8</u>	<u>LEMINGTON</u>
HEATING VALUE (Btu/lb) HHV	12,360	12,970	14,100	12,730
SULFUR (%)	0.4	3.1	2.9	0.45
ASH CONTENT (%)	8.8	11.3	7.4	13.4
ASH FUSION TEMP (°F)	2200	2250	2425	2700+
GROSS POWER PROD. (MW)	116	120	129	119
OVERALL HEAT RATE (Btu/kwh)	10,950	11,700	11,460	10,740

Environmental Performance

LBS/MMBTU

HIGH SULFUR
COAL SO₂

0.076

0.6

LOW SULFUR
COAL SO₂

0.018

0.24

NO_x

0.07

0.6

PARTICULATES

0.008

0.03

COOL WATER ACTUAL DATA

US EPA NEW SOURCE
PERFORMANCE STANDARD

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DOCUMENT NO. 18
PAGE 1 OF 19

DOCUMENT NO. 18



TEXACO
GASIFICATION

GASIFICATION OF SEWAGE SLUDGES

RICHARD B. ZANG, PE

AND M. RASHID KHAN, PhD

TEXACO INC.

AERD

For presentation January 15, 1991 to the
New York Water Pollution Control Association



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PAGE 3 OF 19

GASIFICATION OF SEWAGE SLUDGES

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TEXACO INC.

ALTERNATE ENERGY AND RESOURCES DEPARTMENT

INTRODUCTION

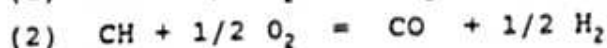
Waste Gasification is an extension of Texaco's conventional fuels gasification technology, in which carbonaceous materials are reacted with a limited amount of oxygen at high temperatures. The partial oxidation of hydrocarbons produces a gas composed primarily of carbon monoxide and hydrogen. The gas, called synthesis gas or syngas, is used both as a feedstock for the production of chemicals such as hydrogen, ammonia, and methanol, and as a clean-burning fuel for power generation. Texaco gasification technology has been used for forty years on feeds such as natural gas, liquid petroleum fractions, coal, and petroleum coke, and is currently licensed in 17 countries for the production of electric power, ammonia and other chemical products. Four commercial coal gasification facilities and 95 petroleum gasification plants have been built.

Sewage Sludge is one of the wastes that can easily be gasified to produce syngas and to ensure the destruction of harmful pollutants. This paper describes the development of the technology to include the disposal and beneficial use of municipal sewage sludge.

For presentation January 15, 1991 to the New York Water Pollution Control Association

PROCESS REACTIONS

The chemistry and thermodynamics of gasification are based on three types of gasification reactions. Equation (1) represents complete combustion of a hydrocarbon, represented by CH, where enough oxygen is supplied to convert all the carbon to carbon dioxide and all the hydrogen to water. The overall reaction is highly exothermic. Equation (2) shows the less exothermic partial oxidation with a limited amount of oxygen. Finally, equation (3) depicts the reaction with steam or water vapor to produce a mixture of hydrogen and carbon monoxide. This reaction is endothermic.



Most gasification processes use a combination of all three reactions in such a manner that external heat or energy does not have to be supplied to the gasifier.

The Texaco Coal Gasification Process (TCGP) yields a medium-Btu gas composed primarily of hydrogen, carbon monoxide, carbon dioxide, and hydrogen sulfide with small amounts of methane. The resulting syngas has a heating value ranging from 280-320 Btu/scf (10,400-11,900 kJ/m³) and can be as high as 500 Btu/scf (18,600 kJ/m³).

Medium-Btu gas is one of the most versatile fuels produced from coal. Many industrial facilities now burning oil or natural gas, and combined-cycle electric power plants and existing gas-based power stations can use this clean burning fuel.

TCGP PROCESS EQUIPMENT

The Texaco Coal Gasification Process uses an entrained bed gasifier with concurrent flow of oxygen and feed, and operates at pressures well above atmospheric, at 350 to 900 psi. It is operated at a temperature above the melting point of the ash in the feed stream, usually above 2400 deg F, which is referred to as operation in the slagging mode. At this temperature, undesirable hydrocarbon

byproducts associated with other gasification processes are not formed. When used to handle hazardous wastes, it is essential that no liquid hydrocarbon streams are formed which could contain residual hazardous materials, or be hazardous themselves.

The Texaco gasifier is a simple refractory-lined pressure vessel into which the feed, in slurry form, is injected at the top through a specially designed burner with a stream of high-purity oxygen. This mixture ignites on contact and reaches temperature of 2500°F in a very short time. The water in the feed slurry serves to moderate the process temperature and participates in the carbon, hydrogen and oxygen reactions. At these high temperatures all the organics are converted to carbon monoxide, hydrogen, carbon dioxide and small amounts of methane. The ash-forming components of the feeds are melted and fused together. Any sulfur is converted to hydrogen sulfide and small amounts of carbonyl sulfide. At the bottom of the gasifier the syngas and slag pass through a pool of water where it is cooled and the slag is solidified to a glassy, non-leaching material. The slag is withdrawn through a lockhopper at the bottom of the gasifier. There are no moving parts in the gasifier.

After leaving the gasifier the syngas passes through a water wash scrubber to remove entrained particulates and then through a cooling train to recover and recycle low grade heat. This system may include a water-gas shift unit to convert most of the carbon monoxide to hydrogen and carbon dioxide via a catalyzed reaction with water and to convert the carbonyl sulfide to hydrogen sulfide. This has several benefits - it enhances overall sulfur recovery levels in the subsequent gas cleanup train, it provides a high temperature source of heat for superheating various low pressure steam flows, and it loads the final syngas product with hydrogen. The combination of these two gases when used as fuel results in very low NOx emissions without the need for water or steam injection. The syngas can be further upgrade to high-purity hydrogen.

The cool syngas is then processed in a sulfur removal unit to extract the hydrogen sulfide and to convert it to elemental high-purity sulfur which is a saleable byproduct. Sulfur recovery levels in excess of 99.5% can be expected. Carbon dioxide can be extracted and liquified for sale to the industrial gas market.

COOL WATER COAL GASIFICATION PROGRAM DAGGETT, CALIFORNIA

A consortium of companies including Texaco completed construction of the Cool Water Coal Gasification Plant in 1984. This 1000 TPD plant is the first commercial, Integrated Coal-Gasification Combined-Cycle (IGCC) power plant in the world.

During its five-year demonstration period, sponsored by the Department of Energy, Cool Water proved that TCGP based IGCC plants could reliably, safely and cleanly produce power from coal. It gasified 1,116,701 tons of Utah, Illinois, Pittsburgh, and Australian coal.

In 26,715 hours of operation, much of it spent in rigorous test and demonstration periods, the plant produced 2,734,717 MW. This is more power generation than the amount produced by all competing gasification-based power plant processes combined.

Before the successful demonstration at Cool Water, there was concern that the technology was complicated and would require highly trained engineering and technical personnel. Cool Water proved that utility personnel with conventional power industry experience can be trained to operate IGCC plants. Cool Water used Southern California Edison plant operators transferred from conventional power plants.

Cool Water demonstrated atmospheric emissions of SO₂, NO_x and particulates at levels 80 to 90% below US EPA New Source Performance Standards, produced non-hazardous, solid byproducts (instead of wastes), produced easily treatable wastewater streams

and incorporated water conserving process designs. Cool Water has been called the world's cleanest coal-fired power plant.

The atmospheric emissions for alternate coals tested at Cool Water are indicated in Figure 1. Coals with sulfur contents between 0.4% and 3.1% were tested. The sulfur removal process can be designed to handle high sulfur content coals without appreciably affecting sulfur removal efficiency. Sulfur removal rates of 96 to 98% were achieved for the four alternate coals tested. This characteristic of IGCC technology is important because it allows greater flexibility in selecting coal feedstocks. Benefits could accrue from purchasing lower quality coals that are closer to the plant site, reducing both coal and transportation costs.

The solid by-products produced include high-purity elemental sulfur and gasification slag. The byproducts are classified as non-hazardous materials. There is no scrubber sludge or fly ash produced with IGCC technology. The sulfur is sold and generates a revenue stream instead of a disposal concern. The gasification slag has been identified as a marketable material of use as a light weight aggregate and road base filler material. Byproduct utilization is an important consideration when evaluating alternative technologies and will become even more important as existing disposal sites close and new sites become more difficult to permit.

Wastewater streams have been thoroughly analyzed and the results show no harmful pollutants. Because of extensive recycling of process water, the wastewater streams are concentrated and are easily treatable in commercial wastewater treatment processes. Texaco demonstrated its proprietary wastewater treatment process in pilot plant operation at Cool Water.

The process water requirements for IGCC plants are approximately one-third less than the requirements of conventional steam-based power plants, since more than half the power generated comes from

the combustion turbine. The water requirements for the coal gasification process are approximately one-fifth of the total plant consumption.

As a result of the superior environmental performance demonstrated at Cool Water, we believe the permitting process for future IGCC plants can be streamlined. Much of the baseline data generated at Cool Water is available to assist in permitting commercial facilities.

COMMERCIAL EXPERIENCE

There are currently three operating, commercial-size TCGP plants. Two more plants are expected to be under construction shortly. These plants are described briefly below.

Prior to the construction of these commercial TCGP units, demonstration units were built and operated by the Tennessee Valley Authority (TVA) in Muscle Shoals, Alabama, and by Ruhrkohle, AG and Ruhrchemie (RAG/RCH) in Oberhausen, Germany.

The 250 TPD RAG/RCH plant operated on coal feed for over 10,000 hours during which new design and materials specifications were developed. Texaco's participation in test runs and data sharing with both TVA and RAG/RCH provided a foundation for the larger commercial design.

TENNESSEE EASTMAN CORPORATION KINGSPORT, TENNESSEE

The Tennessee Eastman Corporation was the first commercially-sized Texaco coal gasification plant. It uses 900 tons per day of coal to produce the hydrogen and carbon monoxide feedstocks for the manufacture of acetic anhydride.

This plant has demonstrated the reliability of the Texaco gasification process by recently completing a twelve month period in which syngas production was interrupted for less

than twenty hours. Gasification plant on stream factors typically exceed 99% here. The plant has gasified nearly two million tons of coal since its startup in 1983.

UBE AMMONIA PLANT

UBE CITY, JAPAN

The Ube plant is the world's first large scale ammonia plant based on coal gasification. The 1650 TPD gasifier produces hydrogen that is fed with nitrogen to the ammonia works.

This plant was constructed in 18 months and was operating at full capacity within its first year of operation in 1984. The Ube gasification plant typically produces on stream factors near 99%

Over two and one half million tons of feed have been gasified at Ube, including over 200,000 tons of petroleum coke.

SYNTHESGAS ANLAGE RUHR

OBERHAUSEN, GERMANY

The Synthesgas Anlage Ruhr plant was constructed by the same companies that built and operated the demonstration sized RAG/RCH plant described above. This 800 TPD plant was started up in 1986.

The TCGP plant produces a mixture of hydrogen and carbon monoxide that is used to produce oxochemicals - plasticizers, drying agents, and detergents.

SHOUGANG COAL GASIFICATION PROJECT

BEIJING, PEOPLE'S REPUBLIC OF CHINA

The Shougang plant will gasify 1170 TPD of Chinese anthracite to produce fuel gas for an existing steel mill and for town gas. This plant is in its final design phases and is expected to begin its construction phases shortly.

LUNAN COAL GASIFICATION PROJECT

SHANDONG PROVINCE, PRC

This 375 STPD TCGP plant will produce hydrogen and nitrogen to feed an ammonia plant. Chinese Lunan coal will be used as the feed. Construction has begun on this plant.

COST AND PERFORMANCE OF TCGP POWER PLANTS

The design of TCGP based power plants have evolved and matured since the construction of the Cool Water plant. This has resulted in substantial reductions in the projected cost of electricity. These developments have paved the way for the construction of new IGCC power plants in the early 1990s.

Performance and cost data for a nominal 440 MW plant using West Virginia bituminous coal and with radiant and convective gas cooling are shown below:

Heat Rate, HHV, Btu/kWh	8900
Capital Cost \$MM	677
\$/kW	1550
30-Year COE, Mills/kWh	49-50
Dispatch Cost, Mills/kWh	17.7
Net Output, MW	437

Heat rate is a measure of overall plant efficiency. It is the total energy content of the feed coal on a high heating value basis divided by the net power output of the plant. In comparison the heat rate from a waste heat boiler and turbine generator at sewage sludge incinerator would be more than 20,000 Btu/kWh.

The capital costs shown include January 1989 installed equipment costs for the entire TCGP based power plant including the oxygen plant, field and home office costs, taxes, and contingencies. Royalties, land, working capital and startup expenses are not included in these costs.

Thirty year cost of electricity (COE) is a levelized cost computed using standard utility methodology which incorporates amortized

capital costs with the operating and maintenance costs of the plant. The plant capacity factor is 80%.

The dispatch cost shown includes the cost of fuel, staffing, maintenance materials, start-ups, catalysts and chemicals, and slag disposal. The delivered coal cost is assumed to be \$30/short ton. Sulfur sales are credited at \$60/long ton. Slag disposal cost is assumed to be \$15/short wet ton.

Overall sulfur recovery is in excess of 98%. Total NOx emissions are less than 42 ppmvd (15% O₂).

THE PRIMARY PROCESS ADVANTAGES OF TCGP ARE:

1. Feedstock Flexibility - The gasifier can accept a wide variety of coals and other feedstocks such as petroleum coke, coal liquefaction residues, pyrolysis char, and coke from tar-sands bitumen.
2. High Coal Conversion - Essentially complete coal conversion is attained, either by once-through operation or by recycle.
3. Compatibility With Existing Gas Processing Technology - Conventional systems for scrubbing and sulfur removal are compatible with synthesis gas processing.
4. Wide Range Of Pressures - TCGP is capable of high-pressure operation, which eliminates or minimizes the need for compression for downstream use in turbines.

7. Simple Gasifier Design - Since there are no internal moving mechanical parts within the gasifier, the operability and reliability factors are high.
8. Modular Adaptability - Gasification can be added to existing plants in modules to provide maximum flexibility when incremental capacity is needed.
9. A Clean Fuel Gas - Raw synthesis gas is easily treated at gasifier pressure to remove contaminants before combustion. Entrained particulates are removed from the raw gas to extremely low levels by conventional water scrubbing. Sulfur, primarily as hydrogen sulfide with some carbonyl sulfide, is removed from the gas using commercially available technology which permits recovery as elemental sulfur.
10. Minimal Process Water Effluent Disposal Problems - The bulk of the process water is normally recovered and recycled to the gasification section. The amount of water which must be rejected to recycle water stream is determined by the water-soluble impurities in the specific coal feed.
11. Slag Can Be Recovered - Extensive environmental studies have been conducted on slag samples from the Montebello Pilot Plant. They indicate that the slag leachate does not violate Resource Conservation and Recovery Act Standards.

TEXACO GASIFICATION - PROJECT CONFIGURATIONS

The Texaco Coal Gasification Process when used in an Integrated Gasification Combined Cycle (IGCC) configuration offers a reliable, economical and environmentally-superior option for power generation. Figure 2 shows a simplified flow diagram of a typical IGCC plant. Power production in such a facility can range from 200 MW to 800 MW, with a levelized cost of power of about 5-6 cents/kWh.

Although IGCC is the most likely configuration for utilizing Texaco's gasification technology in power generation, a number of other variations are possible. A once-through methanol process could allow a small percentage of the syngas (5-10%) to be converted to liquid methanol.

Since conventional boilers and fluidized bed boilers produce only steam, the coproduction alternative when using coal as a feedstock is only available for gasification. Methanol could become a valuable product for sale to the transportation sector. There is a high degree of interest in oxygenated fuels, including methanol, across the U.S. due to the new Clean Air Act regulations. Methanol sales could potentially allow a reduction in the price of power sold to utilities. Sales of other high value products, such as argon, could also lower the price of oxygen which would result in a reduction in the cost of power sold.

In addition to the sale of high value products such as hydrogen, oxochemicals, and ammonia, there is another way to significantly reduce the price of power waste gasification. Texaco has had an active waste gasification research and development program at its Montebello Research Laboratory for several years. With ever-increasing environmental regulations restricting incineration, ocean disposal and landfills, the waste producers are willing to pay high tipping fees to process these wastes. The opportunities for gasifying wastes are favorable. For a given IGCC plant the predominant feedstock would still be coal but the inclusion of certain wastes at levels of 20-25% of the gasifier feed could substantially lower the price of power.

TEXACO WASTE GASIFICATION

Given the ability of the Texaco Gasification Process to deal with a variety of feedstocks and also its ability to destroy organic and inorganic compounds, TGP is an ideal means of converting waste materials into desirable, useable products. This ability has been documented in published environmental studies which also show the

process effluent water to be free of priority pollutants.

Depending upon the physical and chemical composition of the waste stream, waste can either be used as the primary feed to the gasifier or it can be co-gasified along with a high-Btu feed such as coal. The choice is based on many factors. The feed must be slurried successfully; the heating value of the feed must be such that the gasifier temperatures can be maintained; and the fusion temperature of the ash in the feed must be within operational limits. The ratio of waste feed to primary feed can be adjusted to optimize the gasifier operation. Even if a waste stream can be used as the sole feed to the gasifier, blending of the waste with a primary feedstream allows for continuity and stability of operation.

Once the ratio of waste feed to primary feed has been determined, the two feeds can be blended and injected into the gasifier as a single stream or they can be delivered to the gasifier in two feed systems.

CALIFORNIA DEPARTMENT OF HEALTH SERVICES STUDIES

Under grants from the California Department of Health Services, Texaco successfully demonstrated the gasification of low-Btu, liquid hazardous waste to produce synthesis gas and nonhazardous effluent. The emphasis of the Hazardous Waste Reduction Grant Program is to develop opportunities and technologies to reduce the volume or toxicity of hazardous waste generated within California.

The first grant, awarded in 1986, funded two studies in which the feasibility of gasifying liquid and solid wastes streams was evaluated. The goal of the studies was to identify, sample, and analyze hazardous wastes in order to evaluate their potential as added feedstocks to the gasifier. Due to the low-Btu value of the wastes studied, all were considered as supplemental feeds to a base coal slurry. The liquid and solid wastes studied included aqueous solutions with metals and contaminated soils.

The study concluded that all of the wastes studied could be handled by the Texaco Gasification Process. Only minor modifications to the receiving and handling systems would be necessary. The petroleum industry wastes and the aqueous wastes could be mixed directly with the coal to form pumpable slurries. Wastes such as pesticide rinse water and halogenated solvents could be introduced directly to the gasifier through separate feed systems. The products of the waste gasification would be nonhazardous. The only hydrocarbon in the synthesis gas would be trace amounts of methane. The mineral contents of the waste and the coal would form a nonhazardous slag with an acceptable ash fusion temperature. The slag would be nonhazardous based on the strict California Assessment Manual limits.

Under a second grant from the California DoHS, Texaco demonstrated the pilot plant gasification of low-Btu, petroleum production tank bottoms. In December, 1988, Texaco completed approximately 40 hours of pilot plant operations at the Montebello Laboratory demonstrating the use of this hazardous material as a supplemental feed to the Texaco Coal Gasification Process.

The pilot unit was operated at approximately 2400 deg F and 350 psig. The feed to the pilot unit was approximately 20 wt% hazardous waste (600 lb/hr) and 80 wt% coal slurry (2400 lb/hr). A total of approximately 2500 gallon of petroleum tank bottoms obtained from a California oil production field and approximately 35 tons of coal were gasified.

Analysis of the synthesis gas for operation with the dual feed showed that the only hydrocarbon was methane in very low concentration, less than 300 ppm.

During the pilot unit run samples of solids and waste water were taken and sent to a contract laboratory for analyses for trace organics and priority pollutants. Additional samples of the solids were sent for leachate tests. The solids were found to be

nonhazardous based on the California Assessment Manual limits for total and leachable metals and below the detectable limits in reactive sulfides. Both the solids and the waste water were also found free of trace organics and EPA priority pollutants.

SEWAGE SLUDGE STUDIES

Following the successful testing of hazardous wastes it was felt that gasification might also be appropriate for high-volume, low-hazard wastes such as sewage sludge. Because the pumping characteristics of the slurry is an important consideration, the first sludges tested were Carver-Greenfield sludge from Hyperion, Los Angeles and Zimpro heat-treated sludge from Indio, California. Eighteen-hour test runs were performed with each sludge and coal at Montebello in May, 1989.

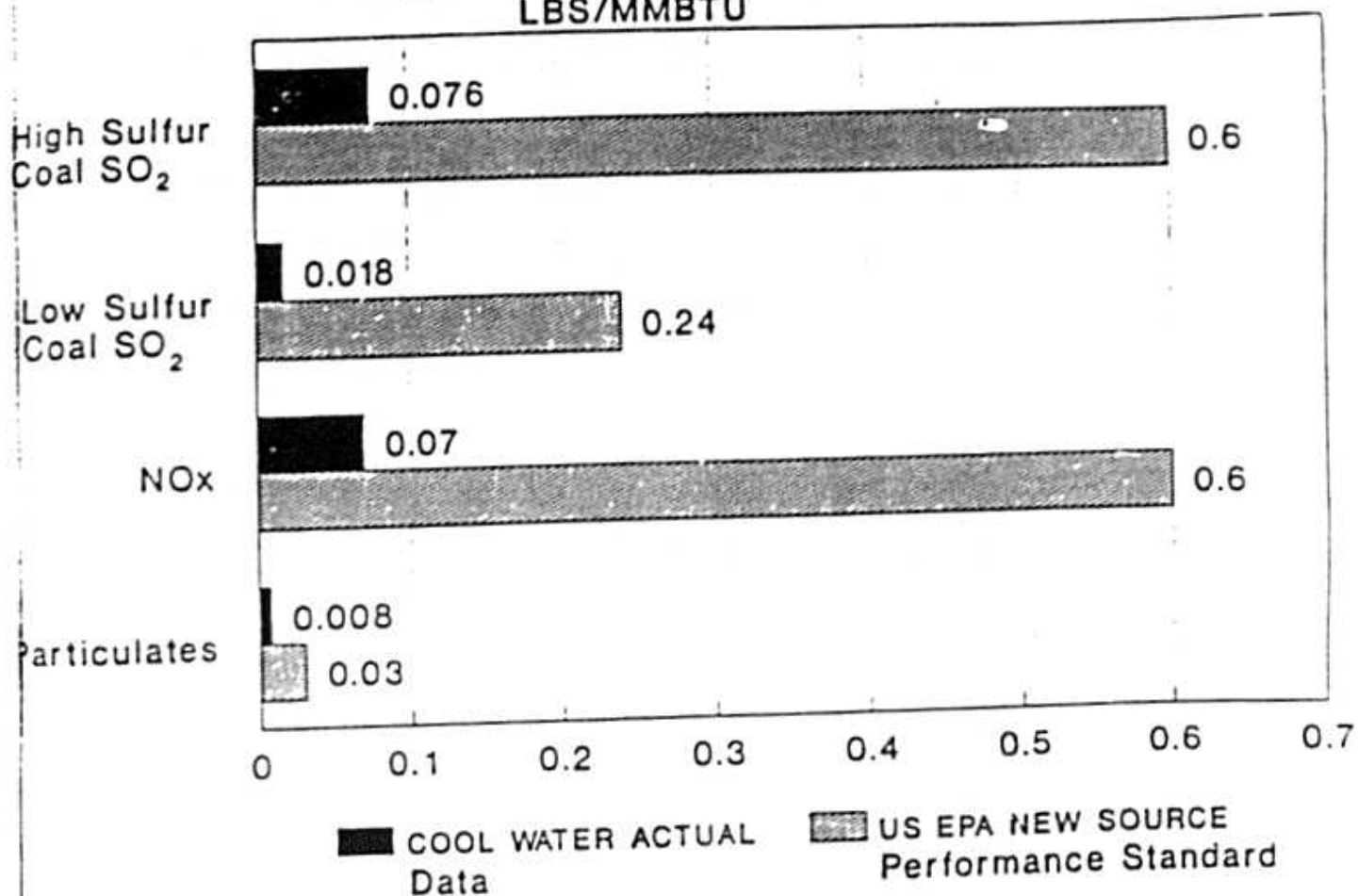
The dry Carver-Greenfield sludge was blended directly with a Pittsburgh No. 8 coal slurry. The Zimpro sludge was blended with the coal before grinding to prepare a slurry. The sludges were easily handled and used as-received with no additional treatment.

The next efforts were directed at preparing sludges from plants with conventional processing. In order to maintain the highest efficiency in gasification there is a limit to the proportion of water carried in the slurry. The viscosity of drier sludge limits its suitability as a feedstock yet too much water in a less viscous slurry affects the gasifier efficiency.

Bench-scale and pilot tests were run at the Texaco Research Center at Beacon, New York to investigate various techniques to improve the rheological properties of sludge. As a result of this work sludge from the Passaic Valley Sewerage Commissioners in Newark, NJ was dried by indirect steam heating before reslurrying with coal. In December, 1990, twenty-eight tons of this dry sludge was successfully gasified at Montebello. The environmental data collected during this test is now being analyzed



TGP and NSPS Environmental Performance LBS/MMBTU



GASIFICATION/COMBINED CYCLE

CLEAN POWER FROM COAL

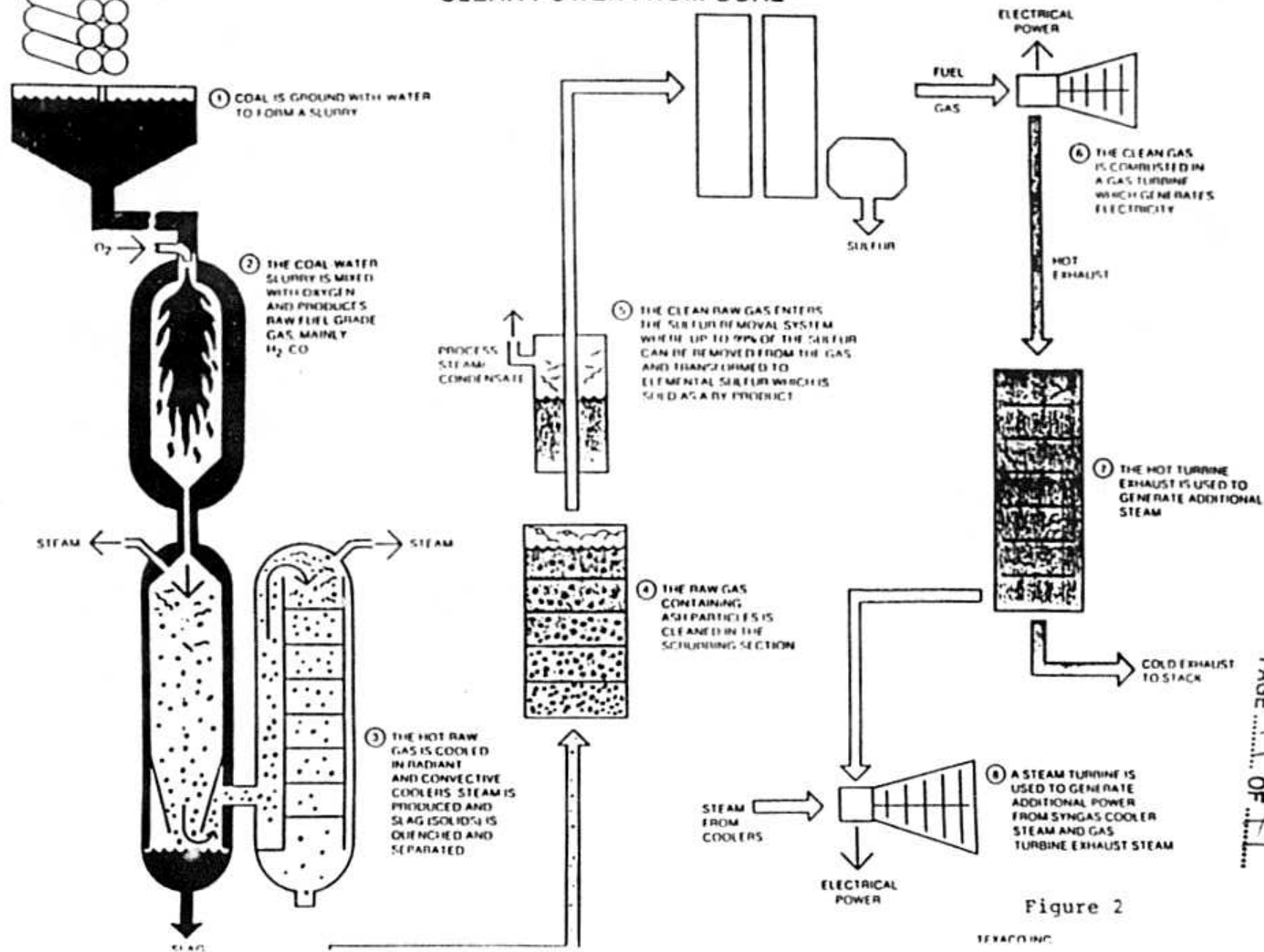


Figure 2

TEXACO INC.

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DOCUMENT NO. 19
PAGE 1 OF 13**

DOCUMENT NO. 19

**TECHNOLOGY FOR ENERGY
AND THE ENVIRONMENT**

Technology for Energy and the Environment

THE TEXACO
GASIFICATION PROCESS



Gasification

As we approach the close of the 20th century, a major challenge facing people worldwide is finding the energy to sustain economic growth and improve quality of life.

Texaco is leading the way in finding environmentally superior solutions to these challenges, developing groundbreaking methods of converting many types of "dirty" fuels into clean energy using the Texaco Gasification Process. The gasification technology can also be used to convert many forms of consumer and industrial waste into useful products, providing an environmentally safe disposal alternative.

The Technology

The Texaco Gasification Process converts hydrocarbon fuels (such as heavy oil, coal, petroleum coke, Orimulsion® and wastes) into a clean-burning synthesis gas, known as Syngas. Rather than burning the fuels (also known as feedstocks) – the conventional method of generating energy – gasification achieves this energy conversion through partial oxidation, significantly reducing emissions of pollutants such as sulfur dioxide (SO_2) and nitrogen oxides (NO_x), which are major contributors to acid rain and smog.

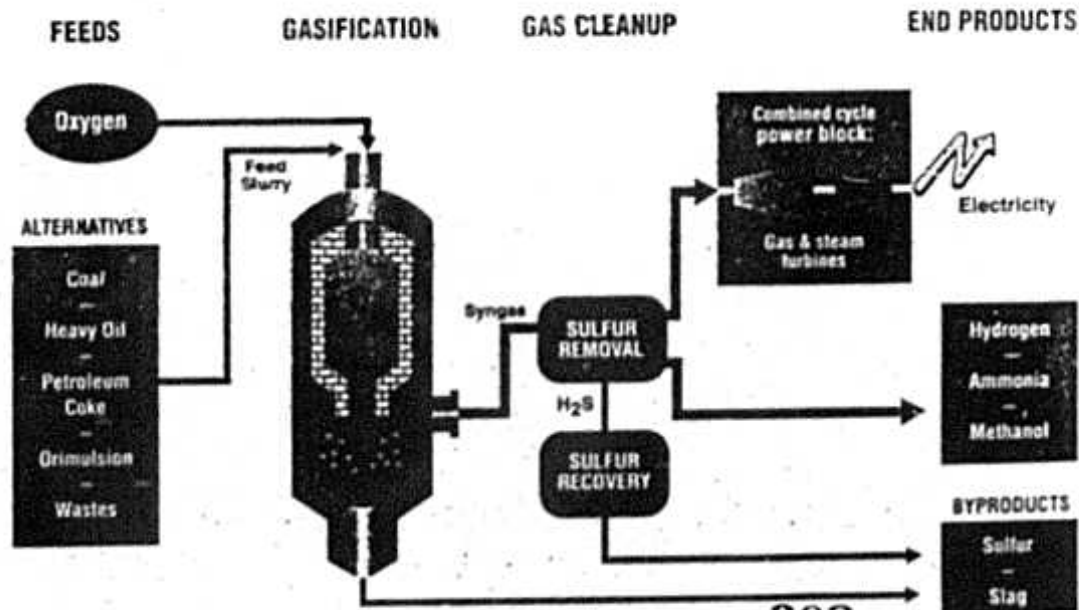
The feedstock – either in a gaseous or fluid state – is injected into the gasifier along with oxygen. In the high temperature ($2,200 - 2,800^\circ\text{F}$), high pressure (400 – 1,200 psi) atmosphere, it is converted into syngas, composed primarily of hydrogen and carbon monoxide, along with carbon dioxide (CO_2) and traces of methane and hydrogen sulfide (H_2S).

Any ash in the feedstock is melted in the process and, when cooled, forms into non-leachable glassy chips known as slag. Heavy metals that exist in the feedstock are encapsulated in the slag. The slag can be safely used for a number of purposes, including cinder blocks, roadbed filler and roofing tiles.

Up to 99 percent of the sulfur present in the syngas can be recovered and sold in an elemental form for fertilizer manufacture. Particulates are removed in the gas cleanup process, leaving a clean gas which is an ideal fuel for generating electricity – much cleaner than burning coal, for example. In addition, syngas has a range of other industrial applications, including the production of hydrogen and other chemicals such as ammonia, methanol and oxochemicals.

Because of its simple design, the Texaco gasifier is both reliable and efficient; and its ability to accept a diversity of feedstocks is a significant – and unique – feature of the Texaco Gasification Process.

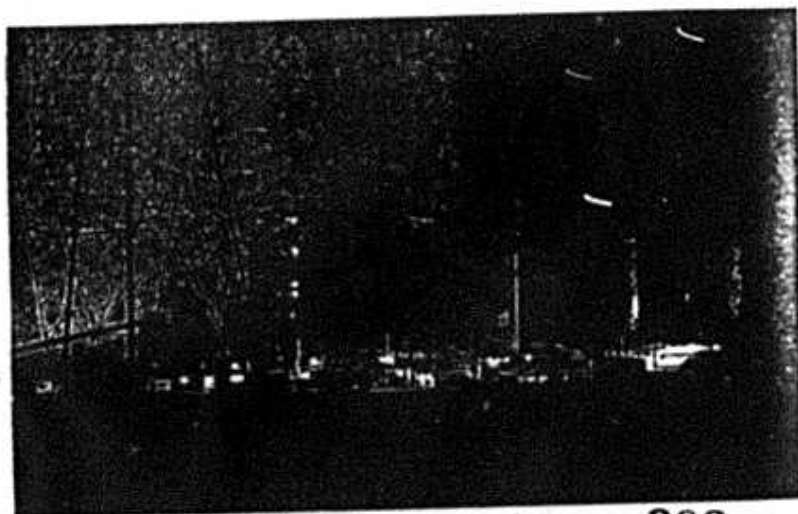
For generating electricity, the Texaco Gasification Process, when integrated with a combined cycle power plant, is environmentally superior to all other systems using the same feedstock.



Fuel Flexibility

Among the most important features of the Texaco Gasification Process is its ability to use many different types of materials as fuels. This makes gasification an attractive technology for a wide range of customers, including utilities, refineries, chemical manufacturers and other industries around the world. Carbonaceous fuels which have been used commercially or demonstrated in Texaco gasifiers include:

- Coal (high- and low-sulfur)
- Heavy oil
- Petroleum coke
- Orimulsion®
- Scrap tires
- Used oil
- Plastics
- Sewage sludge
- Contaminated soil
- Hazardous waste



Currently, more than half the world's electric power is generated from coal as the base fuel. Coal is also an important fuel for the production of chemicals. But increasing environmental concerns demand that cleaner fuels be used unless technologies can be developed to use coal in a cleaner and more efficient manner. Texaco's gasification technology offers an environmentally friendly, commercially proven, reliable and efficient alternative to traditional coal burning methods.

The Cool Water Coal Gasification Program in Southern California was the world's first commercial demonstration of Integrated Gasification Combined Cycle (IGCC) technology, merging the environmentally-superior gasification technology with a highly efficient combined cycle power generation system.

During its planned five year demonstration (1984-89), the Cool Water plant won numerous environmental awards and was considered the world's cleanest coal-fueled power plant.

Coal gasification plants have been licensed worldwide, including the United States, Europe and Asia. In 1992, the Texaco Gasification Power System was selected for a 260 megawatt coal-fueled power project in Florida.

Texaco gasifiers have proven records of performance, having accumulated more than 200,000 operating hours handling over 5 million tons of various coals with wide ranges of sulfur and ash fusion temperatures.

Another important environmental advantage of the Texaco Gasification Process is its ability to gasify waste materials combined with coal. Coal supplements the heating value of low-Btu wastes, thus improving the efficiency of the waste-to-energy process.

CARBON DIOXIDE EMISSIONS

A major concern in international petroleum refining is developing uses for heavy, low-grade crude oils. At the same time, environmental considerations are making it increasingly difficult to market heavy oil residues containing high levels of sulfur and heavy metals.

The Texaco Gasification Process can utilize heavy oil residues as feedstocks to produce clean syngas for electric power generation, hydrogen production, other industrial fuel applications, or for the manufacture of a wide variety of chemicals. In the United States, for example, Texaco gasifiers are used to produce hydrogen from various waste or low-value oils at Texaco refineries.

Meanwhile, gasification of bottom-of-the-barrel residues at refineries in Italy will produce electricity along with hydrogen and steam. Stringent environmental regulations in Europe limit the use of feedstocks such as heavy oil residues for direct combustion, making gasification an ideal technology for this fuel resource.

Unlike other processes, a gasifier does not emit soot or particulates and most process water is recycled.

For heavy oil residues and similar wastes, the Texaco Gasification Process offers an environmentally acceptable alternative to costly waste handling and disposal.



Petroleum coke is an oil refinery byproduct with many of the characteristics of coal. It is a solid, with a heating value of approximately 14,000 Btu/lb and a sulfur content of up to eight percent. U.S. domestic production of petroleum coke stands at approximately 70,000 tons per day. Most of this is presently shipped overseas to be used as a fuel for conventional boilers. However, when petroleum coke is burned in conventional boilers, it results in significant levels of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) emissions, even when equipped with scrubbers.

Gasification of petroleum coke has been practiced commercially at a large Texaco gasification plant since 1984, and

has been demonstrated to be the cleanest method for converting this resource into clean energy. Over 98% of the sulfur in the coke can be captured, converted to elemental sulfur and sold as a valuable byproduct. Emissions of nitrogen oxides (NO_x) and particulates are controlled at extremely low levels; thus both air and solids emissions are significantly reduced.

Texaco gasification plants can be built alongside refineries producing the petroleum coke, thereby converting it onsite to a combination of power and steam for the refinery, and electricity for the surrounding community.

With easy handling characteristics and a competitive price structure, Orimulsion® is a new fuel substitute for coal. This fuel, a bitumen-in-water emulsion containing typically 70 percent bitumen and 30 percent water by weight, may be used directly in the Texaco Gasification Process.

Orimulsion is produced by Bitumenes Orinoco SA (Bitor) of Venezuela. With current technology, some 270 billion barrels are available, making the field approximately equal to Saudi Arabia's proven oil reserves.

Test results have shown that Orimulsion is an excellent feedstock for the Texaco Gasification Process. The water contained in the emulsion serves as a temperature moderator, thus reducing overall water requirements.

Gasification is environmentally superior to other technologies using Orimulsion because sulfur and metal contaminants are removed and captured more efficiently.

Compared with the gasification of typical coal/water slurry feedstocks, Orimulsion gasification results in better thermal efficiencies and higher yields of syngas.

PAGE 9 OF 13

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Because of their convenience, flexibility and low cost, plastics have become an important part of our society – in packaging, household goods, automobiles and elsewhere in the home and workplace. Unfortunately, because plastics have proven so difficult to recycle, substantial volumes are entering landfills. Since most plastics are not biodegradable, municipalities and industries are faced with a sizeable environmental challenge.

The Texaco Gasification Process offers a potential option for the beneficial reuse of plastics. Work is

underway to design a commercially viable system of using a wide variety of plastics as a feedstock for the gasifier. Studies show that sulfur, metals and other trace materials can be removed from the gas stream, yielding a clean syngas for the manufacture of chemicals and new plastics. Syngas can also be used to generate electricity.

Among the advantages of plastics gasification is the ability to convert many types of plastics to syngas, including automobile wastes and household plastics. Also, sorting of plastics is not required, eliminating a high cost, labor-intensive step.

*Industrial and consumer plastics
can be recycled into clean energy,
industrial chemicals and new
plastics through gasification.*

Municipal sewage sludge is among the many carbonaceous wastes that can be gasified to produce clean energy while ensuring the destruction of harmful pollutants. Sludges from California, Texas and New Jersey have been successfully tested with coal, demonstrating that the Texaco Gasification Process is a viable method of producing energy from this waste material.

Municipalities currently dispose of sludge by incineration or land application. However, incineration is controversial because of limitations on the ability to control emissions of sulfur and metals such as mercury and lead. Land application, meanwhile, can often cause unpleasant odors, and there are limitations on its use on farms or parklands.

While typical incinerator exhaust treatment is usually limited to about 90 percent sulfur removal, standard Texaco gasifier designs can remove more than 98 percent of all sulfur. Furthermore, the sulfur recovered in the gasification process is high-purity elemental sulfur with a proven market value. Also, the Texaco Gasification Process destroys hazardous organic materials and pathogens, and heavy metals are contained.

The Texaco Gasification Process presents an environmentally superior alternative to other methods of destroying sewage sludge.

Gasification is preferable to other methods of sewage sludge disposal because it captures metals in a non-leachable slag form, while producing clean syngas.

A pressing environmental concern is the clean-up or remediation of sites where soil and groundwater have been contaminated by chemicals. Complex hydrocarbon and metal-containing compounds often constitute a major class of contaminant found at these sites.

The Texaco Gasification Process can convert contaminated soils to non-hazardous products in an environmentally safe manner. The process converts hydrocarbons into syngas and lesser

amounts of water, carbon dioxide and methane, while the soil melts at the high process temperatures and, upon cooling, forms a non-leachable slag.

At Texaco's Montebello Research Laboratory in California, gasification tests demonstrated that, using coal as a supplementary fuel, gasification can convert a low heating-value waste into useful syngas and an inert slag. The syngas was essentially free of hydrocarbons and could be purified easily by standard methods.

The success of these tests demonstrates the potential of the Texaco Gasification Process for the destruction of hydrocarbon-contaminated wastes, particularly contaminated soils from waste sites.

When mixed with coal or other high energy feedstocks, contaminated soil can be gasified, eliminating a potentially hazardous waste and producing clean energy.



The ability of the Texaco Gasification Process to destroy organic compounds and capture metals in non-leachable slag makes it an ideal means to convert waste materials to desirable, useable products. The process offers an efficient, acceptable and economic alternative to land disposal or incineration.

The ability of Texaco's technology to process hazardous wastes effectively has been documented in published environmental studies. These studies also show the process effluent water to be free of priority pollutants.

Texaco's Montebello Research Laboratory has worked closely with the California Department of Health Services to identify hazardous wastes that could be feedstocks to the gasification technology.

Depending on the physical and chemical composition of the hazardous waste stream, it can either be used as the

primary feed to the gasifier or it can be gasified along with another feedstock, such as coal or low-value oils. In the California studies, due to the low heating value of the wastes involved, all were considered to be supplemental feeds to a base coal slurry. The California studies concluded that all the wastes could be used as feedstock for the Texaco Gasification Process.

An extensive study has been conducted by the U.S. Environmental Protection Agency under its *Superfund Innovative Technology Evaluation (SITE) Program* to further validate the performance of the Texaco Gasification Process for hazardous wastes.



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DOCUMENT NO. 20
PAGE 1 OF 2

DOCUMENT NO. 20

AWARDS BY TEXACO FOR GASIFICATION
PROCESS AND COOL WATER PROGRAM

Awards

PAGE 2 OF 2

THE FOLLOWING IS A LIST OF AWARDS EARNED BY THE TEXACO COAL GASIFICATION PROCESS AND THE COOL WATER PROGRAM.

1987 ASME ENERGY RESOURCES TECHNOLOGY AWARD.

Presented by the American Society of Mechanical Engineers to Cool Water as the most outstanding example of advancing mechanical engineering in energy resource related technology.

1986 ENERGY INNOVATIONS AWARD.

Presented to Cool Water by the California Energy Commission.

1986 OUTSTANDING ENGINEERING ACHIEVEMENT AWARD.

Presented to Cool Water by the Institute for the Advancement of Engineering. In announcing the award, IAE officials called Cool Water "very possibly the world's cleanest coal using plant."

1985 KIRKPATRICK CHEMICAL ENGINEERING HONOR AWARD.

Awarded to Texaco by Chemical Engineering Magazine. Coal Gasification for Electric Power Production was cited as an excellent example of the diversity of the process.

1985 ENVIRONMENTAL PROTECTION AWARD.

Presented to Cool Water by Power Magazine. This annual award recognizes utility industry achievements in protecting the nation's natural environment.

1984 WALTER FLOWERS ACHIEVEMENT AWARD IN SYNTHETIC FUELS.

Awarded to Texaco by the National Council on Synthetic Fuels Production for Development and Commercialization of the Texaco Coal Gasification Process.

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DOCUMENT NO. 21
PAGE 1 OF 15

DOCUMENT NO. 21

USE OF THE UBE COAL
GASIFICATION SLAG

Commercial Application of Slag
from
Texaco Coal Gasification Plant
in
Ube Ammonia

By
Kotaro Katagiri
Ube Industries, Ltd.
Tokyo, Japan

Presented At :
IEA Expert-meeting
on
the Use of Coal-gasification Slag

May 10th - 11th, 1990
Arnhem, The Netherlands

Contents

ABSTRACT	1
INTRODUCTION	2
OPERATING EXPERIENCE	3
NEW APPLICATION OF SOLID DISPOSAL	4
LIGHT WEIGHT AGGREGATE	5
CONCLUSION	8
TABLE AND FIGURE	9

ABSTRACT

In Ube Ammonia Industry Co., Ltd., we have a commercial Texaco Coal Gasification Process (TCGP) plant for ammonia manufacturing 1,000 metric tons a day from 1,500 metric tons coal, which started operating, in August, 1984.

Since the beginning of its plant operation, the slag from gasifier has been discharged and utilized as a part of raw material for our cement factory. After intensive research and development work by our cement division, in October, 1987, we started producing a porous light weight aggregate made from the coarse slag from Ube Ammonia and put it on the market in Japan. And we have a feeling there is a great deal of potential market in this field due to the increase of client's demand for our product. Recently, the other utilization of coal gasification slag has been also studied for market research by Ube Ammonia.

In this paper, we present the commercial application of slag from Texaco coal gasification plant in Ube Ammonia.

INTRODUCTION

In 1972, Ube Ammonia Industry Co., Ltd. commenced its operation as an ammonia manufacturer by steam reforming plant using naphtha and later LPG. However, through the experience of the two oil crises in 1973 and 1979, we had to change our strategy heavily dependent on imported petroleum. In order to cope with those energy crises, the world's first large-scale ammonia syngas plant based on the Texaco Coal Gasification Process (TCGP) was completed to replace the existing steam reforming plant in July, 1984. Since its start-up, Ube Ammonia has been successfully producing the rated capacity of 1,000 metric tons of ammonia from 1,500 metric tons of coal/petroleum coke a day. The total amount of coal and petroleum coke consumed from the beginning to March 31, 1990 is about 2.0 and 0.5 million metric tons respectively.

While operating the main ammonia production plant, we have discharged the slag which has been utilized as raw material of cement.

As other waste slag utilization from coal gasifier, the porous light weight aggregate "U-Light" has been commercially manufactured, since October, 1987. Currently, the supply of U-Light quantity becomes very tight in Japan due to the increase of client's demand. Thus, we believe there is a further potential market in the field of the porous light weight aggregate based on our technology.

In the following chapters, we brief on the overall operating experience of Ube Ammonia in terms of feedstock and focus on U-Light technology as commercial slag utilization.

OPERATING EXPERIENCE

In Ube Ammonia, in July, 1984, we accomplished the construction of Ube Ammonia coal gasification plant by Engineering Div. of Ube Industries, Ltd. Our ammonia plant consists of air separation, CO shift, acid gas removal, and ammonia synthesis as well as Texaco coal Gasification plant.

In early August, 1984, we started manufacturing ammonia from coal. We are very satisfied with our continuous commercial operation for almost six years. So far we have mainly gasified four kinds of coal such as Australian, South African, Chinese, and Canadian whose ash contents are ranging from 7 to 15 wt%. We also have employed petroleum coke with less ash content as feedstock since April, 1986, in order to make its diversification.

The amounts of coal and petroleum coke processed in the plant are approximately 2.0 and 0.5 million metric tons respectively since its start-up by March, 1990 as listed in Table 1.

Although this indicates that the consumption of petroleum coke over coal is gradually increased year by year, we think that this will not affect the slag availability as feedstock for U-Light production against major ammonia production.

As for the U-Light manufacturing plant, we have satisfactorily experienced for two years and half commercial operation with a capacity of 1,000 m³/month in Ube Cement factory.

As the demand of U-Light has been increased, we expect that the U-Light plant capacity should be enhanced to meet the client's request in the future.

NEW APPLICATION OF SOLID DISPOSAL

One of merits for high temperature coal gasification like Texaco Coal Gasification Process (TCGP) is an easiness of slag disposal due to no leaching substances. When the coal water slurry is gasified with oxygen, the ash in the coal is melted down to be slag in gasifier under high temperature and high pressure, and the slag becomes glassy at around 1300°C to 1400°C, while the clean syngas can be generated to utilize for many down-stream application such as C1-chemistry as well as so-called IGCC.

In case of TCGP, there are two kinds of slag such as fine and coarse discharged out of Texaco gasifier. The fine slag is carried out by track to our Isa Cement Factory as a part of raw material for cement. The remainder is coarse slag to be transported also by track to our Ube Cement Factory for manufacturing porous light weight aggregate as well as cement. At the beginning of Ube Ammonia gasification plant operation the whole discharged slag was only utilized for our cement factory. Although the quantity of slag is very small compared with the total necessity of cement raw material, the slag should be appreciated as some substitute of clay and fuel saving. In this respect, later, the cement division of UBE Industries, Ltd. has managed to research and develop more valuable way of slag utilization. In October, 1987, we commercially started the manufacturing of porous light weight aggregate made from our slag and are marketing it in Japan as very useful material whose registered name is "U-Light".

Recently, Ube Ammonia has also made an effort to have a market research for other application of coal gasification slag. That is an artificial marble, terrazzo. As we succeeded in making beautiful black terrazzo with excellent hue, we will put it to practical use if there is a potential market.

LIGHT WEIGHT AGGREGATE

The slag from gasifiers has, as shown in Table 2, comparatively low content of SiO_2 , and high content of Fe_2O_3 and CaO and some amount of unburnt carbon which work as flux and blowing agents. There are no harmful substances in terms of environmental concerns and cement chemical reaction due to the high temperature heat treatment in the gasifier.

Figure 1 shows the composition diagram for bloating materials as well as coal gasifier slag, in which the dotted line represents the limitation of bloating.

The typical composition of the coal gasifier slag does not seem to meet the necessary conditions for slag foaming proposed by Dr. C. H. Riley because of such high flux content as CaO and Fe_2O_3 . However, a good sphere shape balloon can be actually obtained by our developed method and be supplied as final product at range of diameter between 0.3 mm and 10 mm with four grades.

During the research and development work, we employed electric furnace and microscope to observe the slag shape change, and to measure bulk density and water absorption etc. under the atmosphere of air.

At the stage of preliminary research work, we only had focused on how to make more solid material rather than porous one. But, finally, the opposite phenomenon to bloat the coal gasification slag was found by chance.

The ballooning behavior is different from each coal kind, thus we have a test schedule with three phases to assure the manufacturing of good U-Light.

In commercial stage, this slag balloon, U-Light, can be produced in counter or parallel flow type rotary kiln or flash furnace in the same way as other inorganic balloon production in public.

Figure 2 shows the production process block flow for U-Light using a counter flow type rotary kiln.

The optimum blending ratio between cement, and U-Light for mortar should be decided by client in terms of compressive strength as described in Figure 3.

Table 3 indicates the superiority of U-Light whose water absorption is one third of conventional light weight aggregate made from perlite and collapsing strength is three times bigger than that. The one of test results on cement mortar mixed with U-Light as its application is tabulated in Table 4. Just for your reference, the mortar flow under the table means the spread diameter of sample mortar on the turning table after 15 times rotation, which is a very familiar value to check its fluidity by Japanese plasterer.

The remarkable features of U-Light are summerized as follows :

- Sphericity in shape and smooth glass-like surface
- Extremely low water absorption
- High strength but extra-low bulk density
- High refractoriness and insulation

Based on the above characteristic, the major application using U-Light could be as follows :

- Most suitable building materials for flooring, walling and roofing especially because of extra-low bulk density and high refractoriness and insulation

- Good pumping characteristic and resistant to freeze and fusion because of extra-low water absorption
- Suitable for farming and gardening because of odorless and germfree balloon

Among those usage, U-Light has been commercially sold for pre-mixed mortar for building wall in Japan.

There are already many inorganic light-weight aggregates on a commercial basis such as glass balloon from an artificial raw material, as well as perlite and expansive shale and obsidian from a natural resource.

We think our U-Light has several advantages against those existing aggregate in terms of economics, low water absorption, and high strength. Especially, the low water absorption enables users to make stronger mortar and precast concrete without any crack by using U-Light.

Incidentally, UBE has applied for a patent on this "U-LIGHT" in Japan, United States of America, United Kingdom, South Africa, Sweden and China. In this respect, UBE is willing to license the U-Light process to each personal who is interested in as treatment method for the waste solid from coal gasification plants.

CONCLUSION

In this paper we discussed the commercial application of coal gasification slag based on our two-years-and-half experience mainly for porous light weight aggregate. There are the other applications as cement raw material experienced and Terrazzo under market research.

Except for those utilizations, we will manage to find out other applicable method intensively by integrating our each division's expertise.

We predict that the quantity of coal gasification slag will increase remarkably in conjunction with the further installation of coal gasification plant throughout the world in the future.

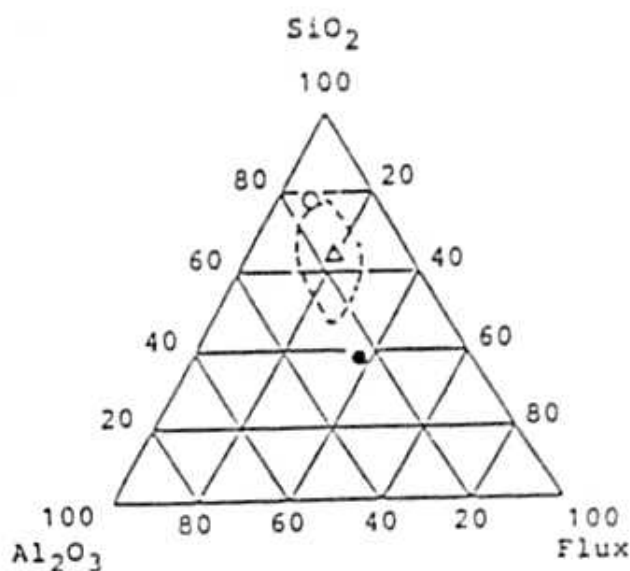
In this respect, there will be alternative measures to change the bothersome quantity of waste slag into more valuable material than conventional reclamation. It may not be exaggerated to say that U-Light technology will turn a misfortune into a blessing.

Table 1 Annual Consumption of Feedstock

YEAR	COAL	PC	TOTAL
1984 (from July)	137	0	137
1985	476	0	476
1986	426	46	472
1987	314	123	437
1988	303	162	465
1989	273	181	454
1990 (by March)	101	32	133
TOTAL ($\times 10^3$ MT)	2,030	544	2,574

Table 2 Chemical Composition of Coal Gasifier Slag

Chemical Composition (%)									Unburnt C (%)
Ig.loss	SiO ₂	Al ₂ O ₃	Fe ₂ O ₃	CaO	MgO	SO ₃	Na ₂ O	K ₂ O	
3.1	38.8	22.1	9.4	19.2	1.6	0.2	1.6	0.6	2.9



● : Coal Gasifier Slag

○ : Obsidian

△ : Shale

--- : Dr. C. M. Riley's Ballooning Area

Figure 1 Triangular diagram

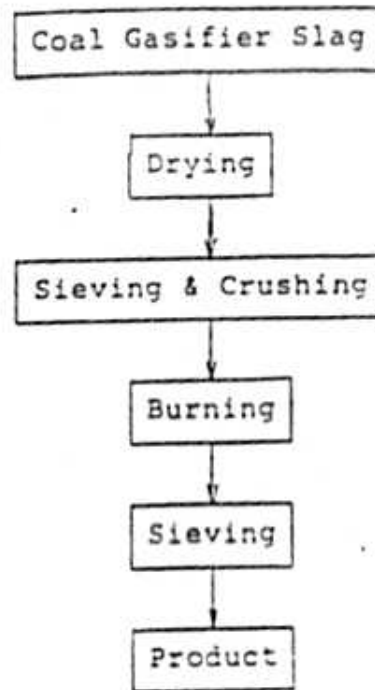


Figure 2 Process Flow Sheet

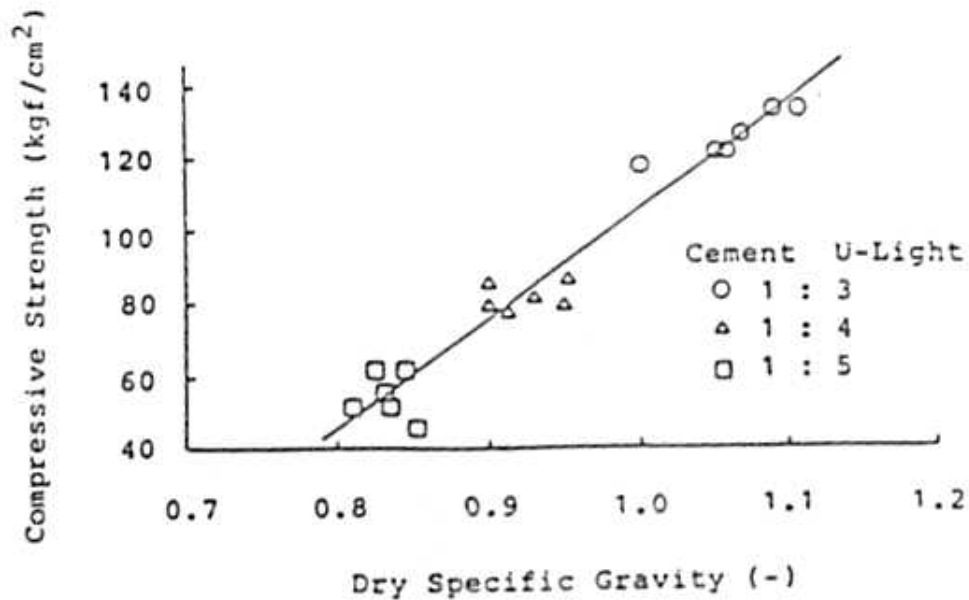


Figure 3 Relation between 28-days-compressive Strength and Dry Specific Gravity*

Table 3 Quality of U-Light*

	Raw Material	Particle Diameter (mm)	Bulk Density (kg/l)	Water Absorption(%)	Collapsing Strength (kgf)
U-Light	Coal Gasifier Slag	0.15-10	0.15-0.45	5.0	2.1
Conventional Product	Perlite	0.15-15	0.10-0.40	16.9	0.7

Table 4 Test Results on Cement Mortar Mixed With U-Light*

Volumetric Mixing Ratio Cement : U-Light	Bending Strength (kgf/cm ²)	Compress Strength (kgf/cm ²)	Dry Specific Gravity (-)	Water Absorption (%)	Thermal Conductivity (kcal/mh°C)
1 : 3	27	120	1.051	27.8	0.205

Mortar Flow = 180 ± 10 (mm)

(*) NOTE : Those figures are based on the experimental method by JIS.

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PAGE 1 OF 8**

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**PAPER ON TEXACO
GASIFICATION PROCESS (EPRI)**

Texaco Gasification: Powering the 90's

William E. Preston
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4800 Fournace Place
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Introduction

In the latter stages of the 1990's, Texaco Gasification Power Systems (TGPS) have come of age. Ten years ago, Texaco, as a member of the Cool Water Coal Gasification Program, successfully demonstrated that the Texaco Gasification Process could be mated to a combined cycle power plant.

This technology has matured in the intervening years and in the 1990's, nearly 2000 megawatts of power capacity may be installed that will be fueled by syngas produced by Texaco's gasification process.

The first part of this paper will give an overview of these new power projects, each now in some stage of engineering and construction. The second part of the paper will focus on the El Dorado Gasification Project, a project that embodies exciting new directions for the TGPS.

Background

The Texaco Gasification Process was developed in the late 1940s. It was intended to produce hydrogen and carbon monoxide - syngas - for chemical plant and refinery applications. It was originally designed to be fed natural gas. In the 1950s, it was modified for heavy oil feeds, and in the 1970s for solid feeds like coal and petroleum coke.

Texaco gasifiers soon will produce 2.9 billion standard cubic feet of syngas per day in thirty-seven currently operating installations around the world and twelve new installations now in detailed engineering and construction. Much of this capacity still is used for chemicals production. But with the committed projects discussed in this paper, at least 25% of the syngas generated by Texaco gasifiers will be used for power production by the end of the decade.

Among commercially proven technologies, Texaco Gasification Power Systems based plants remain the most environmentally benign means of generating electricity from sulfur-containing feedstocks. TGPS plants emit a fraction of the NO_x and SO_x air pollutants that are produced from conventional or fluidized bed boiler installations. And even the most advanced boiler systems produce solid wastes in quantities far in excess of those produced in TGPS plants.

Texaco Gasification
Page 2

Texaco Gasification to Power in the '90s

In the latter half of the 1990s, Texaco gasification to power plants will become a significant new source of electric generating capacity. Six new gasification to power facilities are committed that will generate a nominal net total of 1765 MW. Other projects are in various stages of development that may push this total to 2000 MW.

Texaco has issued licenses for the following projects. All megawatts given are net outputs:

1996 Startup: Polk Power Station, Tampa Electric Co., 260 MW
El Dorado Refinery, Texaco Refining and Marketing Inc., 35 MW

1997 Startup: Falconara Refinery, API Energia S.p.A., 220 MW

1998 Startup: Sarlux Project, SARAS S.p.A., 500 MW
Sicily Refinery, ISAB S.p.A., 500 MW

1999 Startup: Sannazzaro Refinery, AgipPetroli S.p.A., 250 MW

The Polk Power Station will be fed by coal. The El Dorado Project will be fed by petroleum coke and refinery waste streams. The four Italian projects will be fed by heavy oil or asphalt.

The Polk Power Station will be the first coal gasification based power plant since the Cool Water Plant completed its demonstration in 1989. The Polk unit is designed to be the most efficient, and cleanest, coal fired power plant in the country.

The last four projects listed above are at Italian refinery sites. Two forces in Italy have driven their accelerated interest in Texaco gasification to power:

- *Italy is in need of new power generation*

Fifteen percent of its power is now imported, nuclear power is banned, and 50% of its domestic power production is from combustion of high sulfur fuel oil. To address this power shortage, the Italian government has offered incentives for independent power production.

- *Heavy fuel oil is dropping in value in Europe*

European Economic Community directives call for reduced SOx emissions, which will reduce the general demand for high sulfur fuel oil. The Italian national electric utility, ENEL, will cease purchase of high sulfur fuel oil in 1997. Most of this utility fuel oil is generated by Italian refiners.

Texaco Gasification
Page 3

Gasification to power is an attractive way for Italian refiners to benefit, rather than to be penalized, from both of these forces. By feeding their heavy oil fractions to an integrated gasification combined cycle (IGCC) plant, a potential waste problem is converted into a major new revenue source - clean power for themselves and for export.

These refiners also will take advantage of numerous refinery synergies with gasification. They will be free to refine lower cost, heavy high sulfur crudes without suffering penalties for producing more high sulfur heavy ends. They may reduce SOx and NOx emissions by gasifying, rather than burning, their fuel oil. Many of these refiners will co-produce hydrogen from the syngas at low cost for their refineries.

Many of these same driving forces for refinery IGCC construction are also developing in other European countries. In the U.S., petroleum coke production is a more common product of the heavy ends of refinery processes. Coke is dropping in value in the U.S. for many of the same reasons that heavy oil is in Europe.

Texaco is continuing to actively develop gasification to power projects world-wide.

The El Dorado Gasification Project

The El Dorado Gasification Project is of significant strategic importance for several reasons:

- It will demonstrate that small, low capital cost gasification to power plants are economical.
- It will demonstrate that waste streams may be converted by gasification to valuable products in an environmentally superior way.
- It will demonstrate that, in the right applications, gasification to power is more economical than natural gas to power.
- It will demonstrate that adding gasification power plants to a refinery improves the efficiency and flexibility of the existing operations.

Small: The El Dorado Gasification Project will be fed by 166 short tons per day (tpd) of petroleum coke and 6-16 tpd of refinery waste streams. The gasification plant is sized to gasify only the lowest value streams produced by the refinery. Startup is scheduled for mid-1996.

Texaco Gasification
Page 4

Syngas is fed to a combustion turbine-generator along with natural gas. By heating value, the turbine is loaded with one-third syngas and two-thirds natural gas. By volume, the reverse is nearly correct.

Products of this refinery unit are 35 MW net power, 180,000 pounds per hour of steam, and pressurized air, nitrogen and oxygen. This amounts to the total power needs of the refinery with no normal export power, about 40% of its steam requirements, all of its nitrogen requirements, and supplementary oxygen and instrument air for its refinery operations.

The capital cost of the unit will be \$66 million, in as spent dollars, excluding owner's costs. This installed cost includes all of the new equipment required for the unit, including its integrated air separation unit, liquid and solid feed preparation, syngas production facilities, and the power block. Home office engineering, field indirects, and contingencies are also included.

The unit will use existing waste water treating, sulfur recovery, and flare systems in the refinery.

With owner's costs, including owner project management, insurance, project development costs, startup costs, spare parts, permitting costs, and other costs, the project will cost about \$75 million in as-spent dollars.

Waste: This unit will be fed by the portion of the petroleum coke generated by the refinery that has become unprofitable to market. Pending Kansas Department of Health and the Environment (KDHE) approval, it will also be fed by various refinery waste streams of zero or negative value to the refinery.

The gasifier will convert these low-value streams to clean syngas. The unit will also produce pure sulfur and fuel-grade solids as by-products. The plant is not expected to produce any significant quantities of solid waste, and will have exceedingly low air emissions.

The project has gained enthusiastic support in the area, as it has the potential to substantially reduce, or even eliminate, organic waste disposal from the plant. Lower truck traffic, lower waste handling risks, and reduced incinerator emissions in the area will result.

Economics: The El Dorado refinery had investigated natural gas fired cogeneration at their plant and rejected it due to poor economics. The avoided cost of power to the refinery in the area did not justify this sort of project.

The gasification to power project has economics that are superior to those of a simple natural gas fed cogeneration project. There are three essential reasons for this:

Texaco Gasification
Page 6

- All of the gasifier feeds are of low or negative value to the refinery.
- The project has several synergies with the existing refinery operation.
- No new natural gas will be purchased for this project.

The gasification process's ability to produce a valuable product - syngas - from the lowest valued streams is a key to the success of this project. Most power projects' cost of power contains a variable fuel charge that is a major portion of its cost. In this case, the fuel charge is zero or negative.

Many of this project's synergies with the refinery will be discussed below. By helping the existing operations produce refined petroleum products less expensively, the project takes on the higher rates of return usually associated with refining projects rather than the lower returns usually associated with utility projects.

The natural gas that is routed to the turbine in this project is gas that normally feeds the refinery's gas-fired boilers. A compensating amount of steam is produced by the new, efficient heat recovery steam generator. Because the refinery will require no new gas purchases for this project, the price and variability of natural gas do not impact this project's economics.

Refinery synergies: Texaco gasification was developed as a refining and chemical plant process. Thus it should come as no surprise that it can bring value to the existing operations of such plants beyond the simple production of power and steam. This gasification to power project gives the refinery:

- *Long term control of its major operating expenses*
Like any cogeneration project, the refinery's power costs will now be well defined and within their control. Unlike other cogeneration projects, their nitrogen, supplementary oxygen, and waste disposal costs will also be defined and controlled.

- *Increased flexibility in crude running capability*
The gasification unit's presence will allow the refinery to process a wider variety of crudes. The plant will have greater ability to run lower cost crudes - with higher sulfur contents and more heavy ends - due to sulfur plant debottlenecking with oxygen and due to having a long term home for its lowest quality coke.

- *Reduced exposure to waste disposal liabilities*
To the extent that the plant is allowed to gasify its own waste products, it will not incur the risks associated with their disposal by third parties.

Texaco Gasification

Page 6

- *Improved plant reliability*

Because their current sources will not be cut-off, the plant will achieve greater steam, power, nitrogen, and plant air reliability. This will nearly eliminate refinery unit shutdowns and off-spec products upon re-starts due to power surges or outages. Steam interruptions due to boiler problems will also be nearly eliminated.

- *Potential for chemicals co-production*

The refinery does not have a current need to use syngas for its value as a petrochemical feedstock. Should market or regulatory conditions change in the future, however, the gasification operation could be easily expanded to co-produce hydrogen, methanol, or other important petrochemical feedstocks.

Current Directions

Texaco is aggressively moving to expand the use of the TGPS. To do this, full advantage must be taken of the unique capabilities of the process. Project development efforts must capitalize on the ability of the TGPS to:

- Beneficially use low value feedstocks
- Produce high value products
- Perform with superior environmental results
- When applicable, add value to existing operations

The TGPS is fully capable of converting very low quality feeds to valuable products. This is a powerful economic driving force for gasification. New environmental restrictions will continue to reduce the value of heavy, high sulfur hydrocarbons and eliminate many current means of waste disposal.

In the past, this has meant projects fed by high sulfur coal, heavy oil, and petroleum coke. We now add refinery and chemical plant waste streams, waste oil, contaminated soil, waste plastics, used tires, waste water treating sludges, and other wastes to this list of potential feeds where applicable.

The products of the TGPS are, by contrast, of high value. Products such as power, steam, hydrogen, and carbon monoxide have been the foundations of the gasification business. We now add nitrogen, oxygen, methanol, sulfur-free fuel gas, and other co-products to the list of products that can add value to the project.

The TGPS remains among the world's most environmentally preferred means of producing the many products just discussed. In the past, the process' ability to far exceed emissions standards made for good public relations, but had little economic value.

Texaco Gasification
Page 7

Now, the ability to assign value to NOx and SOx credits can add a significant revenue stream to projects. In other cases, allowing shutdown or re-fueling of existing boilers saves the high operating and maintenance costs associated with stack scrubbers.

Seeking out opportunities to allow gasification to synergize with existing operations can pay big economic dividends. In many instances, small adjustments to the new TGPS facility allows significant benefits to existing processes that are bottlenecked, that rely on outside gas purchases, or that are fed by expensive or high polluting processes that make syngas or its components.

Gasification to power projects became a difficult economic sell in the years following the end of Cool Water Project demonstration. This has resulted in a leaner, smarter, more focused Texaco Gasification Power System that is now poised to power the '90s - and beyond.

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PAGE 1 OF 3

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PAGE 2 OF 3

TEXACO GASIFICATION TECHNOLOGY SELECTED BY EXXON KOCH

**Texaco Technology Increasingly Attractive to Refiners
for Power Generation**

FOR RELEASE: WEDNESDAY, NOVEMBER 1, 1995.

WHITE PLAINS, N.Y., Nov. 1 - Texaco announced today that Exxon Chemical and Koch Refining Company have each licensed Texaco Gasification Power Systems technology to generate electricity from petroleum coke and other low-value refinery byproducts. These projects can also produce steam and hydrogen.

The worldwide agreement between Texaco's Alternate Energy group and Exxon Chemical provides the basis for Exxon Chemical and other Exxon affiliates to build gasification plants at multiple locations throughout its refining and chemical business. In addition to licensing this proprietary technology to Exxon, Texaco also will provide engineering and technical services. Exxon will designate specific project sites at future dates.

Agreement was reached also between Texaco and Koch Refining Company to utilize the Texaco Gasification Power Systems technology in a project which would gasify petroleum coke to produce electric power, hydrogen and steam. The project is being developed by Koch at its Rosemount, Minnesota refinery.

David C. Crikelair, Vice President of Texaco Inc. and head of Texaco's Alternate Energy group, said, "We are extremely pleased that Exxon Chemical and Koch have selected our gasification technology. The Exxon and Koch projects, along with other projects throughout the world, demonstrate that Texaco's gasification technology is increasingly attractive to refiners and chemical producers who recognize its superior environmental performance, efficiency and operating flexibility."

Four Italian refinery projects also are using the Texaco Gasification Power Systems technology for projects that are under development to produce more than 1,500 megawatts of electricity, plus hydrogen and steam. The superior environmental performance of the technology enables the Italian refiners to use high sulfur fuels, including heavy oil residue, in compliance with stringent European Union environmental standards.

339

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- 2 -

In addition to the Exxon and Koch projects, Texaco is constructing a Texaco Gasification Power Systems facility at its El Dorado, Kansas, refinery. Once operational in 1996, this \$75 million plant will gasify petroleum coke and hazardous wastes to produce 40 megawatts of power and 180,000 pounds per hour of steam. The El Dorado project has established an important precedent by receiving a ruling from the U.S. Environmental Protection Agency that exempts the gasification facility at the refinery from normal hazardous waste permitting requirements because of the technology's proven unique environmental performance.

Emissions from a Texaco Gasification Power Systems facility are far lower than those from conventional power technology utilizing the same feedstocks, and because of its feedstock flexibility and diverse product slate, the Texaco Gasification Process can serve multiple purposes in a refinery thereby enhancing the refinery's ability to vary its crude selection.

Texaco is recognized as the world leader in gasification technology, an environmentally advanced technology that converts hydrocarbon fuels into clean-burning synthesis gas (syngas) to produce electricity, chemical fertilizer, town gas, chemicals and other industrial products. Worldwide, Texaco owned or licensed gasification facilities operating, or under development, have a total syngas production capacity in excess of three billion standard cubic feet per day.

- xxx -

CONTACT: J. Michael Trevino (914) 253-4175

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**EPRI COAL GASIFICATION
REPORTS AVAILABLE**

TEXACO INC.Listing of Coal Gasification Reports Available
From The Electric Power Research Institute

<u>EPRI Reports</u>	<u>Title</u>	<u>Date</u>
GS-6806	Cool Water Coal Gasification Program: Final Report.	August 1990
GS-6819	Texaco Coal Gasification Wastewater Handling and Treatment Pilot Plant. - Volume 1: Performance Summary - Volume 2: Wastewater Sampling & Analysis	August 1990
GS-6165	Technology Assessments for Advanced Fossil Power systems. Bevilacqua-Knight Inc.	December 1989
GS-6470	Technical Assessment of the Indirect-Fired Gas Turbine Power Plant.	September 1989
GS-6485	Eighth Annual EPRI conference on Coal Gasification.	August 1989
GS-6439	Long-Term Leaching Tests with Coal Gasification Slag. Radian Corporation and Tennessee Valley Authority.	July 1989
GS-6415	A Comparison of Steam-Injected Gas Turbine and Combined-Cycle Power Plants Technology Assessment. Jersey Central Power and Lights Company, and Sargent & Lundy.	June 1989
GS-6173	Development of an IGCC Power Plant Simulator. Stone and Webster Eng. Corp.	February 1989
AP-6007-SR	Proceedings: Seventh Annual EPRI Contractor's Conference on Coal Gasification.	October 1988
AP-5931	Cool Water Coal Gasification Program: Fifth Progress Report. Cool Water Coal Gasification Program.	October 1988
AP-5966	Downtime Corrosion in Syngas Coolers of Entrained Slagging Gasifiers, Lockheed Missiles and Space Co.	September 1988
AP-5893	Treatability Testing of KILnGAS and Texaco Coal Gasification Waste Waters, CH ₂ M Hill and Energy and Minerals Research Center, North Dakota.	July 1988

AP-5628	Erosion - Corrosion of Materials In Coal-Water Slurries. Lawrence Berkeley Laboratory.	February 1988
AP-5505	Process Screening Study of Alternative Gas Treating and Sulfur Removal Systems for IGCC Power Plant Applications. SFA Pacific.	December 1987
AP-5342-SR	Proceedings. Sixth Annual EPRI Contractor's Conference on Coal Gasification.	October 1987
AP-5432	Oxygen Plants for Coal Gasification: Experience at the Cool Water GCC Power Plant. BOC Cryoplants.	September 1987
AP-5394	Rheology of coal-Water Slurries at Elevated Temperatures for Gasification. University of North Dakota.	August 1987
AP-5214	Pulverized Coal in Dense Flow. Mountain States Energy.	June 1987
AP-5222	Coal Pretreatment with Carbon Dioxide and Water: Effects on North Dakota Lignite and Utah Coal. Brookhaven National Laboratory.	May 1987
AP-5203	Formulation of Slurries for Slurry-Fed Coal Gasifiers. Brookhaven National Laboratory.	May 1987
AP-5102	Investigation of Sulfur Removal from Low-Pressure Gas. Mittelhauser Corporation.	April 1987
AP-5119	Mutual Solubilities Vapor Pressures for Binary and Ternary Aqueous Systems. Lawrence Berkeley Lab. and U.C. Berkely.	March 1987
AP-5048	Potential Uses for the Slag From the Cool Water Demonstration Plant. Praxis Engineers Inc.	February 1987
AP-5047	Coal Gasification Tests at TVA. Tennessee Valley Authority.	February 1987
AP-5029	Pilot Plant Evaluation of Illinois No. 6 and Pittsburgh No. 8 Coal for the Texaco Coal Gasification Process. Texaco Inc.	January 1987
AP-5005	Pyrolysis of Coal for Production of Low-Sulfur Fuel. Westinghouse Electric Corporation.	January 1987
AP-4905	Low Rank Coal-Water Slurries for Gasification: Phase 2 analytic Studies. University of North Dakota. Energy Research Center.	December 1986

AP-4827	Co Production of Carbon Dioxide and Electricity. Fluor Technology Inc.	November 1986
AP-4849	Investigation of Low-Rank-Coal--Liquid Carbon Dioxide Slurries. Arthur D. Little, Inc.	October 1986
AP-4832	Cool Water Coal Gasification Program: Fourth Annual Progress Report. Cool Water Coal Gasification Program, Bechtel Power Corporation and Radian Corporation.	October 1986
AP-4680	Proceedings: Fifth Annual EPRI Contractor's Conference on Coal Gasification.	July 1986
AP-4657	Coproduction of Peaking Fuel In IGCC Power Plants: A Process Screening Study. Air Products & Chemicals, Inc.	July 1986
AP-4589	Corrosion of Refractories in a Synthetic Coal Slag. Argonne National Labs.	May 1986
AP-4509	Use of Lignite in Texaco Gasification-Based-Combined-Cycle Power Plants, Energy Conversion Systems, Inc.	April 1986
AP-4435	Thermal Upgrading of Low Rank Coal: A Process Screening Study. Bechtel Group, Inc.	March 1986
AP-4452	Laboratory Study of Corrosion of High Temperature Alloys/Coatings in Simulated Medium Btu Gas Atmospheres. Argonne National Laboratory.	February 1986
AP-4406	Evaluation of Coated and Clad Heat Exchangers for Syngas coolers. Volume 1: Evolution of Coating Variability and Weldability. Combustion Engineering. Volume 2: Laboratory Corrosion Study of Coated Low-Alloy Steel Tubes, Lockheed.	February 1986
AP-4344	Corrosion in Quench Systems of Entrained Slagging Gasifiers - A Laboratory Study - ITT Research Institute.	November 1985
AP-4289	Verification Testing of the S-Cubed Entrained - Flow Coal Gasification Code. Los Alamos National Laboratory.	November 1985
AP-4262	Low Rank Coal-Water Slurries for Gasification. University of North Dakota Energy Research Center.	November 1985

AP-4177	Proceedings: Fourth Annual EPRI Contractor's Conference on Coal Gasification.	August 1985
AP-4106	Dynamic Simulation Models for Selective Sulfur Removal in Coal Gasification Systems. Hyprotech Ltd.	July 1985
AP-3876	Cool Water Coal Gasification Program - Third Annual Progress Report. Bechtel Power Corporation Interim Report.	January 1985
AP-3232	Cool Water Coal Gasification Program - Second Annual Progress Report Interim Report.	October 1983
AP-2487	Cool Water Coal Gasification Program - First Annual Progress Report Bechtel Power Corporation Interim Report.	July 1982

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PAGE 1 OF 2**

DOCUMENT NO. 26

**POLK PROJECT COST
ESTIMATE COMPARISON**

Document No. 26

POLK PROJECT COST ESTIMATE COMPARISONS
(\$000)

INTERROGATORY REFERENCE:	(1a)	(1b)	(1c)	(1c)
	Need Hearing 12/91 Estimate	Fall 1993 Estimate	Fall 1994 Estimate	Fall 1995 Estimate
Plant Components				
Plant	\$472,062	\$488,016	\$495,523	\$503,331
DOE Funding	(100,000)	(111,146)	(110,253)	(115,395)
Subtotal without AFUDC & Land	372,062	376,870	385,270	387,936
% Variance from 12/91 Estimate		1.3 %	3.5 %	4.3 %
Land Acquisition & Site Development	0	56,353	64,535	65,835
AFUDC	40,976	56,563	53,513	52,394
TOTAL PROJECT ESTIMATE:	\$413,038	\$489,786	\$503,318	\$506,165

Key Estimate Clarifications

1. The 12/91 Need Hearing estimate (Column 1a) excluded Land Acquisition & Site Development costs in installed cost.
2. The Fall 1993, Fall 1994, and Fall 1995 estimates included Land Acquisition & Site Development costs.
3. Through time, as estimates were developed with more engineering data, component costs were captured more accurately and consistently utilizing the project work break-down structure developed during the preliminary engineering stage of the project in 1992.
4. The Fall 1994 and Fall 1995 estimates (Columns 1c) were prepared as a budget estimates using flow sheets, layout, and equipment details.

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DOCUMENT NO. 27
PAGE 1 OF 2**

DOCUMENT NO. 27

**SUMMARY OF SIGNIFICANT
COST CONTROL ACTIONS**

DOCUMENT NO. 27

SIGNIFICANT COST REDUCTION ACTIONS
(\$ X 1,000)

Listed below are significant cost reduction actions that further reduced costs of construction on Polk Power Station project:

<u>COST REDUCTION ACTIONS</u>	<u>SAVINGS</u>
ACID GAS REMOVAL SYSTEM RATIO CHANGE	(3,630)
CHANGE IN DESIGN BASIS OF THE ACID GAS REMOVAL AND SULFURIC ACID SYSTEMS, FROM 20:1 TO 40:1 HYDROGEN SULFIDE TO CARBONYL SULFIDE RATIO	
REVISION TO OVERALL SITE PLOT PLAN	(1,390)
REVISED OVERALL SITE PLOT PLAN	
DELETE PILING FROM PROJECT	(2,151)
GEOTECHNICAL INVESTIGATION AND FOUNDATION REPORT WHICH ALLOWED FOR DELETION OF PILING	
REDUCE ONSITE COAL STORAGE	(4,044)
REDUCE ONSITE COAL STORAGE FROM 45 DAYS TO 5 DAYS AND ELIMINATE RAIL DELIVERY AND UNLOADING FACILITIES; PROVIDE TRUCK DELIVERY AND UNLOADING	
REPLACE SULFUR PLANT WITH SULFURIC ACID PLANT	(7,437)
REPLACE THE 100% SULFUR PLANT, TAILGAS TREATING UNIT, AND THE 50% CAPACITY SULFURIC ACID PLANT AND REPLACE WITH A 100% CAPACITY TURNKEY SULFURIC ACID PLANT	