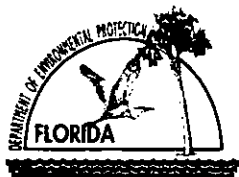


Attachment 1

Air Construction Permit Application



Department of Environmental Protection

Division of Air Resource Management

APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

Air Construction Permit – Use this form to apply for an air construction permit for a proposed project:

- subject to prevention of significant deterioration (PSD) review, nonattainment area (NAA) new source review, or maximum achievable control technology (MACT) review; or
- where the applicant proposes to assume a restriction on the potential emissions of one or more pollutants to escape a federal program requirement such as PSD review, NAA new source review, Title V, or MACT; or
- at an existing federally enforceable state air operation permit (FESOP) or Title V permitted facility.

Air Operation Permit – Use this form to apply for:

- an initial federally enforceable state air operation permit (FESOP); or
- an initial/revised/renewal Title V air operation permit.

Air Construction Permit & Revised/Renewal Title V Air Operation Permit (Concurrent Processing Option)
– Use this form to apply for both an air construction permit and a revised or renewal Title V air operation permit incorporating the proposed project.

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: Tampa Electric Company	
2. Site Name: Polk Power Station	
3. Facility Identification Number: 1050233	
4. Facility Location...: Street Address or Other Locator: 9995 State Route 37 South City: Mulberry County: Polk Zip Code: 33860-0775	
5. Relocatable Facility? <input type="checkbox"/> Yes <input checked="" type="checkbox"/> No	6. Existing Title V Permitted Facility? <input checked="" type="checkbox"/> Yes <input type="checkbox"/> No

Application Contact

1. Application Contact Name: Raiza Calderon, Engineer —Air Programs	
2. Application Contact Mailing Address... Organization/Firm: Tampa Electric Company Street Address: P.O. Box 111 City: Tampa State: FL Zip Code: 33601	
3. Application Contact Telephone Numbers... Telephone: (813) 228-4369 ext. Fax: (813) 228-1308	
4. Application Contact Email Address: <u>rcalderon@tecoenergy.com</u>	

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	3/2/06
2. Project Number(s):	1050233-019-AC
3. PSD Number (if applicable):	
4. Siting Number (if applicable):	

APPLICATION INFORMATION

Purpose of Application

This application for air permit is submitted to obtain: (Check one)

Air Construction Permit

Air construction permit.

Air Operation Permit

- Initial Title V air operation permit.
- Title V air operation permit revision.
- Title V air operation permit renewal.
- Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is required.
- Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is not required.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit (Concurrent Processing)

- Air construction permit and Title V permit revision, incorporating the proposed project.
- Air construction permit and Title V permit renewal, incorporating the proposed project.

Note: By checking one of the above two boxes, you, the applicant, are requesting concurrent processing pursuant to Rule 62-213.405, F.A.C. In such case, you must also check the following box:

- I hereby request that the department waive the processing time requirements of the air construction permit to accommodate the processing time frames of the Title V air operation permit.

Application Comment

Tampa Electric Company (TEC) requests authorization to conduct a test burn of petroleum coke at its Polk Power Station (PPS) integrated gasification combined-cycle (IGCC) facility located on State Road 37 South in Mulberry, Polk County, Florida.

The PPS Solid Fuel Gasification System (EU ID 006) is presently authorized to process coal or coal/petroleum coke blends containing a maximum of 60.0 percent petroleum coke by weight by FINAL Permit No.: 1050233-016-AV. TEC requests authorization to conduct a test burn of up to 100 percent petroleum coke, including a flux, with a maximum sulfur content of 6.0 percent by weight.

Use of 100 percent petroleum coke will potentially affect emissions from the combined-cycle unit (EU ID 001), the sulfuric acid plant (EU ID 004), and the solid fuel gasification system (EU 006). The purpose of the test burn is to evaluate the feasibility of gasifying 100 percent petroleum coke and to document that use of 100 percent petroleum coke will not result in a major modification to the PPS under the Prevention of Significant Deterioration (PSD) regulatory program.

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Proc. Fee
001	260 MW Combined-Cycle Combustion Turbine	ACM1	N/A
004	Sulfuric Acid Plant	ACM1	N/A
006	Solid Fuel Gasification System	ACM1	N/A

Application Processing Fee

Check one: Attached - Amount: \$ _____ Not Applicable

A permit processing fee is not required for a modification to a Title V source pursuant to Rule 62-4.050(4)(a)2., F.A.C.

APPLICATION INFORMATION

Owner/Authorized Representative Statement

Complete if applying for an air construction permit or an initial FESOP.

1. Owner/Authorized Representative Name: Mark J. Hornick, General Manager
2. Owner/Authorized Representative Mailing Address... Organization/Firm: Tampa Electric Company Street Address: P.O. Box 111 City: Tampa State: FL Zip Code: 33601-0111
3. Owner/Authorized Representative Telephone Numbers... Telephone: (813) 288-1111 ext. 39988 Fax: (863) 428-5927
4. Owner/Authorized Representative Email Address: mjhornick@tecoenergy.com
5. Owner/Authorized Representative Statement: <i>I, the undersigned, am the owner or authorized representative of the facility addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other requirements identified in this application to which the facility is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit.</i>  Signature  Date

APPLICATION INFORMATION


Application Responsible Official Certification N/A

Complete if applying for an initial/revised/renewal Title V permit or concurrent processing of an air construction permit and a revised/renewal Title V permit. If there are multiple responsible officials, the "application responsible official" need not be the "primary responsible official."

1. Application Responsible Official Name:
2. Application Responsible Official Qualification (Check one or more of the following options, as applicable): <input type="checkbox"/> For a corporation, the president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit under Chapter 62-213, F.A.C. <input type="checkbox"/> For a partnership or sole proprietorship, a general partner or the proprietor, respectively. <input type="checkbox"/> For a municipality, county, state, federal, or other public agency, either a principal executive officer or ranking elected official. <input type="checkbox"/> The designated representative at an Acid Rain source.
3. Application Responsible Official Mailing Address... Organization/Firm: Street Address: City: State: Zip Code:
4. Application Responsible Official Telephone Numbers... Telephone: ext. Fax:
5. Application Responsible Official Email Address:
6. Application Responsible Official Certification: <i>I, the undersigned, am a responsible official of the Title V source addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other applicable requirements identified in this application to which the Title V source is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit. Finally, I certify that the facility and each emissions unit are in compliance with all applicable requirements to which they are subject, except as identified in compliance plan(s) submitted with this application.</i> _____ Signature _____ Date

APPLICATION INFORMATION

Professional Engineer Certification

1. Professional Engineer Name: Thomas W. Davis Registration Number: 36777
2. Professional Engineer Mailing Address... Organization/Firm: Environmental Consulting & Technology, Inc. Street Address: 3701 Northwest 98th Street City: Gainesville State: FL Zip Code: 32606
3. Professional Engineer Telephone Numbers... Telephone: (352) 332-0444 ext. Fax: (352) 332-6722
4. Professional Engineer Email Address: tdavis@ectinc.com
5. Professional Engineer Statement: <i>I, the undersigned, hereby certify, except as particularly noted herein*, that:</i> <i>(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this application for air permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and</i> <i>(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.</i> <i>(3) If the purpose of this application is to obtain a Title V air operation permit (check here <input type="checkbox"/>, if so), I further certify that each emissions unit described in this application for air permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance plan and schedule is submitted with this application.</i> <i>(4) If the purpose of this application is to obtain an air construction permit (check here <input checked="" type="checkbox"/>, if so) or concurrently process and obtain an air construction permit and a Title V air operation permit revision or renewal for one or more proposed new or modified emissions units (check here <input type="checkbox"/>, if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.</i> <i>(5) If the purpose of this application is to obtain an initial air operation permit or operation permit revision or renewal for one or more newly constructed or modified emissions units (check here <input type="checkbox"/>, if so); I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.</i>  Signature: _____ Date: <u>2/23/06</u>

* Attach any exception to certification statement.

APPLICATION INFORMATION

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates...		2. Facility Latitude/Longitude...	
Zone 17	East (km) 402.45 North (km) 3,067.35	Latitude (DD/MM/SS) 27/43/43 Longitude (DD/MM/SS) 81/59/23	
3. Governmental Facility Code:	4. Facility Status Code:	5. Facility Major Group SIC Code:	6. Facility SIC(s):
0	A	49	4911
7. Facility Comment :			

Facility Contact

1. Facility Contact Name: Mike Perkins, Environmental Coordinator
2. Facility Contact Mailing Address... Organization/Firm: Tampa Electric Company Street Address: P.O. Box 111 City: Tampa State: FL Zip Code: 33601-0111
3. Facility Contact Telephone Numbers: Telephone: (813) 228-1111 ext. 39109 Fax: (863) 428-5927
4. Facility Contact Email Address: msperkins@tecoenergy.com

Facility Primary Responsible Official N/A

Complete if an "application responsible official" is identified in Section I. that is not the facility "primary responsible official."

1. Facility Primary Responsible Official Name:
2. Facility Primary Responsible Official Mailing Address... Organization/Firm: Street Address: City: State: Zip Code:
3. Facility Primary Responsible Official Telephone Numbers... Telephone: () - ext. Fax: () -
4. Facility Primary Responsible Official Email Address:

Facility Regulatory Classifications

Check all that would apply *following* completion of all projects and implementation of all other changes proposed in this application for air permit. Refer to instructions to distinguish between a “major source” and a “synthetic minor source.”

1. <input type="checkbox"/> Small Business Stationary Source	<input type="checkbox"/> Unknown
2. <input type="checkbox"/> Synthetic Non-Title V Source	
3. <input checked="" type="checkbox"/> Title V Source	
4. <input checked="" type="checkbox"/> Major Source of Air Pollutants, Other than Hazardous Air Pollutants (HAPs)	
5. <input type="checkbox"/> Synthetic Minor Source of Air Pollutants, Other than HAPs	
6. <input type="checkbox"/> Major Source of Hazardous Air Pollutants (HAPs)	
7. <input checked="" type="checkbox"/> Synthetic Minor Source of HAPs	
8. <input checked="" type="checkbox"/> One or More Emissions Units Subject to NSPS (40 CFR Part 60)	
9. <input type="checkbox"/> One or More Emissions Units Subject to Emission Guidelines (40 CFR Part 60)	
10. <input type="checkbox"/> One or More Emissions Units Subject to NESHAP (40 CFR Part 61 or Part 63)	
11. <input type="checkbox"/> Title V Source Solely by EPA Designation (40 CFR 70.3(a)(5))	
12. Facility Regulatory Classifications Comment:	

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
NOX	A	N
SO2	A	N
CO	A	N
PM10	A	N
PM	A	N
SAM	A	N
VOC	A	N
PB	B	N
H114 (Mercury Compounds)	B	N
H015 (Arsenic Compounds)	B	N
H021 (Beryllium Compounds)	B	N

B. EMISSIONS CAPS

Facility-Wide or Multi-Unit Emissions Caps N/A

1. Pollutant Subject to Emissions Cap	2. Facility Wide Cap [Y or N]? (all units)	3. Emissions Unit ID No.s Under Cap (if not all units)	4. Hourly Cap (lb/hr)	5. Annual Cap (ton/yr)	6. Basis for Emissions Cap

7. Facility-Wide or Multi-Unit Emissions Cap Comment:

C. FACILITY ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

<p>1. Facility Plot Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)</p> <p><input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Previously Submitted, Date: <u>April 2004</u></p>
<p>2. Process Flow Diagram(s): (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)</p> <p><input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Previously Submitted, Date: <u>April 2004</u></p>
<p>3. Precautions to Prevent Emissions of Unconfined Particulate Matter: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)</p> <p><input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Previously Submitted, Date: <u>April 2004</u></p>

Additional Requirements for Air Construction Permit Applications

<p>1. Area Map Showing Facility Location:</p> <p><input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Not Applicable (existing permitted facility)</p>
<p>2. Description of Proposed Construction or Modification:</p> <p><input type="checkbox"/> Attached, Document ID: See prior TEC test burn request submittals.</p>
<p>3. Rule Applicability Analysis:</p> <p><input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Not Applicable (No change in applicable requirements)</p>
<p>4. List of Exempt Emissions Units (Rule 62-210.300(3)(a) or (b)1., F.A.C.):</p> <p><input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Not Applicable (no exempt units at facility)</p>
<p>5. Fugitive Emissions Identification (Rule 62-212.400(2), F.A.C.):</p> <p><input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Not Applicable</p>
<p>6. Preconstruction Air Quality Monitoring and Analysis (Rule 62-212.400(5)(f), F.A.C.):</p> <p><input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Not Applicable</p>
<p>7. Ambient Impact Analysis (Rule 62-212.400(5)(d), F.A.C.):</p> <p><input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Not Applicable</p>
<p>8. Air Quality Impact since 1977 (Rule 62-212.400(5)(h)5., F.A.C.):</p> <p><input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Not Applicable</p>
<p>9. Additional Impact Analyses (Rules 62-212.400(5)(e)1. and 62-212.500(4)(e), F.A.C.):</p> <p><input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Not Applicable</p>
<p>10. Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.):</p> <p><input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Not Applicable</p>

Additional Requirements for FESOP Applications N/A

1. List of Exempt Emissions Units (Rule 62-210.300(3)(a) or (b)1., F.A.C.): <input type="checkbox"/> Attached, Document ID: <input type="checkbox"/> Not Applicable (no exempt units at facility)
--

Additional Requirements for Title V Air Operation Permit Applications N/A

1. List of Insignificant Activities (Required for initial/renewal applications only): <input type="checkbox"/> Attached, Document ID: <input type="checkbox"/> Not Applicable (revision application)
2. Identification of Applicable Requirements (Required for initial/renewal applications, and for revision applications if this information would be changed as a result of the revision being sought): <input type="checkbox"/> Attached, Document ID: <input type="checkbox"/> Not Applicable (revision application with no change in applicable requirements)
3. Compliance Report and Plan (Required for all initial/revision/renewal applications): <input type="checkbox"/> Attached, Document ID: Note: A compliance plan must be submitted for each emissions unit that is not in compliance with all applicable requirements at the time of application and/or at any time during application processing. The department must be notified of any changes in compliance status during application processing.
4. List of Equipment/Activities Regulated under Title VI (If applicable, required for initial/renewal applications only): <input type="checkbox"/> Attached, Document ID: <input type="checkbox"/> Equipment/Activities On site but Not Required to be Individually Listed <input type="checkbox"/> Not Applicable
5. Verification of Risk Management Plan Submission to EPA (If applicable, required for initial/renewal applications only) : <input type="checkbox"/> Attached, Document ID: <input type="checkbox"/> Not Applicable
6. Requested Changes to Current Title V Air Operation Permit: <input type="checkbox"/> Attached, Document ID: <input type="checkbox"/> Not Applicable

Additional Requirements Comment

--

EMISSIONS UNIT INFORMATION

Section [1] of [3]

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section:
Nominal 260 MW combined-cycle combustion turbine

3. Emissions Unit Identification Number: **011**

4. Emissions Unit Status Code: A	5. Commence Construction Date: N/A	6. Initial Startup Date: N/A	7. Emissions Unit Major Group SIC Code: 49	8. Acid Rain Unit? <input checked="" type="checkbox"/> Yes <input type="checkbox"/> No
--	--	--	--	--

9. Package Unit:
 Manufacturer: **General Electric** Model Number: **7F**

10. Generator Nameplate Rating: **260 MW**

11. Emissions Unit Comment:

EMISSIONS UNIT INFORMATION

Section [1] of [3]

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description:

NOx

Nitrogen diluent injection and syngas water saturation (syngas)

Water injection (distillate fuel oil)

2. Control Device or Method Code(s): **028 (water injection)**

EMISSIONS UNIT INFORMATION

Section [1] of [3]

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:	N/A
2. Maximum Production Rate:	N/A
3. Maximum Heat Input Rate:	1,765 million Btu/hr
4. Maximum Incineration Rate:	pounds/hr N/A tons/day
5. Requested Maximum Operating Schedule:	24 hours/day 7 days/week 52 weeks/year 8,760 hours/year
6. Operating Capacity/Schedule Comment:	Maximum heat rate is 1,765 MMBtu/hr (distillate fuel oil) and 1,755 MMBtu/hr (syngas). Both rates are on a monthly average basis.

EMISSIONS UNIT INFORMATION

Section [1] of [3]

C. EMISSION POINT (STACK/VENT) INFORMATION
 (Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: CT-01		2. Emission Point Type Code: 1	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: N/A			
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: N/A			
5. Discharge Type Code: V	6. Stack Height: 150 feet	7. Exit Diameter: 19.0 feet	
8. Exit Temperature: 340 °F	9. Actual Volumetric Flow Rate: 1,290,000 acfm	10. Water Vapor: % N/A	
11. Maximum Dry Standard Flow Rate: dscfm N/A		12. Nonstack Emission Point Height: feet N/A	
13. Emission Point UTM Coordinates... N/A Zone: East (km): North (km):		14. Emission Point Latitude/Longitude... N/A Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
15. Emission Point Comment:			

EMISSIONS UNIT INFORMATION

Section [1] of [3]

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type): Combustion turbine fired with syngas.		
2. Source Classification Code (SCC): 1-01-019-01		3. SCC Units: Million Cubic Feet Burned
4. Maximum Hourly Rate: 9.24	5. Maximum Annual Rate: 80,914.7	6. Estimated Annual Activity Factor: N/A
7. Maximum % Sulfur: 0.07	8. Maximum % Ash: N/A	9. Million Btu per SCC Unit: 190
10. Segment Comment: Maximum hourly rate (Field 4), maximum annual rate (Field 5), and million Btu/SCC unit (Field 9) based on average fuel heat content of 190 Btu/cubic foot.		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): Combustion turbine fired with distillate fuel oil.		
2. Source Classification Code (SCC): 2-01-001-01		3. SCC Units: Thousand Gallons Burned
4. Maximum Hourly Rate: 12.71	5. Maximum Annual Rate: 11,131.32	6. Estimated Annual Activity Factor: N/A
7. Maximum % Sulfur: .05	8. Maximum % Ash: .01	9. Million Btu per SCC Unit: 138.9
10. Segment Comment: Maximum hourly rate (Field 4), maximum annual rate (Field 5), and million Btu/SCC unit (Field 9) based on average fuel heat content of 138,900 Btu/gal. Maximum annual rate (Field 5) based on maximum 10 percent capacity factor for distillate fuel oil firing.		

EMISSIONS UNIT INFORMATION

Section [1] of [3]

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
1 - CO			EL
2 - VOC			EL
3 - NOX	028		EL
4 - PM/PM10			EL
5 - SO2			EL
6 - PB			EL
7 - SAM			EL
8 - H015 (arsenic)			EL
9 - H021 (beryllium)			EL
10 - H114 (mercury)			EL

**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
 POTENTIAL/ESTIMATED FUGITIVE EMISSIONS**

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted:		2. Total Percent Efficiency of Control:	
3. Potential Emissions: lb/hour tons/year		4. Synthetically Limited? <input type="checkbox"/> Yes <input type="checkbox"/> No	
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year			
6. Emission Factor: Reference:		7. Emissions Method Code:	
8. Calculation of Emissions:			
9. Pollutant Potential/Estimated Fugitive Emissions Comment: TEC is not requesting any revisions to currently authorized emission standards as specified in FINAL Title V Permit No. 1050233-016-AV. The information requested by Section F1 regarding potential (allowable) emissions for EU ID 001 can be found in FINAL Title V Permit No. V1050233-016-AV.			

**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
 ALLOWABLE EMISSIONS**

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method): TEC is not requesting any revisions to currently authorized emission standards as specified in FINAL Title V Permit No. 1050233-016-AV. The information requested by Section F2 regarding allowable emissions for EU ID 001 can be found in FINAL Title V Permit No. 1050233-016-AV.	

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation **1** of **2**

1. Visible Emissions Subtype: VE10	2. Basis for Allowable Opacity: <input checked="" type="checkbox"/> Rule <input type="checkbox"/> Other
3. Allowable Opacity: Normal Conditions: 10 % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: EPA Reference Method 9 annually.	
5. Visible Emissions Comment: Limit applicable for syngas-firing.	

Visible Emissions Limitation: Visible Emissions Limitation **2** of **2**

1. Visible Emissions Subtype: VE20	2. Basis for Allowable Opacity: <input checked="" type="checkbox"/> Rule <input type="checkbox"/> Other
3. Allowable Opacity: Normal Conditions: 20 % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
6. Method of Compliance: EPA Reference Method 9 annually.	
7. Visible Emissions Comment: Limit applicable for distillate fuel oil-firing.	

EMISSIONS UNIT INFORMATION

Section [1] of [3]

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor ___ of ___

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	<input type="checkbox"/> Rule <input type="checkbox"/> Other
4. Monitor Information: Manufacturer:	Serial Number:
Model Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: Information regarding EU ID 001 CEMS remains unchanged from the data previously provided to the Department.	

Continuous Monitoring System: Continuous Monitor ___ of ___

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	<input type="checkbox"/> Rule <input type="checkbox"/> Other
4. Monitor Information: Manufacturer:	Serial Number:
Model Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

EMISSIONS UNIT INFORMATION

Section [1] of [3]

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) <input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Previously Submitted, Date: April 2004
2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) <input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Previously Submitted, Date: April 2004
3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) <input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Previously Submitted, Date: April 2004
4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Previously Submitted, Date: _____ <input checked="" type="checkbox"/> Not Applicable (construction application)
5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Previously Submitted, Date _____ <input checked="" type="checkbox"/> Not Applicable
6. Compliance Demonstration Reports/Records <input type="checkbox"/> Attached, Document ID: _____ Test Date(s)/Pollutant(s) Tested: _____ <input type="checkbox"/> Previously Submitted, Date: _____ Test Date(s)/Pollutant(s) Tested: _____ <input type="checkbox"/> To be Submitted, Date (if known): _____ Test Date(s)/Pollutant(s) Tested: _____ <input checked="" type="checkbox"/> Not Applicable Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7. Other Information Required by Rule or Statute <input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Not Applicable

EMISSIONS UNIT INFORMATION

Section [1] of [3]

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)) <input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Not Applicable
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.) <input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Not Applicable
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) <input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Not Applicable

Additional Requirements for Title V Air Operation Permit Applications N/A

1. Identification of Applicable Requirements <input type="checkbox"/> Attached, Document ID: _____
2. Compliance Assurance Monitoring <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Not Applicable
3. Alternative Methods of Operation <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Not Applicable
4. Alternative Modes of Operation (Emissions Trading) <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Not Applicable
5. Acid Rain Part Application <input type="checkbox"/> Certificate of Representation (EPA Form No. 7610-1) <input type="checkbox"/> Copy Attached, Document ID: _____ <input type="checkbox"/> Acid Rain Part (Form No. 62-210.900(1)(a)) <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Previously Submitted, Date: _____ <input type="checkbox"/> Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Previously Submitted, Date: _____ <input type="checkbox"/> New Unit Exemption (Form No. 62-210.900(1)(a)2.) <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Previously Submitted, Date: _____ <input type="checkbox"/> Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Previously Submitted, Date: _____ <input type="checkbox"/> Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Previously Submitted, Date: _____ <input type="checkbox"/> Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Previously Submitted, Date: _____ <input type="checkbox"/> Not Applicable

EMISSIONS UNIT INFORMATION

Section [1] of [3]

Additional Requirements Comment

EMISSIONS UNIT INFORMATION

Section [2] of [3]

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

3. Description of Emissions Unit Addressed in this Section:
Sulfuric Acid Plant

3. Emissions Unit Identification Number: **004**

4. Emissions Unit Status Code: A	5. Commence Construction Date: N/A	6. Initial Startup Date: N/A	7. Emissions Unit Major Group SIC Code: 49	8. Acid Rain Unit? <input type="checkbox"/> Yes <input checked="" type="checkbox"/> No
--	--	--	--	--

9. Package Unit:
Manufacturer: **N/A** Model Number: **N/A**

10. Generator Nameplate Rating: **N/A**

12. Emissions Unit Comment:

EMISSIONS UNIT INFORMATION

Section [2] of [3]

Emissions Unit Control Equipment

2. Control Equipment/Method(s) Description:

SO₂

Double contact process

H₂SO₄ Mist

Mist eliminators

2. Control Device or Method Code(s): **044 (double contact process), 152 (mist eliminators)**

EMISSIONS UNIT INFORMATION

Section [2] of [3]

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:	N/A				
2. Maximum Production Rate:	77,640 tons/year of 100 percent sulfuric acid				
3. Maximum Heat Input Rate:	N/A million Btu/hr				
4. Maximum Incineration Rate:	pounds/hr N/A tons/day				
5. Requested Maximum Operating Schedule:	<table><tr><td>24 hours/day</td><td>7 days/week</td></tr><tr><td>52 weeks/year</td><td>8,760 hours/year</td></tr></table>	24 hours/day	7 days/week	52 weeks/year	8,760 hours/year
24 hours/day	7 days/week				
52 weeks/year	8,760 hours/year				
6. Operating Capacity/Schedule Comment:					

EMISSIONS UNIT INFORMATION

Section [2] of [3]

C. EMISSION POINT (STACK/VENT) INFORMATION

(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: AP-01		2. Emission Point Type Code: 1	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: N/A			
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: N/A			
5. Discharge Type Code: V	6. Stack Height: 199 feet	7. Exit Diameter: 2.5 feet	
8. Exit Temperature: 180 °F	9. Actual Volumetric Flow Rate: 17,660 acfm	10. Water Vapor: % N/A	
11. Maximum Dry Standard Flow Rate: dscfm N/A		12. Nonstack Emission Point Height: feet N/A	
13. Emission Point UTM Coordinates... N/A Zone: East (km): North (km):		14. Emission Point Latitude/Longitude... N/A Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
15. Emission Point Comment: Two other emission points exist within the sulfuric acid plant. The propane-fired H₂S-to-SO₂ conversion furnace vents directly to the atmosphere during acid plant warmup - 15 MMBtu/hr maximum heat input during warmup; vented to atmosphere only when process gas is not being treated. Also, a propane-fired SO₂-to-SO₃ converter preheater (9 MMBtu/hr heat input) produces a non-contact exhaust stream that vents directly to the atmosphere.			

EMISSIONS UNIT INFORMATION

Section [2] of [3]

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type): Sulfuric acid production.		
2. Source Classification Code (SCC): 3-01-023-99		3. SCC Units: Tons produced or manufactured
4. Maximum Hourly Rate: 8.90	5. Maximum Annual Rate: 77,640.0	6. Estimated Annual Activity Factor: N/A
7. Maximum % Sulfur: N/A	8. Maximum % Ash: N/A	9. Million Btu per SCC Unit: N/A
10. Segment Comment:		

Segment Description and Rate: Segment of

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):		3. SCC Units:
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

EMISSIONS UNIT INFORMATION

Section [2] of [3]

E. EMISSIONS UNIT POLLUTANTS**List of Pollutants Emitted by Emissions Unit**

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
1 - SO2	044		EL
2 - SAM	152		EL
3 - NOX			NS
4 - PM/PM10			NS
5 - CO			NS

**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL/ESTIMATED FUGITIVE EMISSIONS**

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted:		2. Total Percent Efficiency of Control:	
3. Potential Emissions: lb/hour tons/year		4. Synthetically Limited? <input type="checkbox"/> Yes <input type="checkbox"/> No	
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year			
6. Emission Factor: Reference:		7. Emissions Method Code:	
8. Calculation of Emissions:			
9. Pollutant Potential/Estimated Fugitive Emissions Comment: TEC is not requesting any revisions to currently authorized emission standards as specified in FINAL Title V Permit No. 1050233-016-AV. The information requested by Section F1 regarding potential (allowable) emissions for EU ID 004 can be found in FINAL Title V Permit No. V1050233-016-AV.			

**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
 ALLOWABLE EMISSIONS**

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	5. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method): TEC is not requesting any revisions to currently authorized emission standards as specified in FINAL Title V Permit No. 1050233-016-AV. The information requested by Section F2 regarding allowable emissions for EU ID 004 can be found in FINAL Title V Permit No. 1050233-016-AV.	

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: VE10	2. Basis for Allowable Opacity: <input checked="" type="checkbox"/> Rule <input type="checkbox"/> Other
3. Allowable Opacity: Normal Conditions: 10 % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
8. Method of Compliance: EPA Reference Method 9 annually.	
9. Visible Emissions Comment: Rule 62-296.402(2)(a), F.A.C.	

Visible Emissions Limitation: Visible Emissions Limitation of

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: <input type="checkbox"/> Rule <input type="checkbox"/> Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
10. Method of Compliance:	
11. Visible Emissions Comment:	

EMISSIONS UNIT INFORMATION

Section [2] of [3]

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor ___ of ___ N/A

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	<input type="checkbox"/> Rule <input type="checkbox"/> Other
4. Monitor Information: Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor ___ of ___

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	<input type="checkbox"/> Rule <input type="checkbox"/> Other
4. Monitor Information: Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

EMISSIONS UNIT INFORMATION

Section [2] of [3]

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) <input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Previously Submitted, Date: April 2004
2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) <input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Previously Submitted, Date: April 2004
3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) <input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Previously Submitted, Date: April 2004
4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Previously Submitted, Date: _____ <input checked="" type="checkbox"/> Not Applicable (construction application)
5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Previously Submitted, Date: _____ <input checked="" type="checkbox"/> Not Applicable
6. Compliance Demonstration Reports/Records <input type="checkbox"/> Attached, Document ID: _____ Test Date(s)/Pollutant(s) Tested: _____ <input type="checkbox"/> Previously Submitted, Date: _____ Test Date(s)/Pollutant(s) Tested: _____ <input type="checkbox"/> To be Submitted, Date (if known): _____ Test Date(s)/Pollutant(s) Tested: _____ <input checked="" type="checkbox"/> Not Applicable Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7. Other Information Required by Rule or Statute <input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Not Applicable

EMISSIONS UNIT INFORMATION

Section [2] of [3]

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)) <input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Not Applicable
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.) <input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Not Applicable
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) <input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Not Applicable

Additional Requirements for Title V Air Operation Permit Applications N/A

1. Identification of Applicable Requirements <input type="checkbox"/> Attached, Document ID: _____
2. Compliance Assurance Monitoring <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Not Applicable
3. Alternative Methods of Operation <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Not Applicable
4. Alternative Modes of Operation (Emissions Trading) <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Not Applicable
5. Acid Rain Part Application <input type="checkbox"/> Certificate of Representation (EPA Form No. 7610-1) <input type="checkbox"/> Copy Attached, Document ID: _____ <input type="checkbox"/> Acid Rain Part (Form No. 62-210.900(1)(a)) <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Previously Submitted, Date: _____ <input type="checkbox"/> Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Previously Submitted, Date: _____ <input type="checkbox"/> New Unit Exemption (Form No. 62-210.900(1)(a)2.) <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Previously Submitted, Date: _____ <input type="checkbox"/> Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Previously Submitted, Date: _____ <input type="checkbox"/> Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Previously Submitted, Date: _____ <input type="checkbox"/> Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Previously Submitted, Date: _____ <input type="checkbox"/> Not Applicable

EMISSIONS UNIT INFORMATION

Section [2] of [3]

Additional Requirements Comment

EMISSIONS UNIT INFORMATION

Section [3] of [3]

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

4. Description of Emissions Unit Addressed in this Section:
Solid Fuel Gasification System

3. Emissions Unit Identification Number: **006**

4. Emissions Unit Status Code: A	5. Commence Construction Date: N/A	6. Initial Startup Date: N/A	7. Emissions Unit Major Group SIC Code: 49	8. Acid Rain Unit? <input type="checkbox"/> Yes <input checked="" type="checkbox"/> No
--	--	--	--	--

9. Package Unit:
 Manufacturer: **N/A** Model Number: **N/A**

10. Generator Nameplate Rating: **N/A**

13. Emissions Unit Comment:
System converts solid fuel (coal or coal/petroleum coke blends) into syngas for the purpose of electric generation. This application request authorization to conduct a test burn of up to 100 percent by weight petroleum coke with a flux.

EMISSIONS UNIT INFORMATION

Section [3] of [3]

Emissions Unit Control Equipment

3. Control Equipment/Method(s) Description:

Flare (during emergencies and startup/shutdown).

2. Control Device or Method Code(s): **023 (flare)**

EMISSIONS UNIT INFORMATION

Section [3] of [3]

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:	2,325 ton/day on a dry basis
2. Maximum Production Rate:	N/A
3. Maximum Heat Input Rate:	N/A million Btu/hr
4. Maximum Incineration Rate:	pounds/hr N/A tons/day
5. Requested Maximum Operating Schedule:	24 hours/day 7 days/week 52 weeks/year 8,760 hours/year
6. Operating Capacity/Schedule Comment:	This application request authorization to conduct a test burn of up to 100 percent by weight petroleum coke with a flux.

EMISSIONS UNIT INFORMATION

Section [3] of [3]

C. EMISSION POINT (STACK/VENT) INFORMATION
 (Optional for unregulated emissions units.)

Emission Point Description and Type N/A

1. Identification of Point on Plot Plan or Flow Diagram:		2. Emission Point Type Code:	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:			
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:			
5. Discharge Type Code:	6. Stack Height: feet	7. Exit Diameter: feet	
8. Exit Temperature: °F	9. Actual Volumetric Flow Rate: acfm	10. Water Vapor: %	
11. Maximum Dry Standard Flow Rate: dscfm		12. Nonstack Emission Point Height: feet	
13. Emission Point UTM Coordinates... Zone: East (km): North (km):		14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
15. Emission Point Comment:			

EMISSIONS UNIT INFORMATION

Section [3] of [3]

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type): Solid fuel gasification (coal, petroleum coke, and coal/petroleum blends)		
2. Source Classification Code (SCC): 3-01-999-99		3. SCC Units: Tons processed
4. Maximum Hourly Rate: N/A	5. Maximum Annual Rate: 952,020	6. Estimated Annual Activity Factor: N/A
7. Maximum % Sulfur: N/A	8. Maximum % Ash: N/A	9. Million Btu per SCC Unit: N/A
10. Segment Comment: Maximum daily rate will not exceed 2,325 tons on a dry basis.		

Segment Description and Rate: Segment of

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):		3. SCC Units:
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

EMISSIONS UNIT INFORMATION

Section [3] of [3]

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit N/A

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code

**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
 POTENTIAL/ESTIMATED FUGITIVE EMISSIONS**

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions N/A

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted:		2. Total Percent Efficiency of Control:	
3. Potential Emissions: lb/hour tons/year		4. Synthetically Limited? <input type="checkbox"/> Yes <input type="checkbox"/> No	
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year			
6. Emission Factor: Reference:		7. Emissions Method Code:	
8. Calculation of Emissions:			
9. Pollutant Potential/Estimated Fugitive Emissions Comment:			

**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
 ALLOWABLE EMISSIONS**

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions of **N/A**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	6. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

EMISSIONS UNIT INFORMATION

Section [3] of [3]

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation of N/A

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: <input type="checkbox"/> Rule <input type="checkbox"/> Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
12. Method of Compliance:	
13. Visible Emissions Comment:	

Visible Emissions Limitation: Visible Emissions Limitation of

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: <input type="checkbox"/> Rule <input type="checkbox"/> Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
14. Method of Compliance:	
15. Visible Emissions Comment:	

EMISSIONS UNIT INFORMATION

Section [3] of [3]

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor ___ of ___ N/A

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	<input type="checkbox"/> Rule <input type="checkbox"/> Other
4. Monitor Information: Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor ___ of ___

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	<input type="checkbox"/> Rule <input type="checkbox"/> Other
4. Monitor Information: Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

EMISSIONS UNIT INFORMATION

Section [3] of [3]

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) <input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Previously Submitted, Date: April 2004
2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) <input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Previously Submitted, Date: April 2004
3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) <input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Previously Submitted, Date: April 2004
4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Previously Submitted, Date: _____ <input checked="" type="checkbox"/> Not Applicable (construction application)
5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Previously Submitted, Date _____ <input checked="" type="checkbox"/> Not Applicable
6. Compliance Demonstration Reports/Records <input type="checkbox"/> Attached, Document ID: _____ Test Date(s)/Pollutant(s) Tested: _____ <input type="checkbox"/> Previously Submitted, Date: _____ Test Date(s)/Pollutant(s) Tested: _____ <input type="checkbox"/> To be Submitted, Date (if known): _____ Test Date(s)/Pollutant(s) Tested: _____ <input checked="" type="checkbox"/> Not Applicable Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7. Other Information Required by Rule or Statute <input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Not Applicable

EMISSIONS UNIT INFORMATION

Section [3] of [3]

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)) <input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Not Applicable
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.) <input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Not Applicable
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) <input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Not Applicable

Additional Requirements for Title V Air Operation Permit Applications N/A

1. Identification of Applicable Requirements <input type="checkbox"/> Attached, Document ID: _____
2. Compliance Assurance Monitoring <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Not Applicable
3. Alternative Methods of Operation <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Not Applicable
4. Alternative Modes of Operation (Emissions Trading) <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Not Applicable
5. Acid Rain Part Application <input type="checkbox"/> Certificate of Representation (EPA Form No. 7610-1) <input type="checkbox"/> Copy Attached, Document ID: _____ <input type="checkbox"/> Acid Rain Part (Form No. 62-210.900(1)(a)) <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Previously Submitted, Date: _____ <input type="checkbox"/> Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Previously Submitted, Date: _____ <input type="checkbox"/> New Unit Exemption (Form No. 62-210.900(1)(a)2.) <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Previously Submitted, Date: _____ <input type="checkbox"/> Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Previously Submitted, Date: _____ <input type="checkbox"/> Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Previously Submitted, Date: _____ <input type="checkbox"/> Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Previously Submitted, Date: _____ <input type="checkbox"/> Not Applicable

EMISSIONS UNIT INFORMATION

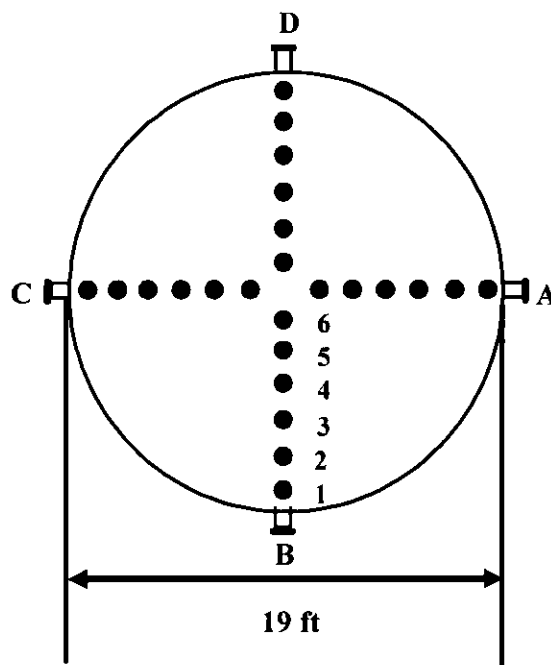
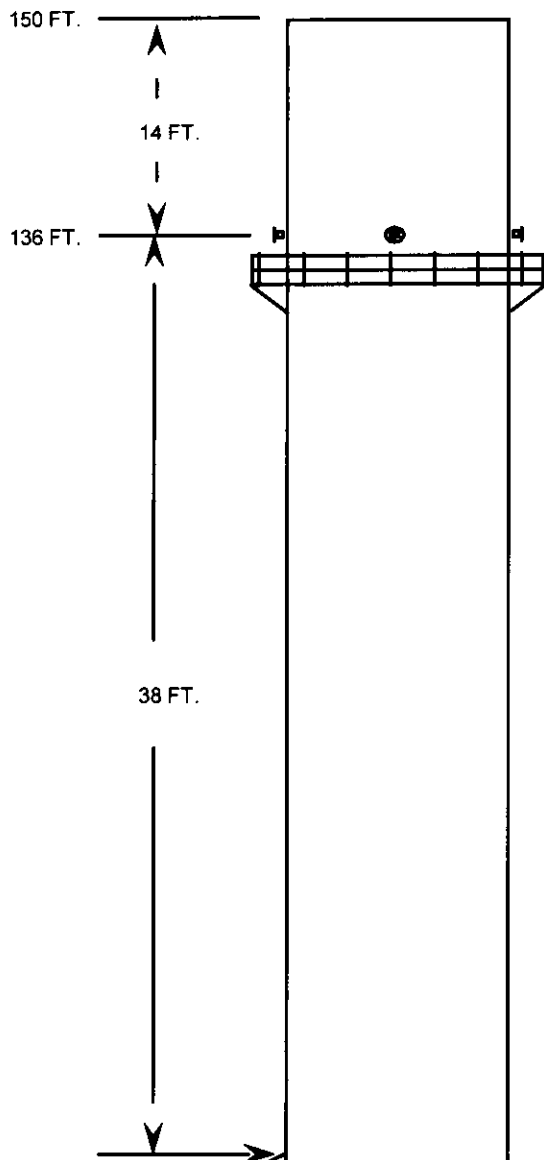
Section [3] of [3]

Additional Requirements Comment

Attachment 2

Polk Power Station Unit 1 Stack Test Location Sketch

**POLK POWER STATION
COMBUSTION TURBINE
COMBINED CYCLE UNIT NO.1
TEST LOCATION**

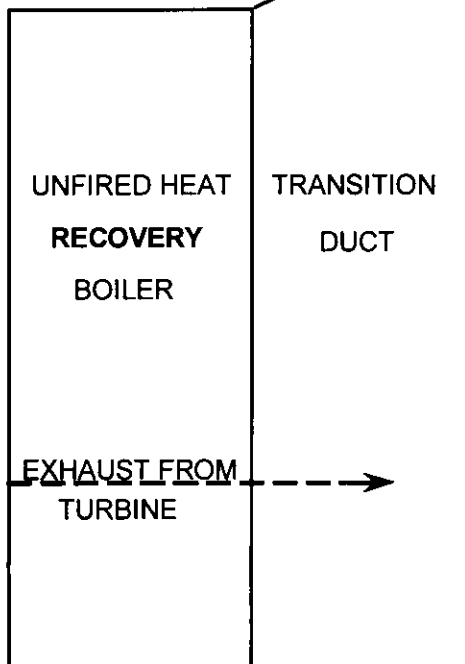


PORT LOCATION PLAN

**TRAVERSE
POINTS**

- 1 - 4.79"
- 2 - 15.28"
- 3 - 26.90"
- 4 - 40.36"
- 5 - 57.00"
- 6 - 81.17"

**ADD 13" PORT LENGTH
TO POINTS**



STACK DIAMETERS DOWNSTREAM
FROM DISTURBANCE = 2.0
STACK DIAMETERS UPSTREAM
FROM DISTURBANCE = 0.7
STACK DIAMETER = 19.0 FT.
STACK AREA = 283.529 SQ. FT.
STACK AREA = 40828.138 SQ. IN.

Attachment 3

Sulfuric Acid Plant Stack Test Location Sketch

**POLK POWER STATION
UNIT NO.1 ACID PLANT TEST LOCATION
SAMPLING TRAVERSE POINTS**

TRAVERSE POINTS	% OF STACK DIAMETER	IN. FROM STACK WALL
1	2.6 %	3.12
2	8.2 %	9.84
3	14.6 %	17.52
4	22.6 %	27.12
5	34.2 %	41.04

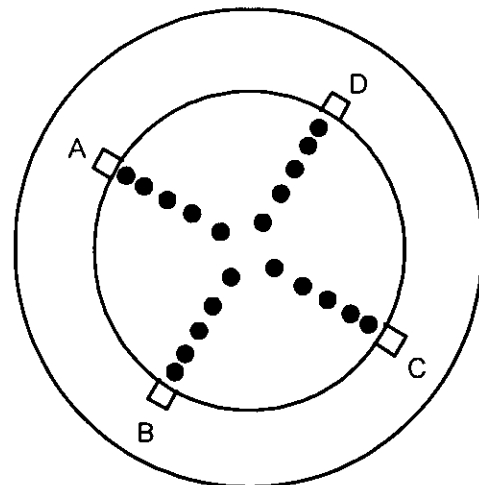
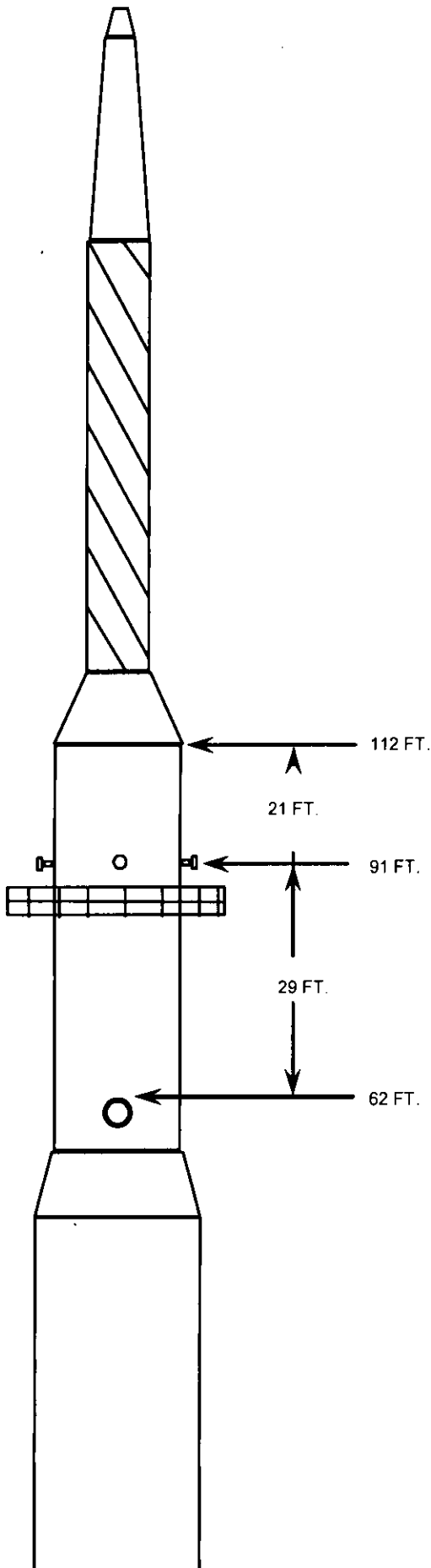
Overall Stack Height = 198 feet

STACK DIAMETERS DOWNSTREAM
FROM DISTURBANCE = 2.9

STACK DIAMETERS UPSTREAM
FROM DISTURBANCE = 2.1

STACK DIAMETER = 10.0 FT. ID.
STACK AREA = 78.540 SQ. FT.

PORT LENGTH = 9.0 IN.



PORT LOCATION PLAN

Attachment 1

Air Construction Permit Application



Department of Environmental Protection

Division of Air Resource Management

APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

Air Construction Permit – Use this form to apply for an air construction permit for a proposed project:

- subject to prevention of significant deterioration (PSD) review, nonattainment area (NAA) new source review, or maximum achievable control technology (MACT) review; or
- where the applicant proposes to assume a restriction on the potential emissions of one or more pollutants to escape a federal program requirement such as PSD review, NAA new source review, Title V, or MACT; or
- at an existing federally enforceable state air operation permit (FESOP) or Title V permitted facility.

Air Operation Permit – Use this form to apply for:

- an initial federally enforceable state air operation permit (FESOP); or
- an initial/revised/renewal Title V air operation permit.

Air Construction Permit & Revised/Renewal Title V Air Operation Permit (Concurrent Processing Option)

– Use this form to apply for both an air construction permit and a revised or renewal Title V air operation permit incorporating the proposed project.

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: Tampa Electric Company	
2. Site Name: Polk Power Station	
3. Facility Identification Number: 1050233	
4. Facility Location...: Street Address or Other Locator: 9995 State Route 37 South City: Mulberry County: Polk Zip Code: 33860-0775	
5. Relocatable Facility? <input type="checkbox"/> Yes <input checked="" type="checkbox"/> No	6. Existing Title V Permitted Facility? <input checked="" type="checkbox"/> Yes <input type="checkbox"/> No

Application Contact

1. Application Contact Name: Raiza Calderon, Engineer —Air Programs	
2. Application Contact Mailing Address... Organization/Firm: Tampa Electric Company Street Address: P.O. Box 111 City: Tampa State: FL Zip Code: 33601	
3. Application Contact Telephone Numbers... Telephone: (813) 228-4369 ext. Fax: (813) 228-1308	
4. Application Contact Email Address: <u>rcalderon@tecoenergy.com</u>	

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	3/2/04
2. Project Number(s):	1050233-019-Be
3. PSD Number (if applicable):	
4. Siting Number (if applicable):	

APPLICATION INFORMATION

Purpose of Application

This application for air permit is submitted to obtain: (Check one)

Air Construction Permit

Air construction permit.

Air Operation Permit

- Initial Title V air operation permit.
 Title V air operation permit revision.
 Title V air operation permit renewal.
 Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is required.
 Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is not required.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit (Concurrent Processing)

- Air construction permit and Title V permit revision, incorporating the proposed project.
 Air construction permit and Title V permit renewal, incorporating the proposed project.

Note: By checking one of the above two boxes, you, the applicant, are requesting concurrent processing pursuant to Rule 62-213.405, F.A.C. In such case, you must also check the following box:

- I hereby request that the department waive the processing time requirements of the air construction permit to accommodate the processing time frames of the Title V air operation permit.

Application Comment

Tampa Electric Company (TEC) requests authorization to conduct a test burn of petroleum coke at its Polk Power Station (PPS) integrated gasification combined-cycle (IGCC) facility located on State Road 37 South in Mulberry, Polk County, Florida.

The PPS Solid Fuel Gasification System (EU ID 006) is presently authorized to process coal or coal/petroleum coke blends containing a maximum of 60.0 percent petroleum coke by weight by FINAL Permit No.: 1050233-016-AV. TEC requests authorization to conduct a test burn of up to 100 percent petroleum coke, including a flux, with a maximum sulfur content of 6.0 percent by weight.

Use of 100 percent petroleum coke will potentially affect emissions from the combined-cycle unit (EU ID 001), the sulfuric acid plant (EU ID 004), and the solid fuel gasification system (EU 006). The purpose of the test burn is to evaluate the feasibility of gasifying 100 percent petroleum coke and to document that use of 100 percent petroleum coke will not result in a major modification to the PPS under the Prevention of Significant Deterioration (PSD) regulatory program.

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Proc. Fee
001	260 MW Combined-Cycle Combustion Turbine	ACM1	N/A
004	Sulfuric Acid Plant	ACM1	N/A
006	Solid Fuel Gasification System	ACM1	N/A

Application Processing Fee

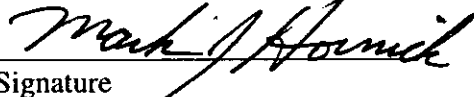
Check one: Attached - Amount: \$ _____ Not Applicable

A permit processing fee is not required for a modification to a Title V source pursuant to Rule 62-4.050(4)(a)2., F.A.C.

APPLICATION INFORMATION

Owner/Authorized Representative Statement

Complete if applying for an air construction permit or an initial FESOP.

1. Owner/Authorized Representative Name: Mark J. Hornick, General Manager
2. Owner/Authorized Representative Mailing Address... Organization/Firm: Tampa Electric Company Street Address: P.O. Box 111 City: Tampa State: FL Zip Code: 33601-0111
3. Owner/Authorized Representative Telephone Numbers... Telephone: (813) 288-1111 ext. 39988 Fax: (863) 428-5927
4. Owner/Authorized Representative Email Address: mjhornick@tecoenergy.com
5. Owner/Authorized Representative Statement: <i>I, the undersigned, am the owner or authorized representative of the facility addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other requirements identified in this application to which the facility is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit.</i>  Signature <u>2/27/06</u> Date

APPLICATION INFORMATION

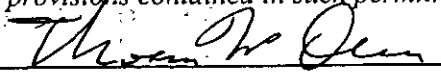
Application Responsible Official Certification N/A

Complete if applying for an initial/revised/renewal Title V permit or concurrent processing of an air construction permit and a revised/renewal Title V permit. If there are multiple responsible officials, the "application responsible official" need not be the "primary responsible official."

1. Application Responsible Official Name:
2. Application Responsible Official Qualification (Check one or more of the following options, as applicable): <input type="checkbox"/> For a corporation, the president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit under Chapter 62-213, F.A.C. <input type="checkbox"/> For a partnership or sole proprietorship, a general partner or the proprietor, respectively. <input type="checkbox"/> For a municipality, county, state, federal, or other public agency, either a principal executive officer or ranking elected official. <input type="checkbox"/> The designated representative at an Acid Rain source.
3. Application Responsible Official Mailing Address... Organization/Firm: Street Address: City: State: Zip Code:
4. Application Responsible Official Telephone Numbers... Telephone: ext. Fax:
5. Application Responsible Official Email Address:
6. Application Responsible Official Certification: <i>I, the undersigned, am a responsible official of the Title V source addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other applicable requirements identified in this application to which the Title V source is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit. Finally, I certify that the facility and each emissions unit are in compliance with all applicable requirements to which they are subject, except as identified in compliance plan(s) submitted with this application.</i> _____ Signature Date

APPLICATION INFORMATION

Professional Engineer Certification

1. Professional Engineer Name: Thomas W. Davis Registration Number: 36777
2. Professional Engineer Mailing Address... Organization/Firm: Environmental Consulting & Technology, Inc. Street Address: 3701 Northwest 98th Street City: Gainesville State: FL Zip Code: 32606
3. Professional Engineer Telephone Numbers... Telephone: (352) 332-0444 ext. Fax: (352) 332-6722
4. Professional Engineer Email Address: tdavis@ectinc.com
5. Professional Engineer Statement: <i>I, the undersigned, hereby certify, except as particularly noted herein*, that:</i> <i>(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this application for air permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and</i> <i>(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.</i> <i>(3) If the purpose of this application is to obtain a Title V air operation permit (check here <input type="checkbox"/>, if so), I further certify that each emissions unit described in this application for air permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance plan and schedule is submitted with this application.</i> <i>(4) If the purpose of this application is to obtain an air construction permit (check here <input checked="" type="checkbox"/>, if so) or concurrently process and obtain an air construction permit and a Title V air operation permit revision or renewal for one or more proposed new or modified emissions units (check here <input type="checkbox"/>, if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.</i> <i>(5) If the purpose of this application is to obtain an initial air operation permit or operation permit revision or renewal for one or more newly constructed or modified emissions units (check here <input type="checkbox"/>, if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.</i>  Signature _____ Date <u>2/23/06</u> (seal)

* Attach any exception to certification statement.

APPLICATION INFORMATION

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates... Zone 17 East (km) 402.45 North (km) 3,067.35		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) 27/43/43 Longitude (DD/MM/SS) 81/59/23	
3. Governmental Facility Code: 0	4. Facility Status Code: A	5. Facility Major Group SIC Code: 49	6. Facility SIC(s): 4911
7. Facility Comment :			

Facility Contact

1. Facility Contact Name: Mike Perkins, Environmental Coordinator
2. Facility Contact Mailing Address... Organization/Firm: Tampa Electric Company Street Address: P.O. Box 111 City: Tampa State: FL Zip Code: 33601-0111
3. Facility Contact Telephone Numbers: Telephone: (813) 228-1111 ext.39109 Fax: (863) 428-5927
4. Facility Contact Email Address: msperkins@tecoenergy.com

Facility Primary Responsible Official N/A

Complete if an "application responsible official" is identified in Section I. that is not the facility "primary responsible official."

1. Facility Primary Responsible Official Name:
2. Facility Primary Responsible Official Mailing Address... Organization/Firm: Street Address: City: State: Zip Code:
3. Facility Primary Responsible Official Telephone Numbers... Telephone: () - ext. Fax: () -
4. Facility Primary Responsible Official Email Address:

Facility Regulatory Classifications

Check all that would apply *following* completion of all projects and implementation of all other changes proposed in this application for air permit. Refer to instructions to distinguish between a “major source” and a “synthetic minor source.”

1. <input type="checkbox"/> Small Business Stationary Source	<input type="checkbox"/> Unknown
2. <input type="checkbox"/> Synthetic Non-Title V Source	
3. <input checked="" type="checkbox"/> Title V Source	
4. <input checked="" type="checkbox"/> Major Source of Air Pollutants, Other than Hazardous Air Pollutants (HAPs)	
5. <input type="checkbox"/> Synthetic Minor Source of Air Pollutants, Other than HAPs	
6. <input type="checkbox"/> Major Source of Hazardous Air Pollutants (HAPs)	
7. <input checked="" type="checkbox"/> Synthetic Minor Source of HAPs	
8. <input checked="" type="checkbox"/> One or More Emissions Units Subject to NSPS (40 CFR Part 60)	
9. <input type="checkbox"/> One or More Emissions Units Subject to Emission Guidelines (40 CFR Part 60)	
10. <input type="checkbox"/> One or More Emissions Units Subject to NESHAP (40 CFR Part 61 or Part 63)	
11. <input type="checkbox"/> Title V Source Solely by EPA Designation (40 CFR 70.3(a)(5))	
12. Facility Regulatory Classifications Comment:	

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
NOX	A	N
SO2	A	N
CO	A	N
PM10	A	N
PM	A	N
SAM	A	N
VOC	A	N
PB	B	N
H114 (Mercury Compounds)	B	N
H015 (Arsenic Compounds)	B	N
H021 (Beryllium Compounds)	B	N

C. FACILITY ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

<p>1. Facility Plot Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)</p> <p><input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Previously Submitted, Date: <u>April 2004</u></p>
<p>2. Process Flow Diagram(s): (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)</p> <p><input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Previously Submitted, Date: <u>April 2004</u></p>
<p>3. Precautions to Prevent Emissions of Unconfined Particulate Matter: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)</p> <p><input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Previously Submitted, Date: <u>April 2004</u></p>

Additional Requirements for Air Construction Permit Applications

<p>1. Area Map Showing Facility Location:</p> <p><input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Not Applicable (existing permitted facility)</p>
<p>2. Description of Proposed Construction or Modification:</p> <p><input type="checkbox"/> Attached, Document ID: See prior TEC test burn request submittals.</p>
<p>3. Rule Applicability Analysis:</p> <p><input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Not Applicable (No change in applicable requirements)</p>
<p>4. List of Exempt Emissions Units (Rule 62-210.300(3)(a) or (b)1., F.A.C.):</p> <p><input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Not Applicable (no exempt units at facility)</p>
<p>5. Fugitive Emissions Identification (Rule 62-212.400(2), F.A.C.):</p> <p><input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Not Applicable</p>
<p>6. Preconstruction Air Quality Monitoring and Analysis (Rule 62-212.400(5)(f), F.A.C.):</p> <p><input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Not Applicable</p>
<p>7. Ambient Impact Analysis (Rule 62-212.400(5)(d), F.A.C.):</p> <p><input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Not Applicable</p>
<p>8. Air Quality Impact since 1977 (Rule 62-212.400(5)(h)5., F.A.C.):</p> <p><input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Not Applicable</p>
<p>9. Additional Impact Analyses (Rules 62-212.400(5)(e)1. and 62-212.500(4)(e), F.A.C.):</p> <p><input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Not Applicable</p>
<p>10. Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.):</p> <p><input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Not Applicable</p>

EMISSIONS UNIT INFORMATION

Section [1] of [3]

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section:
Nominal 260 MW combined-cycle combustion turbine

3. Emissions Unit Identification Number: **011**

4. Emissions Unit Status Code: A	5. Commence Construction Date: N/A	6. Initial Startup Date: N/A	7. Emissions Unit Major Group SIC Code: 49	8. Acid Rain Unit? <input checked="" type="checkbox"/> Yes <input type="checkbox"/> No
--	--	--	--	--

9. Package Unit:
Manufacturer: General Electric Model Number: 7F

10. Generator Nameplate Rating: **260 MW**

11. Emissions Unit Comment:

EMISSIONS UNIT INFORMATION

Section [1] of [3]

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description:

NOx

Nitrogen diluent injection and syngas water saturation (syngas)

Water injection (distillate fuel oil)

2. Control Device or Method Code(s): **028 (water injection)**

EMISSIONS UNIT INFORMATION

Section [1] of [3]

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:	N/A
2. Maximum Production Rate:	N/A
3. Maximum Heat Input Rate:	1,765 million Btu/hr
4. Maximum Incineration Rate:	pounds/hr N/A tons/day
5. Requested Maximum Operating Schedule:	24 hours/day 7 days/week 52 weeks/year 8,760 hours/year
6. Operating Capacity/Schedule Comment:	Maximum heat rate is 1,765 MMBtu/hr (distillate fuel oil) and 1,755 MMBtu/hr (syngas). Both rates are on a monthly average basis.

EMISSIONS UNIT INFORMATION

Section [1] of [3]

C. EMISSION POINT (STACK/VENT) INFORMATION

(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: CT-01		2. Emission Point Type Code: 1	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: N/A			
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: N/A			
5. Discharge Type Code: V	6. Stack Height: 150 feet	7. Exit Diameter: 19.0 feet	
8. Exit Temperature: 340 °F	9. Actual Volumetric Flow Rate: 1,290,000 acfm	10. Water Vapor: % N/A	
11. Maximum Dry Standard Flow Rate: dscfm N/A		12. Nonstack Emission Point Height: feet N/A	
13. Emission Point UTM Coordinates... N/A Zone: East (km): North (km):		14. Emission Point Latitude/Longitude... N/A Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
15. Emission Point Comment:			

EMISSIONS UNIT INFORMATION

Section [1] of [3]

D. SEGMENT (PROCESS/FUEL) INFORMATION**Segment Description and Rate: Segment 1 of 2**

1. Segment Description (Process/Fuel Type): Combustion turbine fired with syngas.		
2. Source Classification Code (SCC): 1-01-019-01		3. SCC Units: Million Cubic Feet Burned
4. Maximum Hourly Rate: 9.24	5. Maximum Annual Rate: 80,914.7	6. Estimated Annual Activity Factor: N/A
7. Maximum % Sulfur: 0.07	8. Maximum % Ash: N/A	9. Million Btu per SCC Unit: 190
10. Segment Comment: Maximum hourly rate (Field 4), maximum annual rate (Field 5), and million Btu/SCC unit (Field 9) based on average fuel heat content of 190 Btu/cubic foot.		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): Combustion turbine fired with distillate fuel oil.		
2. Source Classification Code (SCC): 2-01-001-01		3. SCC Units: Thousand Gallons Burned
4. Maximum Hourly Rate: 12.71	5. Maximum Annual Rate: 11,131.32	6. Estimated Annual Activity Factor: N/A
7. Maximum % Sulfur: .05	8. Maximum % Ash: .01	9. Million Btu per SCC Unit: 138.9
10. Segment Comment: Maximum hourly rate (Field 4), maximum annual rate (Field 5), and million Btu/SCC unit (Field 9) based on average fuel heat content of 138,900 Btu/gal. Maximum annual rate (Field 5) based on maximum 10 percent capacity factor for distillate fuel oil firing.		

EMISSIONS UNIT INFORMATION

Section [1] of [3]

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
1 - CO			EL
2 - VOC			EL
3 - NOX	028		EL
4 - PM/PM10			EL
5 - SO2			EL
6 - PB			EL
7 - SAM			EL
8 - H015 (arsenic)			EL
9 - H021 (beryllium)			EL
10 - H114 (mercury)			EL

**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL/ESTIMATED FUGITIVE EMISSIONS**

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted:	2. Total Percent Efficiency of Control:
3. Potential Emissions: <div style="display: flex; justify-content: space-between; width: 100%;"> lb/hour tons/year </div>	4. Synthetically Limited? <input type="checkbox"/> Yes <input type="checkbox"/> No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions:	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: <p>TEC is not requesting any revisions to currently authorized emission standards as specified in FINAL Title V Permit No. 1050233-016-AV. The information requested by Section F1 regarding potential (allowable) emissions for EU ID 001 can be found in FINAL Title V Permit No. V1050233-016-AV.</p>	

**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method): TEC is not requesting any revisions to currently authorized emission standards as specified in FINAL Title V Permit No. 1050233-016-AV. The information requested by Section F2 regarding allowable emissions for EU ID 001 can be found in FINAL Title V Permit No. 1050233-016-AV.	

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: <p style="text-align: center;">VE10</p>	2. Basis for Allowable Opacity: <input checked="" type="checkbox"/> Rule <input type="checkbox"/> Other
3. Allowable Opacity: Normal Conditions: 10 % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: <p>EPA Reference Method 9 annually.</p>	
5. Visible Emissions Comment: <p>Limit applicable for syngas-firing.</p>	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: <p style="text-align: center;">VE20</p>	2. Basis for Allowable Opacity: <input checked="" type="checkbox"/> Rule <input type="checkbox"/> Other
3. Allowable Opacity: Normal Conditions: 20 % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
6. Method of Compliance: <p>EPA Reference Method 9 annually.</p>	
7. Visible Emissions Comment: <p>Limit applicable for distillate fuel oil-firing.</p>	

EMISSIONS UNIT INFORMATION

Section [1] of [3]

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor ___ of ___

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	<input type="checkbox"/> Rule <input type="checkbox"/> Other
4. Monitor Information: Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: Information regarding EU ID 001 CEMS remains unchanged from the data previously provided to the Department.	

Continuous Monitoring System: Continuous Monitor ___ of ___

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	<input type="checkbox"/> Rule <input type="checkbox"/> Other
4. Monitor Information: Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

EMISSIONS UNIT INFORMATION

Section [1] of [3]

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) <input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Previously Submitted, Date: April 2004
2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) <input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Previously Submitted, Date: April 2004
3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) <input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Previously Submitted, Date: April 2004
4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Previously Submitted, Date: _____ <input checked="" type="checkbox"/> Not Applicable (construction application)
5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Previously Submitted, Date _____ <input checked="" type="checkbox"/> Not Applicable
6. Compliance Demonstration Reports/Records <input type="checkbox"/> Attached, Document ID: _____ Test Date(s)/Pollutant(s) Tested: _____ <input type="checkbox"/> Previously Submitted, Date: _____ Test Date(s)/Pollutant(s) Tested: _____ <input type="checkbox"/> To be Submitted, Date (if known): _____ Test Date(s)/Pollutant(s) Tested: _____ <input checked="" type="checkbox"/> Not Applicable Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7. Other Information Required by Rule or Statute <input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Not Applicable

EMISSIONS UNIT INFORMATION

Section [1] of [3]

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)) <input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Not Applicable
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.) <input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Not Applicable
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) <input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Not Applicable

Additional Requirements for Title V Air Operation Permit Applications N/A

1. Identification of Applicable Requirements <input type="checkbox"/> Attached, Document ID: _____
2. Compliance Assurance Monitoring <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Not Applicable
3. Alternative Methods of Operation <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Not Applicable
4. Alternative Modes of Operation (Emissions Trading) <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Not Applicable
5. Acid Rain Part Application <input type="checkbox"/> Certificate of Representation (EPA Form No. 7610-1) <input type="checkbox"/> Copy Attached, Document ID: _____ <input type="checkbox"/> Acid Rain Part (Form No. 62-210.900(1)(a)) <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Previously Submitted, Date: _____ <input type="checkbox"/> Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Previously Submitted, Date: _____ <input type="checkbox"/> New Unit Exemption (Form No. 62-210.900(1)(a)2.) <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Previously Submitted, Date: _____ <input type="checkbox"/> Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Previously Submitted, Date: _____ <input type="checkbox"/> Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Previously Submitted, Date: _____ <input type="checkbox"/> Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Previously Submitted, Date: _____ <input type="checkbox"/> Not Applicable

EMISSIONS UNIT INFORMATION

Section [1] of [3]

Additional Requirements Comment

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EMISSIONS UNIT INFORMATION

Section [2] of [3]

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

3. Description of Emissions Unit Addressed in this Section:
Sulfuric Acid Plant

3. Emissions Unit Identification Number: **004**

4. Emissions Unit Status Code: A	5. Commence Construction Date: N/A	6. Initial Startup Date: N/A	7. Emissions Unit Major Group SIC Code: 49	8. Acid Rain Unit? <input type="checkbox"/> Yes <input checked="" type="checkbox"/> No
--	--	--	--	--

9. Package Unit:
Manufacturer: **N/A** Model Number: **N/A**

10. Generator Nameplate Rating: **N/A**

12. Emissions Unit Comment:

EMISSIONS UNIT INFORMATION

Section [2] of [3]

Emissions Unit Control Equipment

2. Control Equipment/Method(s) Description:

SO₂

Double contact process

H₂SO₄ Mist

Mist eliminators

2. Control Device or Method Code(s): **044 (double contact process), 152 (mist eliminators)**

EMISSIONS UNIT INFORMATION

Section [2] of [3]

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:	N/A	
2. Maximum Production Rate:	77,640 tons/year of 100 percent sulfuric acid	
3. Maximum Heat Input Rate:	N/A million Btu/hr	
4. Maximum Incineration Rate:	pounds/hr N/A tons/day	
5. Requested Maximum Operating Schedule:	24 hours/day 52 weeks/year	7 days/week 8,760 hours/year
6. Operating Capacity/Schedule Comment:		

EMISSIONS UNIT INFORMATION

Section [2] of [3]

C. EMISSION POINT (STACK/VENT) INFORMATION
 (Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: AP-01		2. Emission Point Type Code: 1	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: N/A			
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: N/A			
5. Discharge Type Code: V	6. Stack Height: 199 feet	7. Exit Diameter: 2.5 feet	
8. Exit Temperature: 180 °F	9. Actual Volumetric Flow Rate: 17,660 acfm	10. Water Vapor: % N/A	
11. Maximum Dry Standard Flow Rate: dscfm N/A		12. Nonstack Emission Point Height: feet N/A	
13. Emission Point UTM Coordinates... N/A Zone: East (km): North (km):		14. Emission Point Latitude/Longitude... N/A Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
15. Emission Point Comment: Two other emission points exist within the sulfuric acid plant. The propane-fired H₂S-to-SO₂ conversion furnace vents directly to the atmosphere during acid plant warmup - 15 MMBtu/hr maximum heat input during warmup; vented to atmosphere only when process gas is not being treated. Also, a propane-fired SO₂-toSO₃ converter preheater (9 MMBtu/hr heat input) produces a non-contact exhaust stream that vents directly to the atmosphere.			

EMISSIONS UNIT INFORMATION

Section [2] of [3]

D. SEGMENT (PROCESS/FUEL) INFORMATION**Segment Description and Rate:** Segment 1 of 1

1. Segment Description (Process/Fuel Type): Sulfuric acid production.		
2. Source Classification Code (SCC): 3-01-023-99		3. SCC Units: Tons produced or manufactured
4. Maximum Hourly Rate: 8.90	5. Maximum Annual Rate: 77,640.0	6. Estimated Annual Activity Factor: N/A
7. Maximum % Sulfur: N/A	8. Maximum % Ash: N/A	9. Million Btu per SCC Unit: N/A
10. Segment Comment:		

Segment Description and Rate: Segment of

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):		3. SCC Units:
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL/ESTIMATED FUGITIVE EMISSIONS**

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted:		2. Total Percent Efficiency of Control:	
3. Potential Emissions: lb/hour tons/year		4. Synthetically Limited? <input type="checkbox"/> Yes <input type="checkbox"/> No	
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year			
6. Emission Factor: Reference:		7. Emissions Method Code:	
8. Calculation of Emissions:			
9. Pollutant Potential/Estimated Fugitive Emissions Comment: TEC is not requesting any revisions to currently authorized emission standards as specified in FINAL Title V Permit No. 1050233-016-AV. The information requested by Section F1 regarding potential (allowable) emissions for EU ID 004 can be found in FINAL Title V Permit No. V1050233-016-AV.			

**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
 ALLOWABLE EMISSIONS**

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	5. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method): TEC is not requesting any revisions to currently authorized emission standards as specified in FINAL Title V Permit No. 1050233-016-AV. The information requested by Section F2 regarding allowable emissions for EU ID 004 can be found in FINAL Title V Permit No. 1050233-016-AV.	

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: VE10	2. Basis for Allowable Opacity: <input checked="" type="checkbox"/> Rule <input type="checkbox"/> Other
3. Allowable Opacity: Normal Conditions: 10 % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
8. Method of Compliance: EPA Reference Method 9 annually.	
9. Visible Emissions Comment: Rule 62-296.402(2)(a), F.A.C.	

Visible Emissions Limitation: Visible Emissions Limitation of

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: <input type="checkbox"/> Rule <input type="checkbox"/> Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
10. Method of Compliance:	
11. Visible Emissions Comment:	

EMISSIONS UNIT INFORMATION

Section [2] of [3]

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor ___ of ___ N/A

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	<input type="checkbox"/> Rule <input type="checkbox"/> Other
4. Monitor Information: Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor ___ of ___

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	<input type="checkbox"/> Rule <input type="checkbox"/> Other
4. Monitor Information: Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

EMISSIONS UNIT INFORMATION

Section [2] of [3]

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) <input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Previously Submitted, Date: April 2004
2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) <input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Previously Submitted, Date: April 2004
3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) <input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Previously Submitted, Date: April 2004
4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Previously Submitted, Date: _____ <input checked="" type="checkbox"/> Not Applicable (construction application)
5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Previously Submitted, Date _____ <input checked="" type="checkbox"/> Not Applicable
6. Compliance Demonstration Reports/Records <input type="checkbox"/> Attached, Document ID: _____ Test Date(s)/Pollutant(s) Tested: _____ <input type="checkbox"/> Previously Submitted, Date: _____ Test Date(s)/Pollutant(s) Tested: _____ <input type="checkbox"/> To be Submitted, Date (if known): _____ Test Date(s)/Pollutant(s) Tested: _____ <input checked="" type="checkbox"/> Not Applicable Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7. Other Information Required by Rule or Statute <input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Not Applicable

EMISSIONS UNIT INFORMATION

Section [2] of [3]

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)) <input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Not Applicable
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.) <input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Not Applicable
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) <input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Not Applicable

Additional Requirements for Title V Air Operation Permit Applications N/A

1. Identification of Applicable Requirements <input type="checkbox"/> Attached, Document ID: _____
2. Compliance Assurance Monitoring <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Not Applicable
3. Alternative Methods of Operation <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Not Applicable
4. Alternative Modes of Operation (Emissions Trading) <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Not Applicable
5. Acid Rain Part Application <input type="checkbox"/> Certificate of Representation (EPA Form No. 7610-1) <input type="checkbox"/> Copy Attached, Document ID: _____ <input type="checkbox"/> Acid Rain Part (Form No. 62-210.900(1)(a)) <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Previously Submitted, Date: _____ <input type="checkbox"/> Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Previously Submitted, Date: _____ <input type="checkbox"/> New Unit Exemption (Form No. 62-210.900(1)(a)2.) <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Previously Submitted, Date: _____ <input type="checkbox"/> Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Previously Submitted, Date: _____ <input type="checkbox"/> Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Previously Submitted, Date: _____ <input type="checkbox"/> Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Previously Submitted, Date: _____ <input type="checkbox"/> Not Applicable

EMISSIONS UNIT INFORMATION

Section [2] of [3]

Additional Requirements Comment

[Empty rectangular box for additional requirements comment]

EMISSIONS UNIT INFORMATION

Section [3] of [3]

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

4. Description of Emissions Unit Addressed in this Section:
Solid Fuel Gasification System

3. Emissions Unit Identification Number: **006**

4. Emissions Unit Status Code: A	5. Commence Construction Date: N/A	6. Initial Startup Date: N/A	7. Emissions Unit Major Group SIC Code: 49	8. Acid Rain Unit? <input type="checkbox"/> Yes <input checked="" type="checkbox"/> No
--	--	--	--	--

9. Package Unit:
Manufacturer: **N/A** Model Number: **N/A**

10. Generator Nameplate Rating: **N/A**

13. Emissions Unit Comment:
System converts solid fuel (coal or coal/petroleum coke blends) into syngas for the purpose of electric generation. This application request authorization to conduct a test burn of up to 100 percent by weight petroleum coke with a flux.

EMISSIONS UNIT INFORMATION

Section [3] of [3]

Emissions Unit Control Equipment

3. Control Equipment/Method(s) Description:

Flare (during emergencies and startup/shutdown).

2. Control Device or Method Code(s): **023 (flare)**

EMISSIONS UNIT INFORMATION

Section [3] of [3]

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:	2,325 ton/day on a dry basis	
2. Maximum Production Rate:	N/A	
3. Maximum Heat Input Rate:	N/A million Btu/hr	
4. Maximum Incineration Rate:	pounds/hr	N/A
	tons/day	
5. Requested Maximum Operating Schedule:	24 hours/day	7 days/week
	52 weeks/year	8,760 hours/year
6. Operating Capacity/Schedule Comment:	<p>This application request authorization to conduct a test burn of up to 100 percent by weight petroleum coke with a flux.</p>	

EMISSIONS UNIT INFORMATION

Section [3] of [3]

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)**Emission Point Description and Type N/A**

1. Identification of Point on Plot Plan or Flow Diagram:		2. Emission Point Type Code:	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:			
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:			
5. Discharge Type Code:		6. Stack Height: feet	7. Exit Diameter: feet
8. Exit Temperature: °F	9. Actual Volumetric Flow Rate: acfm		10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm		12. Nonstack Emission Point Height: feet	
13. Emission Point UTM Coordinates... Zone: East (km): North (km):		14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
15. Emission Point Comment:			

EMISSIONS UNIT INFORMATION

Section [3] of [3]

D. SEGMENT (PROCESS/FUEL) INFORMATION**Segment Description and Rate:** Segment 1 of 1

1. Segment Description (Process/Fuel Type): Solid fuel gasification (coal, petroleum coke, and coal/petroleum blends)		
2. Source Classification Code (SCC): 3-01-999-99		3. SCC Units: Tons processed
4. Maximum Hourly Rate: N/A	5. Maximum Annual Rate: 952,020	6. Estimated Annual Activity Factor: N/A
7. Maximum % Sulfur: N/A	8. Maximum % Ash: N/A	9. Million Btu per SCC Unit: N/A
10. Segment Comment: Maximum daily rate will not exceed 2,325 tons on a dry basis.		

Segment Description and Rate: Segment of

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):		3. SCC Units:
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions of N/A

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	6. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

EMISSIONS UNIT INFORMATION

Section [3] of [3]

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation of N/A

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: <input type="checkbox"/> Rule <input type="checkbox"/> Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
12. Method of Compliance:	
13. Visible Emissions Comment:	

Visible Emissions Limitation: Visible Emissions Limitation of

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: <input type="checkbox"/> Rule <input type="checkbox"/> Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
14. Method of Compliance:	
15. Visible Emissions Comment:	

EMISSIONS UNIT INFORMATION

Section [3] of [3]

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor ___ of ___ N/A

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	<input type="checkbox"/> Rule <input type="checkbox"/> Other
4. Monitor Information: Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor ___ of ___

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	<input type="checkbox"/> Rule <input type="checkbox"/> Other
4. Monitor Information: Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

EMISSIONS UNIT INFORMATION

Section [3] of [3]

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

<p>1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)</p> <p><input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Previously Submitted, Date: April 2004</p>
<p>2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)</p> <p><input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Previously Submitted, Date: April 2004</p>
<p>3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)</p> <p><input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Previously Submitted, Date: April 2004</p>
<p>4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)</p> <p><input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Previously Submitted, Date: _____</p> <p><input checked="" type="checkbox"/> Not Applicable (construction application)</p>
<p>5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)</p> <p><input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Previously Submitted, Date _____</p> <p><input checked="" type="checkbox"/> Not Applicable</p>
<p>6. Compliance Demonstration Reports/Records</p> <p><input type="checkbox"/> Attached, Document ID: _____</p> <p>Test Date(s)/Pollutant(s) Tested: _____</p> <p><input type="checkbox"/> Previously Submitted, Date: _____</p> <p>Test Date(s)/Pollutant(s) Tested: _____</p> <p><input type="checkbox"/> To be Submitted, Date (if known): _____</p> <p>Test Date(s)/Pollutant(s) Tested: _____</p> <p><input checked="" type="checkbox"/> Not Applicable</p> <p>Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.</p>
<p>7. Other Information Required by Rule or Statute</p> <p><input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Not Applicable</p>

EMISSIONS UNIT INFORMATION

Section [3] of [3]

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)) <input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Not Applicable
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.) <input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Not Applicable
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) <input type="checkbox"/> Attached, Document ID: _____ <input checked="" type="checkbox"/> Not Applicable

Additional Requirements for Title V Air Operation Permit Applications N/A

1. Identification of Applicable Requirements <input type="checkbox"/> Attached, Document ID: _____
2. Compliance Assurance Monitoring <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Not Applicable
3. Alternative Methods of Operation <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Not Applicable
4. Alternative Modes of Operation (Emissions Trading) <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Not Applicable
5. Acid Rain Part Application <input type="checkbox"/> Certificate of Representation (EPA Form No. 7610-1) <input type="checkbox"/> Copy Attached, Document ID: _____ <input type="checkbox"/> Acid Rain Part (Form No. 62-210.900(1)(a)) <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Previously Submitted, Date: _____ <input type="checkbox"/> Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Previously Submitted, Date: _____ <input type="checkbox"/> New Unit Exemption (Form No. 62-210.900(1)(a)2.) <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Previously Submitted, Date: _____ <input type="checkbox"/> Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Previously Submitted, Date: _____ <input type="checkbox"/> Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Previously Submitted, Date: _____ <input type="checkbox"/> Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) <input type="checkbox"/> Attached, Document ID: _____ <input type="checkbox"/> Previously Submitted, Date: _____ <input type="checkbox"/> Not Applicable

EMISSIONS UNIT INFORMATION

Section [3] of [3]

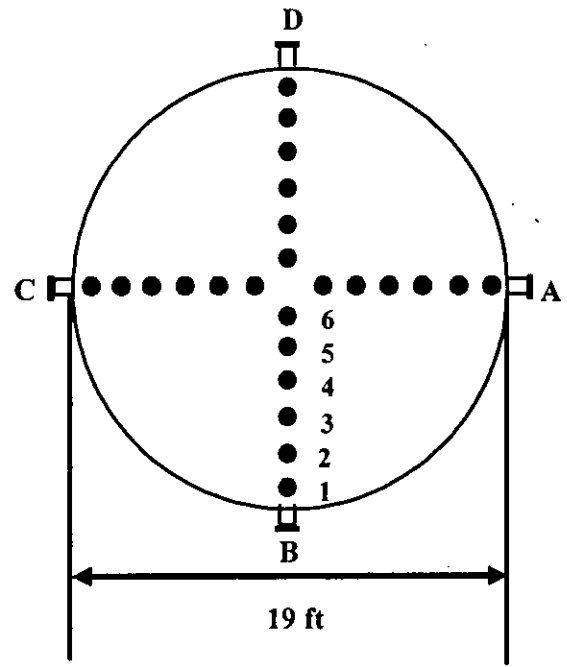
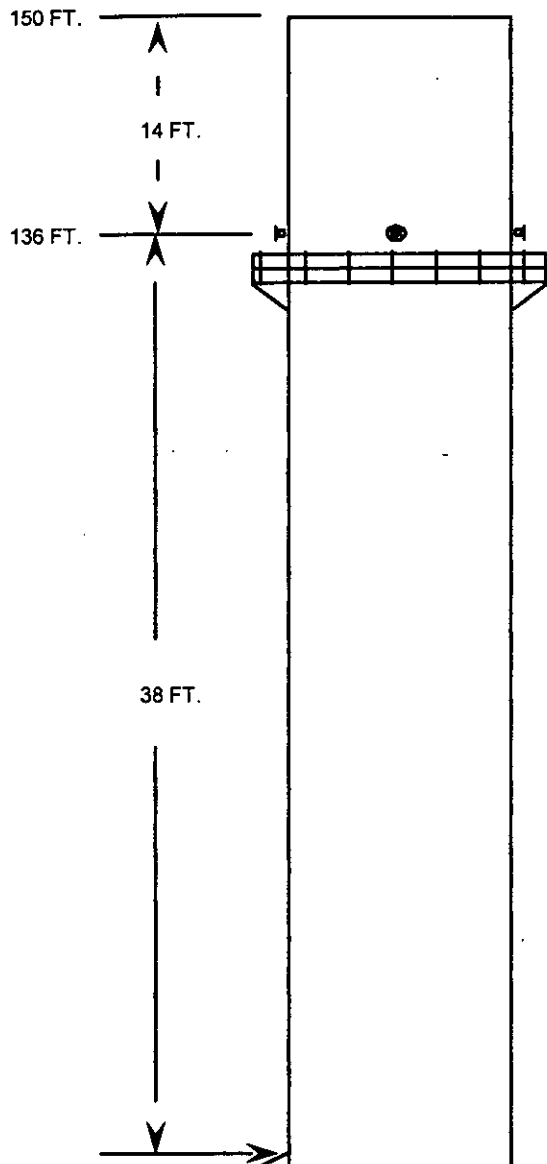
Additional Requirements Comment

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Attachment 2

Polk Power Station Unit 1 Stack Test Location Sketch

POLK POWER STATION COMBUSTION TURBINE COMBINED CYCLE UNIT NO.1 TEST LOCATION

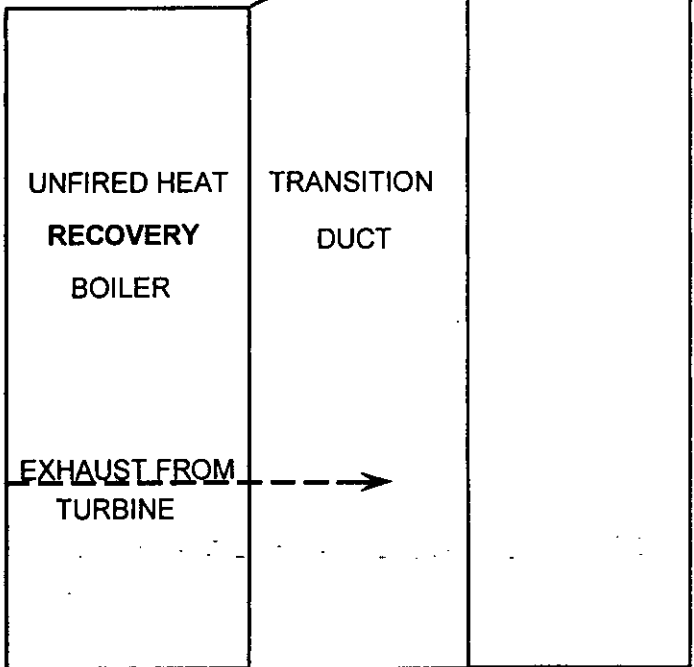


PORT LOCATION PLAN

TRAVERSE POINTS

- 1 - 4.79"
- 2 - 15.28"
- 3 - 26.90"
- 4 - 40.36"
- 5 - 57.00"
- 6 - 81.17"

ADD 13" PORT LENGTH
TO POINTS



STACK DIAMETERS DOWNSTREAM
FROM DISTURBANCE = 2.0
STACK DIAMETERS UPSTREAM
FROM DISTURBANCE = 0.7
STACK DIAMETER = 19.0 FT.
STACK AREA = 283.529 SQ. FT.
STACK AREA = 40828.138 SQ. IN.



Attachment 3

Sulfuric Acid Plant Stack Test Location Sketch

**POLK POWER STATION
UNIT NO.1 ACID PLANT TEST LOCATION
SAMPLING TRAVERSE POINTS**

TRAVERSE POINTS	% OF STACK DIAMETER	IN. FROM STACK WALL
1	2.6 %	3.12
2	8.2 %	9.84
3	14.6 %	17.52
4	22.6 %	27.12
5	34.2 %	41.04

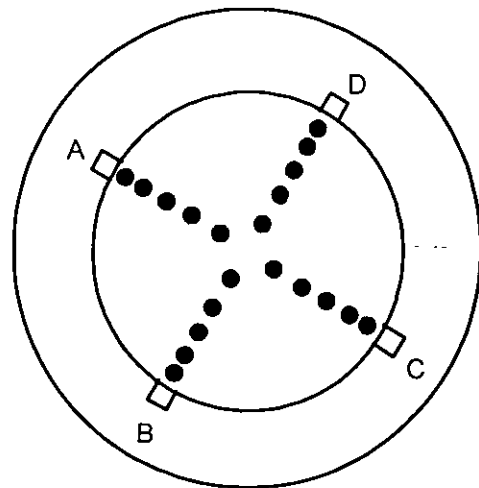
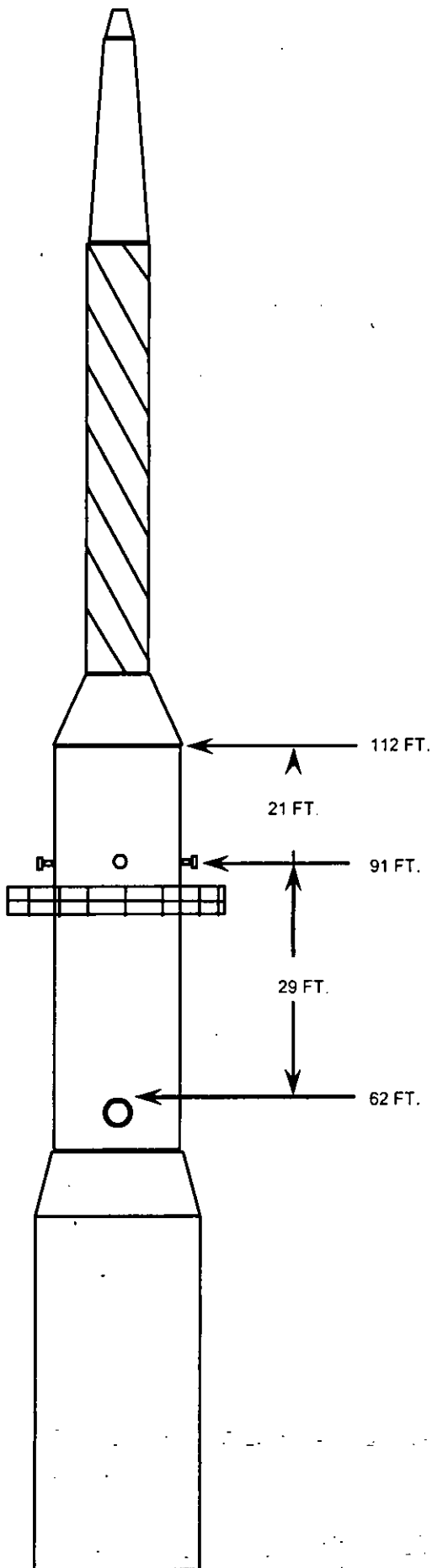
Overall Stack Height = 198 feet

STACK DIAMETERS DOWNSTREAM FROM DISTURBANCE = 2.9

STACK DIAMETERS UPSTREAM FROM DISTURBANCE = 2.1

STACK DIAMETER = 10.0 FT. ID.
STACK AREA = 78.540 SQ. FT.

PORT LENGTH = 9.0 IN.



PORT LOCATION PLAN



POLK POWER STATION

The Power of Clean-Coal Technology

Description

A state-of-the-art "integrated coal gasification combined-cycle" power plant that produces enough electricity to serve 56,000 homes. The facility began operation in fall 1996.

Location

A 4,300-acre tract of land (previously mined for phosphate) recommended by an independent citizens Power Plant Siting Task Force. It is located in Polk County, Florida on State Road 37. It is approximately 40 miles southeast of Tampa and 60 miles southwest of Orlando.

Technology

A 250-megawatt "Integrated Gasification Combined-Cycle" facility that is among the nation's cleanest, most efficient and most economical power generation units.

The plant is a first-of-its-kind combination of two leading technologies. The first technology is called "coal gasification," which uses coal to create a clean-burning gas. This second technology is called "combined cycle," which is the most efficient method of producing electricity commercially available today. The integration of these technologies allows Tampa Electric to couple the high efficiency of the combined-cycle design with the low cost of coal to produce a clean fuel.

Construction began in 1994. The complete 250-megawatt integrated facility began commercial operation in the fall of 1996.

The gasification portion of the plant produces a clean coal gas which fuels the combustion turbine. Coal is combined with oxygen in the gasifier to produce the gaseous fuel. The gas is then thoroughly cleaned in several stages to remove sulfur, particulates and other contaminants. After cleaning, the coal gas ("syngas") is used in the combustion turbine to produce electricity.

Combined cycle is more efficient because it reuses exhaust heat to produce more electricity. Combined-cycle design consists of a combustion turbine/generator, a heat recovery steam generator, and a steam turbine/generator. The exhaust heat from the combustion turbine is recovered in the heat recovery steam generator to produce steam. This steam then passes through a steam turbine to power another generator, which produces more electricity.

Tampa Electric has been awarded over \$140-million in funding through the U.S. Department of Energy's Clean Coal Technology Program to demonstrate this special integration of technology.

In 2000, Polk Unit 2 opened as a 170 megawatt, dual-fuel peaking unit. Polk Unit 3 is under construction and should come online in 2002, as an additional 170 megawatt, dual-fuel peaking unit. Over the next 20 years, Tampa Electric will add to the plant to meet any additional customer energy needs not served through conservation or cogeneration. The total capacity at this plant is expected to reach about 1,150 megawatts.

Environment

The coal gasification unit provides clean, coal-fueled power, with the gas cleanup process removing 98 percent of the sulfur in the coal gas and all of the flyash. This exceeds the performance of today's most advanced coal-fired generating units. The sulfuric acid and slag by products are sold for reuse in industry.

Existing "mine cuts" on the phosphate land were modified to become the plant's cooling reservoir. Much of the power station's storm water is reused in the plant or cooling reservoir. And, the combined-cycle technology requires much less cooling water than conventional technology.

Employment

About 1,200 contract construction workers were employed by the general contractor at the site during the peak of construction activity. A team of over 70 full-time personnel employed by Tampa Electric Company manage and operate the Polk Power Station plant. Tampa Electric recruited individuals that are multi-skilled, multi-functional, and demonstrate the ability to be part of a dynamic, high performance team.

Tampa Electric Company

Tampa Electric Company is a regulated public utility that has been serving West Central Florida since 1899. Today it delivers electricity to more than 570,000 customers in a 2,000-square-mile area that includes almost all of Hillsborough County and parts of Polk, Pasco, and Pinellas counties. Commercial, residential and industrial customers depend on Tampa Electric for reliable power and value-added energy services.

For More Information

Please call our toll-free number **1-888-223-0800**, or write: Tampa Electric Co., Polk Power Station, P.O. Box 111, Tampa, FL 33601. We're online at www.tampaelectric.com

Tampa Electric Company



Biomass Test Burn Report

Polk Power Station Unit 1

April 2002

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1.0 Introduction

Tampa Electric Company (TEC) conducted a test burn on December 31, 2001 at the Polk Power Station (PPS) Unit 1. The purpose of this test burn was to investigate the effects of gasifying a small portion of biomass as a constituent of the feedstock that is processed to form the synthetic gas (syngas) fired in the combustion turbine (CT). TEC performed this test under the authority of the temporary permit issued by the Florida Department of Environmental Protection (the Department) dated December 21, 2001. The data from this test indicate there is no increase in monitored air emissions (NO_x and SO_2) from PPS Unit 1 as a result of the addition of a small amount of biomass as a constituent of the feedstock for PPS Unit 1. This report constitutes the required Test Burn Report for the biomass test burn. The background for this test including materials and methods used for the test are presented within. Also, the results of the test are presented and discussed.

2.0 Background

PPS Unit 1 uses an Integrated Gasification Combined Cycle Process (IGCC) to convert solid fuels into a syngas that can be fired in a CT. The IGCC process is capable of handling a variety of fuels as feedstock to the gasification process. Currently, PPS Unit 1 is typically fired on a blend of 55% petcoke and 45% coal. Thus, a similar blend was used during the test burn with biomass fuel added to allow for direct comparisons. This biomass test burn fired a fuel blend that consisted of approximately 55% petcoke, 44% coal, and 1% biomass.

The test conducted on December 31, 2001 was conducted:

- To determine if any technical impediments exist to co-firing biomass as a small portion of the feedstock to the gasifier, and
- To characterize the emissions resulting from co-firing biomass.

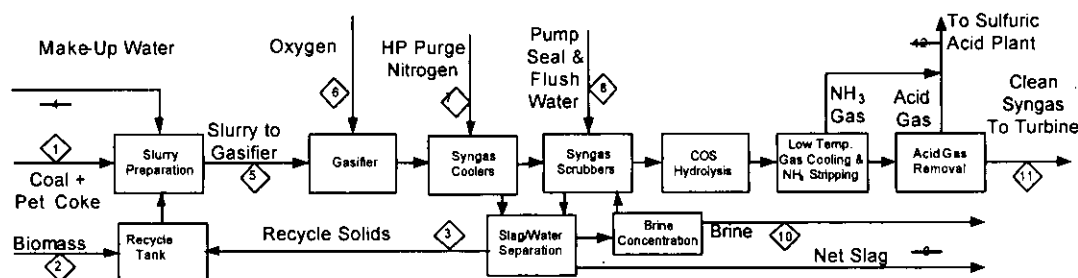
The IGCC process consists of several steps that ultimately result in the production of electrical power (Figure 1). Solid fuel is homogenized and mixed with water to produce slurry. The slurry is then passed to the gasifier that produces a high-pressure combustible gas (synthetic gas or "syngas"). After cooling the syngas, residual material from the gasification process is separated, the slag is rejected and the water and combustible fines are recycled back into the gasifier. Cooled syngas is passed through scrubbers that remove any remaining particulate matter. The syngas then is subjected to a series of steps that remove sulfur and convert the removed sulfur to H_2SO_4 . This clean syngas is then fired in a CT that turns an electrical generator. Hot exhaust gasses from the CT are used to create steam that powers a steam turbine that also produces electrical power. This system is an efficient means to produce electrical power on a commercial scale.

2.1 Biomass Fuel Handling

This test used 8.8 tons of coarsely ground eucalyptus as the biomass fuel. Approximately 60 eucalyptus trees were harvested from the Common Purpose, Inc. grove located on land provided by the Tampa Airport Authority. The felled trees were sectioned into 4 foot lengths and passed through a portable hammer mill and trommel screen up to 5 times to produce material fine enough to avoid fouling the pumps and screens of PPS Unit 1's slurry feed system. The biomass fuel was transported to PPS in an enclosed trailer.

Biomass fuel was stored, handled, at processed at PPS. Biomass fuel was staged in a cleaned bin. Approximately 800 pounds of biomass fuel were loaded with a small loader into each of 22 tote sacks. The tote sacks were suspended individually over the recycled fines tank (Figure 1). The biomass fuel was introduced into the process via a stirred recycle tank and mixed with water over a period of 8 ½ hours. The mixed biomass fuel was blended with the normal coal and petcoke mixture to form slurry that was fed to the gasifier.

Figure 1. Block flow diagram of PPS Unit 1 gasifier section showing process stream designations.



2.2 Process Data Collection

Data were collected for key variables throughout IGCC process to allow for analysis of air quality impacts of this test burn. Feedstock analyses were conducted on both the standard petcoke/coal blend and the biomass fuel. Feedstock analyses include elemental, metals, and ash mineral compositions and heating value for each fuel type. Process streams were analyzed for elemental and ash composition, mass flow, and heat content at 12 points in the IGCC process corresponding to the 12 numerical labels shown in Figure 1. An overall mass balance for the gasifier was calculated during the test burn for each of the 12 process points indicated in Figure 1. Stack emissions data were collected for NO_x and SO_2 by the Continuous Emissions Monitoring System (CEMS) and reported at one-hour intervals throughout the test burn. Emissions data were reported in parts per million (ppm) for each pollutant.

2.3 Emissions data comparisons

Emissions data obtained during the test burn were compared to representative emissions data from December 29, 2001. The baseline data from December 29, 2001 were chosen as representative since those data are from the same petcoke/coal feedstock, were obtained immediately prior to the test burn, and Unit 1 was functioning normally and operating under similar conditions as those during the test burn. Larger baseline data sets were examined for possible comparison, but it was found that variability in process parameters such as heat input made statistical comparisons problematic for data that were obtained more than a few days prior to the test burn. For example, for the time period of December 26, 2001 to December 30, 2001 the sample variance for heat input in MMBtu was 12.4 times higher than the sample variance for the period December 29, 2001 to December 30, 2001 ($\sigma^2_{5\text{-day}} = 1639$ compared to $\sigma^2_{1\text{-day}} = 133$). Sample variance increased with time for heat input, power output, and for NO_x and SO_2 emissions levels.

2.4 Statistical Methods for Comparing Emissions Data

Emissions data from the test burn were analyzed and compared to the baseline data using a variety of statistical measures. Emissions data from both the test burn and the baseline periods were evaluated using the same statistical measures. Data from the CEMS were reported as the variables Heat Input (MMBtu), Power Output (MW), SO_2 (lb/MMBtu), SO_2 (ppm), NO_x (lb/MMBtu), NO_x (ppm). The statistics mean (μ), variance (σ^2), kurtosis, skewness, range, and 95% confidence interval were calculated for each variable. The mean and variance were used to compare the test burn emissions data to the baseline emissions data. Kurtosis, skewness, range, and 95% confidence interval were used to evaluate the quality of the emissions data and to make decisions about which comparative methods were appropriate to use in comparing test burn and baseline data. To compare test burn data to baseline data, each set of variables was examined using a two-sample F-test to make inferences about population variances and a two-sample t-test assuming unequal variances to make inferences about population means.

The comparative statistical methods used in this report require that certain assumptions be met before the results of these methods can be considered valid. Comparisons between the means of the test burn data and the baseline data are most useful in determining if there is a change in a process after a treatment is applied.

The statistic that is used to make comparisons between sample means is called a two-sample t-test. A t-test can be used to determine if two populations' means are equal at a given significance level. The significance level for this report is 95% ($\alpha = 0.05$) in all cases. A t-test compares the ratio of the sample means and variances to expected frequency distribution of a normal population at a specified error rate. The two-sample t-test is used to evaluate the hypothesis that two populations' means are equal against the alternative hypothesis that the two populations' means are unequal. The hypothesis of equal means is rejected when the calculated t-statistic is greater than the t-critical value at a given significance level. The validity of the t-test is based on several assumptions.

First, the two samples are independent. In practical terms, the assumption of independence means that the two samples are drawn from two different populations and that the elements of one sample are unrelated to those of the second sample. This assumption is met since the data for the test burn and the baseline emissions were taken by a discrete sampling device at different times with all variables controlled except for biomass used as a feedstock in the test burn.

Second, the two samples are drawn from a normally distributed population. Though the assumption of a normal population distribution is less critical than the assumption of independent samples it is still important to verify that the assumption is met. Since each data point collected by the CEMS is actually a discrete point sample of a continuously variable exhaust stream the potential sample population is quite large. For modest-sized samples (combined sample size ≥ 30) drawn from a large population the distribution approaches normal even with modest skewness in the two populations. The tendency of a relative frequency histogram to approach normal when samples are repeatedly drawn from a large population is called the Central Limit Theorem. Since the combined sample size of the test burn and baseline data is 28, it is prudent to verify that the Central Limit Theorem applies by calculating the skewness and kurtosis for each variable in each data set. Skewness is a measure of the central tendency of a frequency distribution that relates to the symmetry of the peak in relation to the mean, mode, and median of the distribution. Normal distributions have a skewness of 0. Kurtosis is a measure of the size of the tails of a frequency distribution. Normal distributions have a kurtosis of 0. If the sample's frequency distribution does not approximate normality, then the non-parametric Wilcoxon rank sum statistic can be used to compare population means. The Wilcoxon rank sum test is not as likely to declare a difference in population means when it exists as is a t-test since the Wilcoxon rank sum is based on relative magnitudes rather than the magnitudes of the observations.

Third, variances are assumed to be equal. Since the t-test pools sample variances when computing the test statistic, unequal variances can have an effect on the nominal significance and confidence probabilities of the statistical test, especially when sample sizes are different. However, a computationally more difficult version of the t-test that allows for the use of separate variances for each sample can be used when variances are not equal.

A statistical test for comparing two population variances is the F-test. The F-test is used to check the validity of the equal variance assumption for a two-sample t-test. The F-test compares the ratio of the sample variances to an expected population variance frequency distribution that is defined by the degrees of freedom associated with the samples. The F-test can be used to test the hypothesis that two sample variances are equal against the alternative hypothesis that two sample variances are not equal. The hypothesis of equal sample variances is rejected when the calculated F-statistic exceeds the F-critical value of the frequency distribution that is defined by the degrees of freedom for the two samples.

3.0 Results and Discussion

Biomass fuel comprised approximately 1.2% of PPS Unit 1's fuel during the 8-½ hour test burn. Biomass fuel generated approximately 860 kW of electrical power during the test burn. The addition of biomass into the feedstock tended cause a decrease in the heat content of the feedstock due to biomass' elemental composition relative to the composition of the base fuel. Emissions from Unit 1 did not increase with respect to baseline

during the test burn. There were no major technical impediments to the introduction of biomass into the feedstock of Unit 1. Logs of the biomass feed rate and certified truck scale tickets of the biomass delivery were maintained, and are provided in Appendix A.

3.1 Process

Biomass was introduced to the gasifier at a rate of 1,945 lb/hr. The biomass feed rate was approximately 1.2% of the base fuel feed rate of 164,840 lb/hr. The biomass fuel accounted for approximately 860 kW of electrical power out of a total of 220.5 MW generated during the test burn based on relative heating value and feed rates of the biomass fuel and the base fuel. Process results are summarized in Table 1. Plant performance from the operators' standpoint was indistinguishable from the normal petcoke/coal feedstock. Heat input to the CT during the test burn was on average 1667 ± 9.5 MMBtu compared to the heat input during the baseline period of 1681 ± 11.5 MMBtu, which were obtained from CEM data. (Note: The actual LHV to the CT during the test was 1473 mmbtu/hr, and HHV was 1583 mmbtu/hr. The CEMS reported HHV to the CT has a large error and this is why it should not be used.) Average CT power output was steady at 167.6 ± 0.1 MW during the test burn compared to 167.5 ± 0.08 MW during the baseline period.

Table 1. General process parameters for biomass and base fuels during the biomass test burn.

Parameter	Base Fuel	Biomass Fuel	Total or Weighted Average	
Feed Rate (lb/hr)	164,840	1,945	166,786	Total
Moisture Content (Wt%)	7.82%	46.8%	8.27%	Avg
Higher Heating Value (Btu/lb)	13,322	4,424	13,218	Avg
Higher Heating Value (MMBtu/hr)	2,196	8.6	2,205	Avg
Net Power Production (kW)	219,640	860	220,500	Total

3.2 Mass Balance

The overall mass balance for the gasification process was estimated at 12 different process points. The mass balance is presented in Table 2 and the stream numbers correspond to the numerical labels in Figure 1. Process streams 1-2 and 4-8 are feed streams and have a total flow rate of 381 thousand pounds per hour (KPPH). Process streams 9-12 are output streams and have a total flow rate of 381 KPPH. Process streams 3 and 5 are key internal streams and have flow rates of 81 and 264 KPPH, respectively.

Table 2. Overall mass balance for PPS Unit 1 gasifier section during biomass test burn. Units are in thousand pounds per hour (KPPH). Stream number corresponds to numerical labels in Figure 1.

Input (Feed) Streams		
Stream Number	Stream Description	Flow (KPPH)
1	Coal / Petroleum Coke Blend	164.84
2	Biomass	1.95
4	Make-Up Water To Slurry	16.5
6	Oxygen To Gasifier	166.94
7	High Pressure Purge/Sootblowing N ₂	11.07
8	Pump Seal/Instrument Flush Water	19.49
TOTAL SYSTEM INPUT		380.79

Product (Output) Streams		
Stream Number	Stream Description	Flow (KPPH)
9	Slag	17.36
10	Brine	0.02
11	Clean Syngas To Combustion Turbine	337.78
12	Acid and NH ₃ Gas To Sulfuric Acid Plant	25.62
TOTAL SYSTEM OUTPUT STREAMS		380.78

Key Internal Streams		
Stream Number	Stream Description	Flow (KPPH)
5	Slurry To Gasifier	264.4
3	Recycle Solids To Slurry Preparation	81.12

3.3 Process Stream Flows and Compositions

Each of the 12 process streams identified by numerical labels in Figure 1 was analyzed for composition and mass flows (Tables 3 and 4). Table 3 presents the stream flows and compositions for the slurry preparation area (streams 1-5). Table 3 also presents the heat content of streams 1-3 and 5. Calculated and analytically derived values for all parameters of stream 1 (base fuel) are presented in Table 3 for comparison purposes. Calculated and laboratory analytical values agree within the sampling and analytical accuracy range of the measurements. The addition of the biomass fuel to the base fuel resulted in a net decrease in composition (as a dry weight %) for all constituents except oxygen which increased by 0.25% and ash which increased by 0.01% over the calculated base fuel composition. Table 4 presents the flows and compositions for the gasification system (streams 3 and 5-12). Table 4 presents the compositional analysis of the clean syngas (stream 11) and residual materials from the gasification process (streams 9 and 3) as requested by the Department.

**Table 3. Slurry preparation area stream flows and compositions during test burn.
KPPH = thousand pounds per hour, AR = as received.**

Stream Number		1	1	2	3	4	5	
		COKE + COAL (Lab)	COKE + COAL (Calculated)	BIOMASS	COMBINED FRESH FUELS	RECYCLE SOLIDS	MAKE-UP WATER	SLURRY TO GASIFIER
Units								
COMPOSITION								
C	Wt % Dry	82.88	82.24	49.18	82.02	66.26		80.68
H	"	4.5	4.71	5.78	4.71	0.29		4.34
N	"	1.85	1.83	0.24	1.81	0.95		1.74
S	"	2.99	3.15	0.06	3.13	2.31		3.06
O	"	3.53	3.67	39.42	3.92	0		3.58
ASH	"	4.25	4.4	5.32	4.41	30.19		6.6
TOTAL	"	100	100	100	100	100		100
SUBTOTAL KPPH DRY FLOW		151.95	151.95	1.035	152.985	14.196		167.181
H2O	Wt % AR	7.82	7.82	46.8	8.27	82.5		36.77
H2O	KPPH	12.891	12.891	0.91	13.801	66.924	16.496	97.22
TOTAL FLOW	KPPH AR	164.841	164.841	1.945	166.786	81.12		264.401
MASS FLOW								
C	Dry Lb/Hr	125936	124962	509	125471	9406		134877
H	"	6838	7150	60	7210	41		7251
N	"	2811	2774	2	2777	135		2911
S	"	4543	4791	1	4791	328		5119
O	"	5364	5582	408	5990	0		5990
ASH	"	6458	6691	55	6746	4286		11031
Ar	"	0	0	0	0	0		0
SUBTOTAL-Dry Solids		151950	151950	1035	152985	14196		167181
WATER / MOISTURE	lb/hr	12891	12891	910	13801	66924	16496	97220
TOTAL	"	164841	164841	1945	166786	81120		264401
HEAT CONTENT								
Calculated HHV BTU/Lb (Dry)		14491	14511	8419	14470	9698		14065
Measured HHV BTU/Lb (Dry)		14435		8213		9811		13990
Balance HHV BTU/Lb (Dry)		14452	14452	8315	14411	9701		14011
Balance HHV BTU/Lb (AR)		13322	13322	4424	13218	1698		
Balance HHV MMBTU/Hr		2196	2196	8.6	2205	138		2342

**Table 4. Gasification system stream flows and compositions during test burn.
KPPH = thousand pounds per hour.**

STREAM NUMBER	GASIFICATION SYSTEM INPUTS					GASIFICATION SYSTEM OUTPUTS							
	GAS STREAMS	UNITS	SLURRY TO GASIFIER		HP PURGE NITROGEN	SEAL & FLUSH WATER	TOTAL SYSTEM INPUT	9	3	10	11	12	TOTAL SYSTEM OUTPUT
			OXYGEN										
CO	VOL. %		0		0						44.77	2.06	
H ₂	VOL. %		0		0						36.02	0.52	
CH ₄	VOL. %		0		0						0.02	0.02	
CO ₂	VOL. %		0		0						15.01	66.42	
N ₂	VOL. %		1.08		99.99						3.33	0	
Ar	VOL. %		2.01		0						0.65	0	
H ₂ O	VOL. %		0		0						0.21	5.26	
H ₂ S	VOL. %		0		0						0.01	21.02	
CO ₂	VOL. %		0		0						0.01	0.06	
NH ₃	VOL. %		0		0						0	4.62	
O ₂	VOL. %		96.9		0.01						0	0.01	
TOTAL	VOL. %		100		100						100	100	
MOLECULAR	LB/MOL		32.12		28.02						21.1	38.76	
R WT	E												
FLOW	KSCFH		1972.6		149.9						6075.5	250.9	
SOLID AND LIQUID STREAMS													
C	WT. %	80.68					47.37	66.26					
H	WT. %	4.34					0.31	0.29	7.49				
N	WT. %	1.74					0.44	0.95	26.22				
S	WT. %	3.06					1.47	2.31					
O	WT. %	3.58					0	0					
ASH	WT. %	6.6					55.41	30.19	66.29				
TOTAL	WT. %	100					100	100	100				
DRY FLOW	KPPH	167.181					12.149	14.196	0.021				
H ₂ O	WT. %	36.77					30	82.5					
H ₂ O FLOW	KPPH	97.22			19.489		5.207	66.924					
TOTAL	KPPH	264.401					17.356	81.12					
FLOW													
ELEMENTAL FLOWS / BALANCE:													
C	L.B./HR	134877	0	0			134877	5148	9406		114880	5443	134877
H	L.B./HR	18130	0	0	2181		20311	620	2530	2	11709	450	20311
N	L.B./HR	2911	1580	11066			15558	53	135	6	14936	478	15558
S	L.B./HR	5119	0	0			5119	179	328		144	4469	5119
O	L.B./HR	92331	161177	1	17308		270817	4624	50435		191926	14832	270817
ASH	L.B./HR	11031	0	0			11031	6732	4286	14	0	0	11031
Ar	L.B./HR	0	4184	0			4184				4184	0	4184
TOTAL	L.B./HR	264401	166941	11067	19489		461898	17356	81120	21	337779	25623	461898

3.4 Feedstock Analysis

A complete feedstock laboratory analysis is presented in Table 5. Both the base fuel and the biomass fuel were analyzed for elemental composition, ash composition, metal, and heat content. Compared to the base fuel, biomass fuel has greater moisture content, ash, hydrogen, oxygen, and some metals. Compared to the base fuel, biomass fuel has lesser carbon, nitrogen, and sulfur content. The difference in elemental composition results in a much lesser heat content for biomass fuel than for the base fuel (biomass fuel heat content was 56.8% of the heat content of the base fuel) and accounts for the dilution effect observed when the fuels are blended.

Table 5. Feed stock analysis of fuels used during test burn.

		Fuel	Coal/Coke Blend	Biomass
Total Moisture		Units		
Ultimate Analysis		Wt %	7.82	46.8
	Ash	Wt % (Dry Basis)	4.25	5.32
	C	Wt % (Dry Basis)	82.88	49.18
	H	Wt % (Dry Basis)	4.5	5.78
	N	Wt % (Dry Basis)	1.85	0.24
	S	Wt % (Dry Basis)	2.99	0.06
	O	Wt % (Dry Basis)	3.53	39.42
Heating Value				
	Measured HHV	BTU/Lb (Dry Basis)	14435	8213
	Calculated HHV	BTU/Lb (Dry Basis)	14490	8419
Miscellaneous				
	T ₂₅₀	Deg F	2560	2188
	Chlorine	Wt % (Dry Basis in Coal)	0.02	0.07
	Fluorine	Wt % (Dry Basis in Coal)	<0.01	34
	Chromium	PPM (Wt) In Ash	136	85.9
	Vanadium	Wt % In Ash	2.286	0.63
	Nickel	ug/g dry coal	166	1300
	Arsenic	ug/g dry coal	2.1	35.3
	Mercury	ug/g dry coal	0.03	0.02
	Lead	ug/g dry coal	2.6	116
	Beryllium	ug/g dry coal	1.3	9.2
Ash Minerals				
	CrO	Wt % In Ash	0.02	0.01
	V ₂ O ₅	Wt % In Ash	4.08	1.12
	NiO	Wt % In Ash	0.50	0.17
	As ₂ O ₃	Wt % In Ash	0.0065	0.0050
	Hg	Wt % In Ash	0.000071	0.000002
	PbO	Wt % In Ash	0.0066	0.0120
	BeO	Wt % In Ash	0.0085	0.0030
	SiO ₂	Wt % In Ash	49.21	40.70
	Al ₂ O ₃	Wt % In Ash	20.52	4.98
	TiO ₂	Wt % In Ash	0.93	0.29
	Fe ₂ O ₃	Wt % In Ash	12.89	6.12
	CaO	Wt % In Ash	3.34	22.31
	MgO	Wt % In Ash	1.91	1.85
	Na ₂ O	Wt % In Ash	0.57	1.41
	K ₂ O	Wt % In Ash	2.04	3.64
	P ₂ O ₃	Wt % In Ash	0.16	1.44
	SO ₃	Wt % In Ash	3.4	3.67
	Sum of Determined Minerals	Wt % In Ash	99.07	87.73
	Undetermined Ash Minerals	Wt % In Ash	0.93	12.27

3.5 Emissions

A statistical analysis was performed comparing the mean NO_x and SO₂ emissions from the test burn to baseline emissions obtained immediately prior to the test burn. NO_x and SO₂ emissions were analyzed for both baseline and test burn periods on a volumetric (ppm) and mass flow (lb/hr) basis. The statistical analyses consisted of calculating descriptive statistics and making pair-wise comparisons of each pollutant's variance and mean for the baseline data and the test burn data. The results of the analyses conducted using volumetric data were consistent with the results obtained using mass data.

NO_x and SO₂ emissions during the test burn were found to be slightly lower than NO_x and SO₂ emissions during the baseline period. Figures 2 and 3 show graphs of test burn emissions compared to baseline emissions for NO_x and SO₂, respectively. Tables 6 and 7 present the summary results of the statistical analyses for the test burn and baseline emissions data for NO_x and SO₂, respectively. The results presented are in volumetric units (ppm), but identical relationships and statistical conclusions are obtained using mass flow units (lb/hr). Table 8 summarizes the statistics for NO_x and SO₂ emissions for the baseline and test burn periods in both volumetric and mass- flow units, for comparison.

Figure 2. NO_x emissions (ppm) from PPS Unit 1 during baseline and test burn periods.

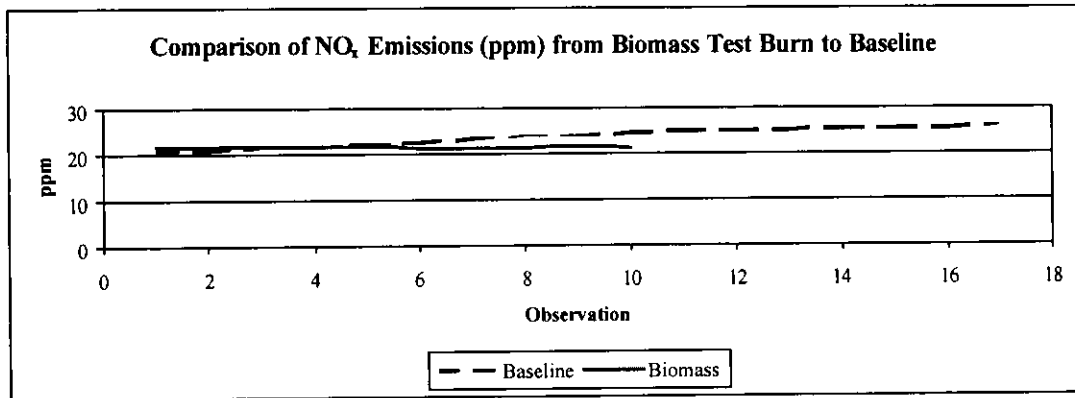
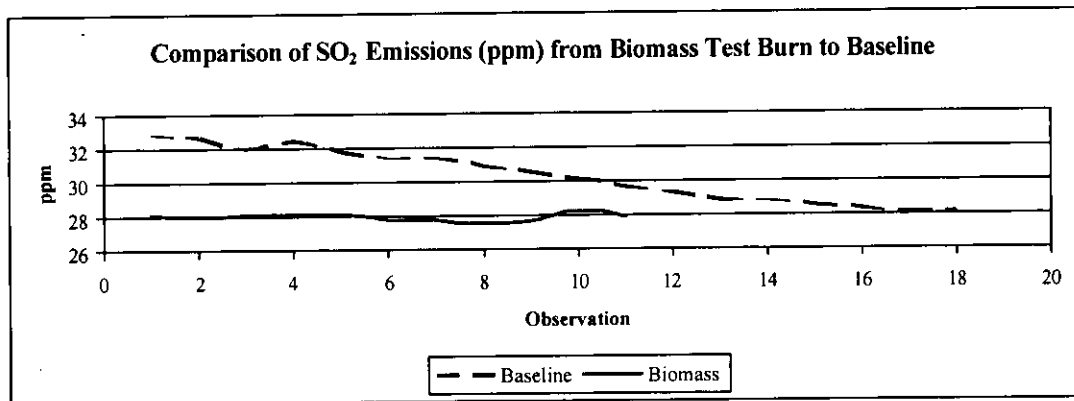


Figure 3. SO₂ emissions (ppm) from PPS Unit 1 during baseline and test burn periods.



Populations' mean and variance frequency distributions as measured by skewness and kurtosis approximated a normal distribution for both NO_x and SO₂ when the sizes of the data sets were considered. Two sample t-tests, assuming unequal variances, were used to test if the mean values for NO_x and SO₂ emissions were equal between the test burn and baseline emissions data. This was done because the F-tests rejected the hypothesis that the variances were equal between the test burn and the baseline emissions for

both NO_x and SO₂. The two sample t-tests results indicate that the observed differences in means are not due to chance at the 95% confidence level.

Table 6. Statistical analysis comparing variances and means of baseline and test burn data for NO_x emissions (ppm).

Parameter	Baseline	Biomass
Mean (ppm)	23.44	21.25
Variance	3.89	0.06
Observations	18	11
Hypothesized Difference in Variance or Mean	0	
df F-test (t-test)	17 (18)	10
F _{calc}	66.41	
Probability that calculated F is less than or equal to F _{crit}	5.02E-08	
F _{Crit}	2.81	
t _{calc}	4.64	
Probability that calculated t _{calc} is less than or equal to t _{crit}	2.03E-04	
t _{crit}	2.10	

Conclusion: Reject hypothesis that Variances or Means are equal.

Table 7. Statistical analysis comparing variances and means of baseline and test burn data for SO₂ emissions (ppm).

Parameter	Baseline	Biomass
Mean (ppm)	30.36	27.95
Variance	2.73	0.05
Observations	18	11
Hypothesized Difference in Variance or Mean	0	
df F-test (t-test)	17 (18)	10
F _{calc}	51.99	
Probability that calculated F is less than or equal to F _{crit}	1.66E-07	
F _{Crit}	2.81	
t _{calc}	6.11	
Probability that calculated t _{calc} is less than or equal to t _{crit}	9.00E-06	
t _{crit}	2.10	

Conclusion: Reject hypothesis that Variances or Means are equal.

Table 8. Comparison of baseline and test burn emissions in volumetric and mass flow units.

Parameter	NO _x				SO _x			
	ppm		lb/hr		ppm		lb/hr	
	Baseline	Test	Baseline	Test	Baseline	Test	Baseline	Test
Mean	23.4	21.3	134.1	123.2	30.4	27.9	241.6	225.1
Number of Observations	18	11	18	11	18	11	18	11
Standard Deviation	1.97	0.24	11.35	2.2	1.7	0.2	13.1	2.5
Range	6	0.7	32.8	7.1	4.8	0.8	40.9	8.3
Minimum	19.9	20.8	114.75	119.1	28.1	27.5	221.9	221.3
Maximum	25.9	21.5	147.6	126.2	32.9	28.3	262.8	229.6
95% Confidence Interval	22.4 - 24.4	21.1 - 21.5	128.5 - 139.8	121.7 - 124.7	29.6 - 31.2	27.7 - 28.1	235.1 - 248.1	223.4 - 226.8

4.0 Conclusion

The test burn data indicates that the gasification of biomass is technically feasible and will not adversely impact emissions from PPS Unit 1. PPS requests the flexibility to gasify non-treated biomass. TEC understands that an air construction permit application is be required to accommodate the changes necessary to handle the biomass fuel. TEC appreciates the Department's attention to this process.

Attachment 1
Polk Power Station Unit 1
Typical Petcoke Analysis

SGS MINERALS SERVICES

107 Pintail, St. Rose, Louisiana 70087 (504) 467-5522

TECO GULF BARGE REPORT

DATE REPORTED:	27-May-06	1:15 PM	TO :	Dan Akins
CARGO NO.:	12136B			John Yanik
DATE SAMPLED:	5/24-25/06			Gary Garbelman
CARGO TYPE:	PET COKE			Greg Riley
CARGO WEIGHT:	9,133.00	SHORT TONS		Lars Amundsen
GULF BARGE:	P. PALMER			Ruben Chavez
HOLD NUMBERS:	HOLD 2 ONLY			Tim Muncy
SAMPLING TYPE:	MECH.			Steve Mills
LAB NUMBER	89-6316-34			Marty Duff

OVERALL COMPOSITE ANALYSIS

BY HOLD ANALYSIS

	<u>DETERMINED</u>		<u>AS RECEIVED</u>			<u>DRY BASIS</u>		
	<u>AS RECEIVED</u>	:	<u>HOLD</u>	<u>SULFUR</u>	<u>BTU/LB</u>	<u>SULFUR</u>	<u>BTU/LB</u>	<u>SO₂ (95%)</u>
TOTAL MOISTURE	4.99	XXXXX	1	X	X	X	X	X
ASH CONTENT	0.35	*0.37	2	X	X	X	X	X
SULFUR CONTENT	6.32	*6.60	3	X	X	X	X	X
HEATING VALUE	14,322	*14958	4	X	X	X	X	X
MAF BTU/LB		15,130						
LBS. SO ₂ (95%)		8.38						
AIR DRY LOSS		4.24						
60 MESH MOIST.		0.77						

Attachment 2
Polk Power Station Unit 1
DOE Final Technical Report

**Tampa Electric Polk Power Station
Integrated Gasification Combined Cycle Project**

Final Technical Report

August 2002

Work Performed Under
Cooperative Agreement DE-FC-21-91MC27363

For:
The U.S. Department of Energy
Office of Fossil Energy
National Energy Technology Laboratory
Morgantown, West Virginia

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John McDaniel – Principal Author and Editor

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ACRONYMS, ABBREVIATIONS AND SYMBOLS

°C	degrees Celsius
°F	degrees Fahrenheit
\$	dollars (U.S.)
\$MM	millions of dollars (U.S.)
\$/kW	dollars per kilowatt
\$/ton	dollars per ton
\$/MMBtu	dollars per million British thermal unit
%	percent
AC	alternating current
acfm	actual cubic feet per minute
ACFH	actual cubic feet per hour
AGR	acid gas removal
APCI	Air Products and Chemicals, Inc.
Ar	argon, elemental
As	arsenic, elemental
ASU	air separation unit
atm	atmosphere(s)
avg.	average
ASTM	American Society for Testing and Materials
BACT	best available control technology
bbl	barrels
bbl/d	barrels per day
BFW	boiler feed water
BTU	British thermal unit(s)
BTU/kWh	British thermal unit(s) per kilowatt-hour
C	carbon, elemental
CA	cooperative agreement
CAA	Clean Air Act
CAAA	Clean Air Act Amendments of 1990
CC	combined cycle
CCT	clean coal technology
CCT III	third CCT program solicitation
CCT Program	Clean Coal Technology Demonstration Program
CEM	continuous emission monitoring
CFR	Code of Federal Regulations
CH ₄	methane
CI	combustion system inspection (Combustion Turbine)
Cl	chlorine, chloride
CO	carbon monoxide
CO ₂	carbon dioxide
Corp.	Corporation
COS	carbonyl sulfide
CSC	convective syngas cooler
CT	combustion turbine
CWR	cooling water return
CWS	cooling water supply

d	day(s)
dB	decibel(s)
DBB	double block and bleed
DCS	distributed control system
DGAN	diluent nitrogen
DOE	Department of Energy
dP	differential pressure
dscf	dry standard cubic feet
dscfm	dry standard cubic feet per minute
EIA	Energy information Administration
EPA	Environmental Protection Agency
EPC	engineer(ing)procure(ment)construct(ion)
EMP	environmental monitoring plan
EPRI	Electric Power Research Institute
ft, ft ² ft ³ ,	foot (feet), square feet, cubic feet
FOD	foreign object damage (Combustion Turbine)
gal	gallon(s)
gm	gram(s)
GE	General Electric
GOX	gaseous oxygen
GTC	Gasification Technologies Council
H ₂	hydrogen
H ₂ O	water
H ₂ S	hydrogen sulfide
H ₂ SO ₄	sulfuric acid
HCl	hydrogen chloride (gas)
Hg	mercury
HGP	hot gas path (Combustion Turbine)
HHV	high heating value (reference state = liquid water)
HP	high pressure (nominally 1350 to 1650 psig)
HPGAN	high pressure gaseous nitrogen
hr	hour(s)
HRSG	heat recovery steam generator
HSS	heat stable salts
IGCC	integrated gasification combined cycle
IP	intermediate pressure (nominally 410 psig)
ISEP	ion separation unit
in, in ² , in ³	inch(es), square inches, cubic inches
IR	infrared
KACFH	thousands of actual cubic feet per hour
KO	knock-out (e.g., KO drum)
KPPH	thousands of pounds per hour
KSCFH	thousands of standard cubic feet per hour
kg	kilogram(s)
kW	kilowatt(s)
kWh	kilowatthour(s)
l	liter
lb or lbs	pound or pounds

lb/hr	pound(s) per hour
lb/MMBtu	pound(s) per million British thermal units of heat input
LEL	lower explosive limit
LHV	lower heating value (reference state = water vapor)
LIN	liquid nitrogen
LOI	loss on ignition (combustible portion of a solid fuel)
LP	low pressure (nominally 45 to 65 psig)
LTGC	low temperature gas cooling
LTSA	long term service agreement (combined cycle equipment)
MAC	main air compressor (Air Separation Plant)
MCC	motor control center
MDEA	methyldiethanolamine
mg	milligram
min	minutes(s)
MMBTU	million British thermal units
MMSCF	millions of standard cubic feet
MNQC	multi-nozzle quiet combustor (combustion turbine)
mo	month(s)
MP	medium pressure (nominally 420 psig)
MW	megawatt(s)
MWe	megawatt(s)-electric
MWh	megawatt-hour(s)
N ₂	nitrogen, gas
NEPA	National Environmental Policy Act
NETL	National Energy Technology Laboratory
NGCC	natural gas fired combined cycle
NH ₃	ammonia
No.	number
NO, NO ₂ , NO _x	nitric oxide, nitrogen dioxide, nitrogen oxides
NPDES	National Pollutant Discharge Elimination System
NSPS	new source performance standards
O&M	operating and maintenance
OEM	original equipment manufacturer
O ₂	oxygen, gas
P&ID's	pipng and instrument drawings
PEECC	packaged electrical and electronic control center
pH	the negative logarithm of the hydrogen ion concentration
PLC	programmable logic controller
PM ₁₀	particulate matter less than 10 microns in diameter
PON	program opportunity notice
PPE	personnel protective equipment
ppm	part(s) per million
ppmvd	part(s) per million by volume, dry basis
ppmv	part(s) per million by volume
PSD	prevention of significant deterioration
psia	pound(s) per square inch absolute
psig	pound(s) per square inch gauge
PSM	process safety management

PT	potential transformer (electrical)
RDF	refuse derived fuel
RO	reverse osmosis
rpm	revolutions per minute
RSC	radiant syngas cooler
S	sulfur, elemental
SAP	sulfuric acid plant
scf	standard cubic feet (reference state = 60°F and 14.7 psia)
scfm	standard cubic feet per minute
SCR	selective catalytic reduction (for NO _x emission reduction)
SGC	syngas cooler
SO ₂	sulfur dioxide
SO ₃	sulfur trioxide
SO _x	combined sulfur dioxide and sulfur trioxide
SOE	sequence-of-events
SRU	sulfur recovery unit
ST	steam turbine
TCLP	toxicity characteristics leaching procedure
TLV	threshold limit value
TSA	temperature swing absorption
U.S.	United States (of America)
USA	United States of America
UV	ultraviolet
V ₂ O ₅	vanadium pentoxide
VOC	volatile organic compounds
Vol	volume
wt	weight
yr	year(s)

INTRODUCTION

Tampa Electric Company planned, engineered, built, and operates the Polk Power Station Unit #1 Integrated Gasification Combined Cycle (IGCC) Power Plant. The project was partially funded under the Department of Energy's Clean Coal Technology Program pursuant to a Round III award. This document provides the Department of Energy with a comprehensive report of the first 5½ years of operation from first syngas production in July of 1996 through the end of 2001.

Polk Power Station is a nominal 250 MW (net) IGCC power plant, located southeast of Tampa, Florida in Polk County. The power station uses an oxygen-blown, entrained-flow coal gasifier integrated with gas clean-up systems and a highly efficient combined cycle to generate electricity with significantly lower SO₂, NO_x, and particulate emissions than existing coal-fired power plants. This project demonstrates the technical feasibility of commercial-scale IGCC technology.

Tampa Electric Company began taking the Polk Power Station from a concept to a reality in 1989. The project received an award under Round III of the DOE Clean Coal Technology Program in January 1990 based on older gasification and combined cycle technology to be located at a different site. The project concept was soon revised to incorporate newer more efficient gasification and combined cycle technology. Meanwhile, an independent site selection committee consisting of community representatives selected the current site, an abandoned phosphate mine in southwestern Polk County Florida. The DOE Cooperative Agreement was modified in March 1992 to incorporate these improvements. Detailed design began in April 1993, permits were issued without intervention, and site work began in August 1994. The power plant achieved "first fire" of the gasification system on schedule in July 1996. The unit was placed into commercial operation on September 30, 1996. Since that time, the plant has met its objective of generating low-cost electricity in a safe, reliable, and environmentally acceptable manner. On September 30, 2001, Polk Power Station completed its fifth year of commercial operation. Moving forward into 2002, the plant continues to operate base loaded as a key part of Tampa Electric Company's generation fleet. The project has received a number of awards over the years from industrial and civic groups (Appendix E).

This comprehensive report is intended to provide detailed descriptions of the technology and processes used, the impact and resolution of all key issues which arose during the demonstration period, the plant's technical and environmental performance, the economics, and our conclusions and recommendations.

The appendices, particularly Appendices A, B, and C, contain important information to supplement the main body of the report.

- Appendix A is a day-by-day account of the 5 ½ year demonstration period, showing which fuel was being processed and indicating the shutdown cause of all gasifier outages over 12 hours duration.

- Appendix B is an excerpt from the project startup report to DOE covering details of startup activities and issues which arose in 1996, including some which occurred prior to initial operation of the gasifier.
- Appendix C is a listing of the 12 conference papers (roughly 2 per year) presented during the 5 ½ year demonstration period. These provide annual information on the progress of the demonstration. Some of the issues are covered there in more detail than in the body of this report. The entire text of these papers is included in the CD version of the report included with each hard-copy. The CD version is in the Adobe Acrobat PDF format. This necessary Adobe software can be downloaded at no cost from the following web site: www.adobe.com/products/acrobat/.

Tampa Electric Company is an investor-owned electric utility, headquartered in Tampa, Florida. It is the principal, wholly-owned subsidiary of TECO Energy Inc. TECO is an energy-related holding company, heavily involved in the mining, transportation, and utilization of coal. Tampa Electric has about 3650 MW of generating capacity, of which over 97 percent is produced from coal. The company serves over 500,000 customers in an area of approximately 2,000 square miles in West Central Florida, primarily in and around Tampa.

TECO Power Services, another subsidiary of TECO Energy Inc., provided project management services to Polk Power Station during its design, construction, and startup phases. TECO Power Services is currently concentrating on commercializing IGCC technology as part of the Cooperative Agreement with the U.S. Department of Energy. This subsidiary was formed in the late 1980s to take advantage of the opportunities in the non-regulated utility-generation market. It owns and operates natural gas and coal-fired power plants in both North and Central America, as well as in Hawaii. Several other projects are underway in various stages of development in high growth markets in these areas.

EXECUTIVE SUMMARY

The Polk Power Station IGCC Project has successfully met the key objectives of the plant owner/operator and the Department of Energy during its initial 5½ years of operation. Multiple technologies from many different suppliers were fashioned into a highly integrated efficient power generation plant. Synthesis gas fuels an advanced combustion turbine without adverse effects. Multiple coals and other low cost solid feedstocks have been successfully utilized. Very low emissions are being achieved with these "dirty" solid fuels. After overcoming several initial problems, the unit is now demonstrating good availability. The staffing and training approach and the team based organization structure have contributed to the success of the plant.

Figure ES-1 is a general flow diagram of the 250 MW (net) Polk Power Station Unit 1 IGCC Plant. Its main elements are identified and briefly discussed below.

Air Separation Plant

The air separation unit (ASU) cryogenically separates ambient air into its major constituents, oxygen (O₂) and nitrogen (N₂). Most of the O₂ (approximately 2175 tons per day at 96% purity) is needed in the gasification plant for the production of fuel gas. 2.5% of the available O₂ is used in the sulfuric acid plant. Most of the N₂ goes to the power plant's combustion turbine to dilute the fuel gas for NO_x abatement. This diluent N₂ also increases the combustion turbine's power production by 15% (25 MW) as it expands through the turbine. The gasification plant and power plant use a very small portion of the N₂ for purges and seals.

Major availability impacts attributable to the ASU resulted from 2 incidents, both of which have been resolved:

- Faulty field welds on the instrument tray support arms attached to support pads on the outside of the distillation column in 2000
- Failure of the main air compressor 4th stage impeller in 2001.

Gasification Plant

The gasification plant produces clean medium BTU fuel gas and high pressure steam for electricity production from 2500 tons per day of coal or other solid fuel such as petroleum coke and biomass. Major subsections of the gasification plant are:

- Coal receiving and storage
- Slurry preparation
- Gasification and high temperature heat recovery
- Slag, fines, brine, and process water handling
- Gas cleaning
- Sulfur recovery (sulfuric acid plant)

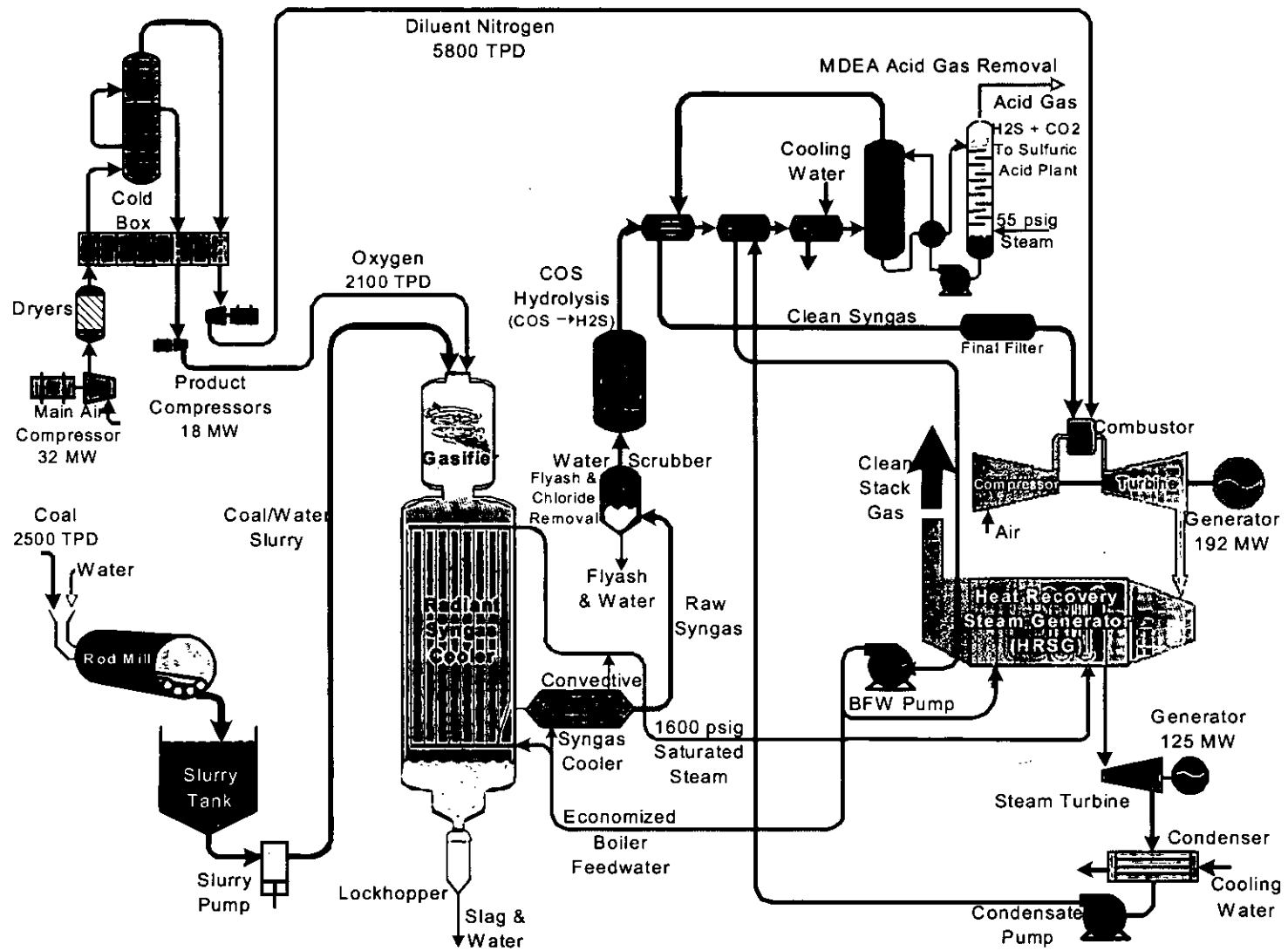


Figure ES-1 Overall Flow Diagram

Coal from the 2 silos on-site is mixed with recycled water plus fines and ground into a viscous slurry which is pumped to the gasifier. The gasifier is a Texaco slurry fed, O₂ blown, entrained gasifier operating between 2400°F and 2700°F. High pressure steam is produced by cooling the syngas in a radiant syngas cooler and then 2 parallel fire tube convective syngas coolers. Particulates are removed in an intensive water scrubbing step. A sulfur compound, carbonyl sulfide, is converted to hydrogen sulfide which can be more easily removed from the syngas. The gas is then further cooled in a way that almost all of the remaining heat is recovered by preheating the clean syngas fuel and boiler feedwater. Finally, the sulfur is removed from the gas by a circulating amine (MDEA) solution, and the clean gas is reheated, filtered, and delivered to the combustion turbine. The sulfur removed from the syngas is sent to the sulfur recovery system which generates medium pressure steam and produces 200 tons per day of 98% sulfuric acid for the local market. Fines containing the unconverted carbon from gasification are separated from the slag and water and are recycled to the slurry preparation section. The slag is being marketed.

The gasifier requires a 20 to 30 day planned outage every other year to replace its refractory liner, and annual outages of slightly shorter duration to inspect the liner and make minor repairs. Major unanticipated adverse availability impacts originating in the gasification plant were:

- Combustion turbine damage from failure of raw/clean gas exchanger tubes in 1997. The exchangers were removed, but a slight heat rate penalty endures.
- The convective syngas coolers experience pluggage similar to that which caused failure of the raw/clean gas exchangers. We were able to modify these exchangers to significantly reduce the impact of this plugging to the point that most cleaning can be done during outages due to other reasons.
- The gasifier generates twice as much carbonyl sulfide as expected, and several forced outages occurred in the course of dealing with it. The issue has been largely resolved with the installation of a COS hydrolysis system and an ion exchange unit to remove undesirable by-products of COS hydrolysis from the MDEA solvent.
- Different types of seals protect the Radiant Syngas Cooler shell from hot syngas. Failure of one of them during early operation forced an extended outage. Subsequent availability impacts have been minimal.

The quantity of unconverted carbon from the gasifier has been twice as much as expected. This has not had a significant impact on availability, but it has resulted in significant capital and O&M costs in the slag, fines and water subsections and a heat rate penalty. The current approach to mitigating the effects of this poor carbon conversion is to separate the marketable slag from this unconverted carbon and recycle as much of it as possible to the gasifier.

Dissolved solids are removed from the process water in a brine concentration unit so the water can be recycled, eliminating any process water discharge. Polk's brine

concentration system design was based on laboratory scale testing. O&M costs have been much higher than expected. Several expensive capital improvements have been required, and more renovation is in progress and planned. Fortunately, there have been no station reliability impacts.

Power Block

The power block is a General Electric combined cycle, slightly modified for IGCC. The combustion turbine is a GE 7FA which generates 192 MW on fuel gas plus diluent N₂ or 160 MW on distillate fuel. A heat recovery steam generator (HRSG) uses the 1065°F combustion turbine exhaust gas to:

- Preheat boiler feedwater, much of which is sent to the gasification plant,
- Generate about 1/3 of the plant's high pressure steam (2/3 comes from the gasification plant's high temperature heat recovery section),
- Generate low pressure steam for the gasification plant, and
- Superheat and reheat all the plant's steam for the steam turbine.

The steam turbine's inlet throttle steam conditions are 1450 psig and 1000°F with 1000°F reheat inlet temperature. It nominally produces 123 MW.

The gross power production is typically 315 MW (192-CT and 123-ST). The oxygen plant consumes 55 MW, and other auxiliaries require 10 MW, so the net power delivered to the grid is 250 MW.

The combustion turbine requires an annual 10 day planned outage to inspect the combustion hardware, and longer planned outages at less frequent intervals to inspect all the hot gas path equipment. The combustion turbine's distillate fuel system has been a significant cause of unplanned outages. Most of these problems have been eliminated, but some are still being addressed.

Utility and Common Systems

In addition to the three main sections identified above, Polk also has several utility and common systems based on relatively standard designs:

- Electrical Distribution
- Control and Data Acquisition
- Distillate Fuel and Propane - Storage and Distribution
- Auxiliary Boiler
- Flare
- Instrument and Plant Air
- Several Water Systems (Cooling Water, Boiler Feed Water, etc.)

These systems have not had a significant adverse availability impact.

Availability

The gasifier has been in service an average of 70% of the time during the last 4 years as can be seen by the gasifier on stream factor in Figure ES-2. The on-stream factor increased steadily through 2000, the station's best year, but the 2001 results were disappointing due to three lengthy outages, only one of which was planned. We expect the 80% gasifier on stream factor achieved in 2000 is more typical.

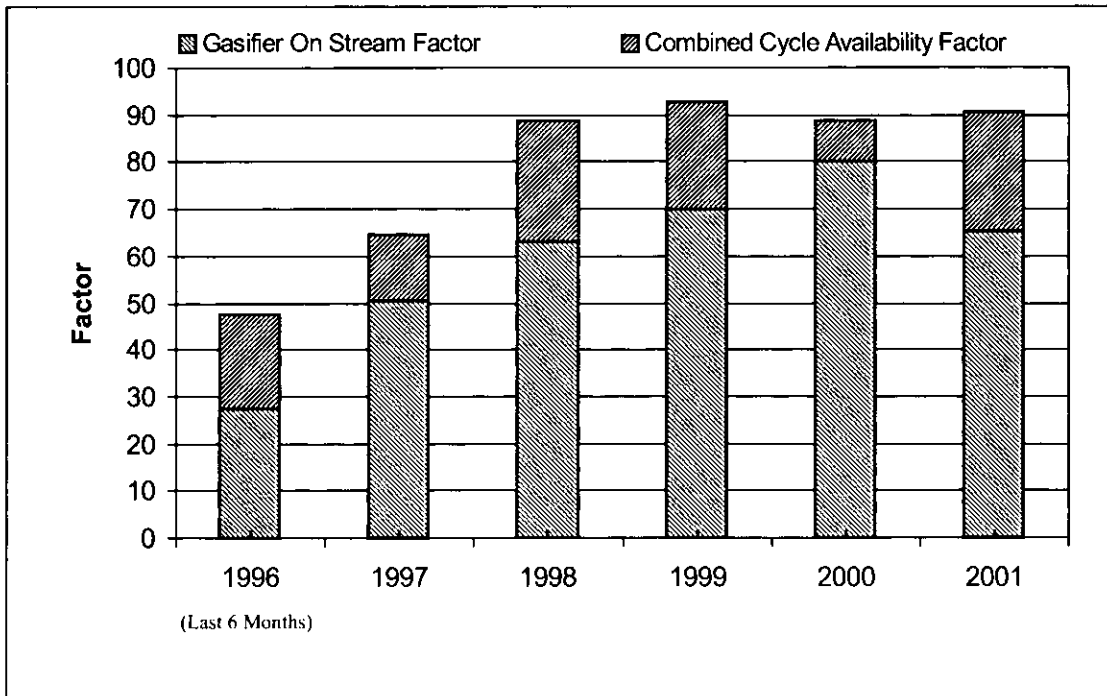


Figure ES-2 Availability

One significant advantage of IGCC systems is that even when the gasifier is out of service, the combined cycle is still available most of the time when needed. The combined cycle was available for operation on either syngas or distillate fuel 90% of the time from 1998 through 2001 as can be seen by the combined cycle availability factor in Figure ES-2. Its availability during periods of peak demand was even higher as discussed in Chapter 2.

Air Emissions and Fuel Flexibility

Low air emissions from low cost, high sulfur feedstocks is IGCC's main driver. The systems at Polk recover over 97% of the sulfur released from the current fuel, a very low-cost 50% blend of high sulfur petroleum coke with coal. The facility has successfully processed over 20 fuels and fuel blends, including one blend containing some biomass. SO_x emissions were consistently low across this spectrum. NO_x emissions were likewise lower than those from other coal-fired power plants, averaging 0.7 lb/MWh or 0.07 lb/MMBtu for the last three years. IGCC particulate emissions are especially low at 0.04 lb/MWh or 0.004 lb/MMBtu. SO_x and particulates are easier to remove in IGCC than in conventional coal combustion systems since the pollutants are more concentrated where

they are removed from IGCC's much smaller fuel gas stream than from the flue gas generated by total combustion. These same factors which facilitate removal of conventional pollutants such as SO_x and particulates will give IGCC an added advantage if removal of trace elements such as mercury is required in the future. Polk has an operating heat rate of 9650 Btu/kWh which is better than most conventional coal fired plants, and other IGCC's are even more efficient. This gives IGCC an advantage over the other coal fired technologies with regard to CO₂ emissions at the present time. Should CO₂ capture and sequestration ever be required in the future, there is almost universal agreement that IGCC would be the most suitable solid fuel fired technology.

Outlook

Visitors acknowledge that IGCC systems have lower emissions and higher cycle efficiency than other coal fired power generation systems. However, they frequently cite the high initial cost of IGCC, especially relative to natural gas fired combined cycles, and sometimes relative to other coal-fired plants, as its major drawback. Today's direct cost for a new single train 250 MW IGCC plant on the Polk site in Polk's current configuration incorporating all the lessons learned would be about \$1650/kW (Chapter 4). Higher reliability and lower emissions can be provided for relatively little incremental cost in a new facility. Nevertheless, \$1650/kW does indeed seem expensive compared to some other systems under consideration. There are several well known approaches to lowering costs that are applicable to today's first generation IGCC plants. Among them are:

- Economies of scale (especially in the common or balance-of-plant systems)
- Technical improvement (modest or maybe even revolutionary), and
- Replication of proven configurations to eliminate costly reinvention.

Application of these cost-cutting approaches could reduce capital costs by up to 20%, possibly lowering direct costs to \$1300/kW.

Besides lower costs, there are many highly probable scenarios which would provide impetus for widespread adoption of IGCC. The most likely are:

- A lasting change in the expected availability and relative price of natural gas,
- Additional environmental legislation requiring mercury and or CO₂ removal, and
- Economic stability allowing potential users to take a longer term investment view.

Given the very good performance of this first generation of IGCC plants, and with continued encouragement and support from DOE, demonstrated lower costs, and other favorable economic and social trends, it appears that the future of IGCC is very bright.

CHAPTER 1 - PROCESS DESCRIPTION AND ISSUES

1.1 CHAPTER ORGANIZATION

The main focus of this chapter is to provide a process description of each major subsection of the plant and to identify and quantify all associated adverse availability impacts. This chapter also addresses other key issues for each subsection which have not forced outages but which have had other significant adverse impacts such as high costs, forced load reductions, efficiency losses, or safety concerns. Finally, a brief overview of startup and operation of each subsystem is provided and some of the unique safety issues are identified.

This chapter is divided according to the four main sections of the plant:

- Air Separation Plant (ASU)
- Gasification
- Power Block
- Utilities and Common Systems

The main plant sections are generally divided into subsystems. Each subsection addresses the following topics:

- General Information (licensor, major manufacturers, etc.)
- Detailed Process Description
- Startup and Operation
- Special Safety Issues
- Resolved Availability Issues
- Unresolved Availability Issues
- Other Key Issues

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1.2 AIR SEPARATION UNIT (ASU)

1.2.1 GENERAL INFORMATION

Figure 1-1 is a general flow diagram of the Air Separation Unit (ASU) which produces nominally 2100 tons/day of oxygen at 96% purity and 6000 tons/day of nitrogen at 98.5% purity. Air Products and Chemicals, Inc. (APCI) supplied the ASU on a turnkey basis. APCI fabricated much of the cold box equipment and considers its design and internal stream data proprietary. All compressors were manufactured by Mannesmann DEMAG.

1.2.2 PROCESS DESCRIPTION

The Main Air Compressor (MAC) supplies nominally 11,500 KSCFH of air at full plant load. It is a four stage compressor with intercooling between each stage and an aftercooler. Plant controls automatically throttle the MAC's inlet guide vanes to supply just enough air for the ASU to meet the gasifier's oxygen requirements. Its 13.8 kV, 45,000 HP motor draws 34 MW at full load. Special provisions had to be made for startup of this motor.

From the MAC discharge, the air first goes to the Temperature Swing Absorption (TSA) system for removal of water vapor and traces of CO₂. Otherwise, the H₂O and CO₂ would freeze in the cryogenic equipment, forming ice which would cause plugging. The Polk TSA is a four bed system with two beds always drying and two beds regenerating, one heating and the other cooling. Regeneration is done with dry nitrogen drawn from the main nitrogen product stream.

The air then enters the cryogenic section of the plant through the main heat exchanger, where it is cooled by the main product streams: dilute nitrogen (DGAN), gaseous oxygen (GOX), and high purity gaseous nitrogen (HPGAN). A compressor/expander (Compander) provides refrigeration for the system. Cryogenic distillation occurs in a standard two column arrangement, one column operating at elevated pressure, the other at reduced pressure.

DGAN is the largest product stream. It normally contains about 1.5% oxygen, comfortably and consistently below the required 2% maximum. After the DGAN leaves the main exchanger, 35 KSCFH is extracted for purging and blanketing in the gasification plant. Additional DGAN is drawn off for regeneration of the TSA, but this is later returned to the main DGAN stream to maximize DGAN recovery. A pressure controlled vent at the suction of the DGAN compressor releases a small amount of excess DGAN. This is necessary for process control and stability of column pressure. The DGAN compressor then delivers nominally 6,400 KSCFH to the combustion turbine for NO_x abatement and power augmentation at 280 psig and 375°F. The four stage DGAN compressor has one intercooler and no aftercooler. Its 13.8 kV, 22,000 HP motor draws 14 MW.

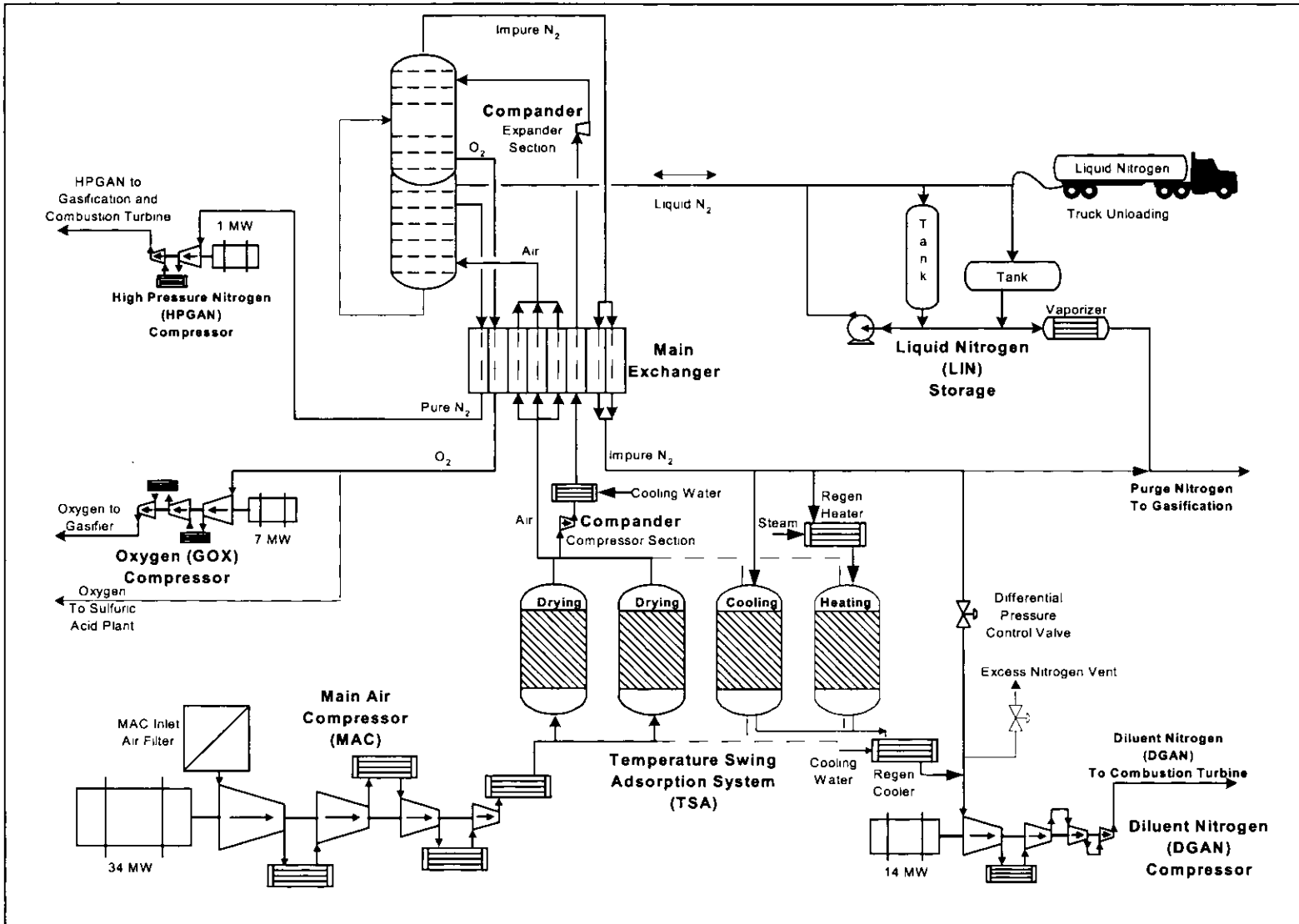


Figure 1-1 ASU Flow Diagram

The main GOX stream, 2,150 KSCFH at full load, is compressed for the gasifier. The GOX compressor is a 6 stage machine with 2 intercoolers, and a recycle cooler, but no aftercooler. Discharge conditions are 580 psig and 270°F. Its 13.8 kV, 9,500 HP motor draws 6.5 MW. 50 KSCFH of GOX from the main exchanger is sent directly to the Sulfuric Acid Plant at ambient temperature without compression.

250 KSCFH of HPGAN (50 ppm O₂) is continually withdrawn for purges and pads in the power block's fuel transfer system and for purges, pads, and sootblowing in the gasification plant. The four stage HPGAN compressor with one intercooler, and a recycle cooler, but no aftercooler delivers N₂ at 830 psig and 400°F. Its 1,750 HP, 4160 V motor normally draws 1.1 MW.

The plant also produces a small stream of liquid nitrogen (LIN) to fill the 2 LIN storage tanks whose total capacity is 41,000 gal. This LIN is used during ASU outages to supply low pressure purge nitrogen to the gasification plant for safety. It is also pumped into the columns for faster ASU plant startup. A LIN truck unloading facility is also included to recharge the LIN tanks during extended ASU outages.

1.2.3 STARTUP AND OPERATION

Polk's process specialists operate and maintain the ASU. APCI provided considerable training prior to initial startup. Also a high fidelity model of the ASU was included in the operator training simulator which was used extensively for operator training prior to initial plant startup.

Cool-down and startup of the ASU from a warm condition requires at least 84,000 gallons of LIN and takes about 36 hours. Following outages of a few days duration, the cryogenic portion of the plant is kept cold and liquid is left in the columns. Startup under those conditions takes from 8 to 12 hours and requires from 14,000 to 28,000 gallons of LIN. If the main air compressor has simply tripped and can be immediately restarted, the ASU can be ready to supply GOX to the gasifier within 4 hours.

1.2.4 SAFETY

Fluids at cryogenic temperatures pose an obvious freezing hazard on contact.

Nitrogen presents a suffocation hazard. Confined space entry procedures must be strictly adhered to for all enclosures and vessels into which nitrogen can settle or leak. Cold nitrogen vapor escaping from the cryogenic portion of the plant might settle into pits and ditches, where nitrogen at ambient temperature might not otherwise accumulate.

Pure oxygen poses an extreme flammability hazard. Cleanliness is critical, and selection of appropriate materials for maintenance such as gaskets, lubricants, and cleaning fluids requires constant vigilance. Any leak must be taken very seriously. Owners/operators must contact the experts any time questions or problems arise.

1.2.5 RESOLVED AVAILABILITY ISSUES

1.2.5.1 MAC 4th Stage Impeller May/June 2001, 27.7 Days

The MAC was being restarted following a 4 day gasification plant maintenance outage. The 4th stage vibration became excessive as the machine was loaded. Partial disbondment was found in the brazed joint between impeller cover and impeller wheel. Vibration levels in this stage had been increasing for a couple of years which may have been partially due to progressing disbondment. Since the vibration was not excessive, we believed it to be due to accumulation of minor deposits. Although the root cause of the failure was not definitively identified, any one or a combination of the following three factors appear to have caused the problem:

- The impeller joints were brazed, not welded. Some experts felt brazing was not as good an assembly technique, because brazing was more subject to corrosive attack. Sulfate and chloride corrosion products were found in the compressor piping and volute, and the disbonded area visually appeared to have experienced some corrosion. The impeller repair was by welding, not brazing. Only the 4th stage impeller had been brazed.
- The piping configuration was such that condensation accumulated in the 4th stage volute during extended outages. Leaving the impeller partially submerged for long periods of time and then starting the machine with the impeller partially submerged could have been damaging. A volute drain was added and draining requirements have been included in the startup procedures.
- It is possible that the upstream intercooler and/or downstream aftercooler might not have been properly drained when the machine was started, leading to excessive water carryover or drain back into the 4th stage. The startup procedures have been modified to assure proper draining of the coolers.

1.2.5.2 Low Pressure Column Level Tap March 2000, 16.7 Days

During operation, instrument tubing failed on a low pressure column level tap, causing an oxygen leak. This tubing was one of several tubing runs secured to a tray. The tray extended the entire height of the column and was connected to the column via support arms welded to pads on the column. The field welds on the tray supports had failed, causing the tray to move. This placed stress on the tubing, causing it to break at the location of the low pressure column tap. The problem was resolved through an excellent cooperative effort between APCI and Tampa Electric. Inspections revealed numerous bad tray support welds as well as inferior welds of the process piping supports. Specialized equipment and personnel removed all the insulation (perlite) to facilitate the repairs. Besides simply repairing the welds, the

instrument tubing support tray was repositioned further away from the column can wall (the metal containment for the insulation around the column) to ensure that the tray maintained clearance from the can wall under all conditions.

1.2.5.3 GOX Compressor Suction Line Brittle Failure
March 1997, 9.7 Days

Cryogenic oxygen made its way into the carbon steel GOX compressor suction line during startup. The line failed by brittle fracture due to high localized stresses resulting from pipeline contraction due to the cryogenic temperatures. The complex protective logic in the plant's distributed control system (DCS), intended to prevent such incidents, was found to have been at fault and was corrected.

1.2.5.4 Minor Voltage Swings
3 Incidents: November 1996 (2), September 1997; 3.9 Days Total

On three occasions during very early plant operation, minor transmission system voltage swings caused trips of either the MAC or the GOX compressor, resulting in gasifier trips. Improvements were made in the protective circuitry, and such minor disturbances no longer cause ASU problems.

1.2.5.5 MAC Guide Vanes
2 Incidents: March 1998, January 1999; 3.6 Days Total

A malfunctioning MAC inlet guide vane controller caused one forced outage and one startup delay. The guide vane controllers for all the ASU compressors were eventually upgraded.

1.2.5.6 TSA Cycle Interruption
April 2001, 2.8 Days

A DCS card failed, causing an interruption in the TSA bed switching sequence during a plant startup. This led to a breakthrough of CO₂ from the dryers into the cryogenic portion of the ASU, forming an ice deposit. The plant had to be shut down and derimed (defrosted). Alarming of TSA sequence problems has been upgraded.

1.2.5.7 GOX Intercooler Gasket
3 Incidents, 2.4 Days Total
January 1998, January 1999, February 2000

A leaking gasket assembly on the GOX compressor intercooler caused 3 startup delays. High torsion stresses were being placed on the exchanger's channel head as a result of construction errors made in adjusting the exchanger's spring supports. The gasket was also flimsy and hard to install. The pipe supports were adjusted and the exchanger head was machined to flatten distortion created by the high stresses and so that an o-ring could be installed. No subsequent leaks have occurred on this exchanger.

1.2.5.8 GOX Compressor Discharge Silencer
1 Startup Delay: December 1996, 8 Hours

Failure of the GOX compressor discharge silencer caused an 8 hour startup delay while we confirmed that it was safe to operate without it until it could be replaced. A temporary non-silenced vent was installed so that the unit could continue to operate. It was found that the silencer-vent had already been repaired during the original start-up. The original vent was poorly designed, and the expansion was fixed at the top instead at the bottom of the vent. A more robust design, as suggested by the plant engineer, was discussed and implemented with the OEM. The design change was incorporated to the original vent, and the vent was reinstalled during the next outage. No further vent problems have occurred.

1.2.5.9 Low LIN Inventory
1 Startup Delay: July 1998, 15 Hours

Low liquid nitrogen (LIN) inventory delayed a startup for 15 hours. LIN ordering procedures were immediately streamlined.

1.2.6 UNRESOLVED AVAILABILITY ISSUES

1.2.6.1 Spurious Trips From Instrumentation/Control Component Failures
8 Incidents Over 5½ Years, 7½ Days Total Forced Outage Time

Considerable redundancy was incorporated into the original instrumentation and control system design of the ASU. Nevertheless, eight gasifier trips costing a total of 7½ days of unavailability have occurred over Polk's 5½ years of operation. Their frequency has decreased slightly since we have solved some generic problems with certain transmitter types, and their impact has certainly decreased since we can now recover from most in 4 to 6 hours with a hot restart of the gasifier. Nevertheless, we can expect continued problems of this type now that the original instruments are aging. The only known solution which would significantly reduce this problem is a back-up oxygen supply system, but these relatively few days of unavailability could never justify that cost. That was the conclusion we reached in the initial plant design phase, and five years of operation have proven it correct for Polk's economic situation. Other facilities with greater penalties for unavailability might reach a different conclusion.

1.2.7 OTHER ISSUES

1.2.7.1 MAC Capacity/MAC Aftercooler Pluggage

Figure 1-2 illustrates two important points:

- The MAC initially exceeded its design capacity of 10,600 KSCFH at 85°F ambient temperature. But even then the MAC did not have the capability to deliver enough air to meet the total oxygen requirements of the gasifier. This is due to the gasifier's lower than anticipated carbon conversion and the resulting need to recycle the unconverted fines as well as TECO's desire to process lower quality fuels. The rest of the ASU (cryogenic separation section, GOX compressor, etc.) is adequate to supply those needs based on tests at lower ambient temperature when the MAC capacity was available.
- Although the MAC could almost meet the gasifier's needs initially, its capacity has deteriorated significantly over the 5½ years of operation.

Not shown on the graph is the fact that as the ambient temperature increases to the average summer daily peak of 91°F (when TECO needs the power the most), the MAC's capacity falls another 1.5%. The shortfall worsens as the peak ambient temperature increases even further during the really hot spells each summer.

Part of the capacity loss is due to pluggage of the MAC aftercooler, evidenced by its increased pressure drop and deteriorating heat transfer effectiveness over the years. The higher aftercooler pressure drop increases the head the MAC must develop, causing a downward shift in the flow capability on its operating curve. The aftercooler tubes are finned and rust particles are visibly obscuring the gas path between the fins. The source of the rust particles is probably the carbon steel piping and intercooler shells. Since Polk's ASU shuts down and restarts much more often than most commercial ASUs, rust particles have a better opportunity to form and spall.

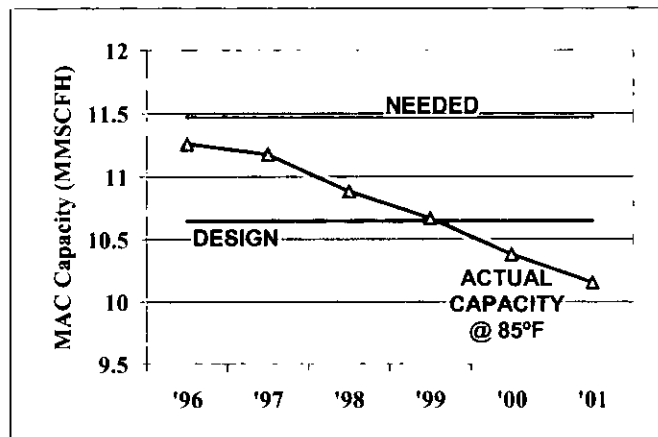


Figure 1-2 MAC Capacity

In addition to the backpressure, the aftercooler pluggage has resulted in deteriorating heat transfer effectiveness over time. Cooling water side fouling has also periodically reduced the heat transfer rate (See Section 1.5.9.5.4.1). Reduced aftercooler heat transfer effectiveness has had another detrimental impact. The resulting higher aftercooler outlet temperatures cause more water vapor to enter the TSA beds. This overloads them, causing breakthroughs. Fortunately, APCI had the foresight to design the TSA regeneration heater for higher than specified steam pressure. Higher pressure/temperature steam was supplied to the heater which so far has enabled us to adjust the TSA cycle to accommodate the higher water vapor loading.

Attempts to clean the aftercooler have failed. A new tube bundle is scheduled for delivery in early 2002, and all the carbon steel piping and intercooler shells, which we believe were the source of the rust which plugged the old bundle, have been coated with rust-proofing. Inspections have shown this coating to be effective.

The aftercooler plugging does not explain all of the observed MAC performance deterioration. The compressor manufacturer, Demag, and APCI are helping to identify the cause of the remaining capacity loss. The data suggest that it is related to malfunctioning inlet guide vanes, but as of January 2002, testing and inspections have failed to identify any specific problem. Even if it had and we could restore and keep the MAC at its "as new" performance, it would not accommodate the shortfall in initial design capacity. Consequently, Polk is investigating other options. Among the promising options is to install a supplemental air compressor, more counter-rotated guide vanes, or a "supercharger" to satisfy all air requirements.

NOTE: After completion of the Period of Performance under the Cooperative Agreement and following distribution of the initial draft of this report, a MAC guide vane defect was identified and corrected. This restored the MAC capacity to slightly above the design point. Approaches to providing additional air to satisfy the gasifier's total oxygen requirement are still under consideration.

1.3 GASIFICATION PLANT

1.3.1 GENERAL

The gasification plant consists of all facilities needed to produce a clean fuel gas from coal (except the oxygen supply and the utility/common systems) and to produce transportable by-products or waste products. It consists of the following six important subsystems:

- Coal Receiving and Storage
- Slurry Preparation, Storage, and Delivery
- Gasification and High Temperature Heat Recovery
- Slag, Fines, Brine, and Process Water
- Gas Cleaning, Cooling, and Reheating
- Sulfur Recovery (Sulfuric Acid Plant)

The coal gasification technology was licensed from Texaco Development Corp. Texaco provided the process design, and Bechtel provided the detailed engineering and construction management for all of these subsystems except the Sulfuric Acid Plant. Monsanto Enviro-Chem Systems, Inc., provided the Sulfuric Acid Plant on a turnkey basis.

1.3.2 COAL RECEIVING AND STORAGE

1.3.2.1 PROCESS DESCRIPTION

Coal is received by barge at Tampa Electric Company's Big Bend Station coal yard, where most of Polk's inventory is maintained. Polk's coal is loaded into trucks at Big Bend and weighed at a new transloading facility which was constructed as part of the project. The coal is typically delivered in covered, bottom-dump tandem trailers, each with a 26-ton payload; 95 trucks per day are required at full operating rate. At Polk, the trucks off-load into an above-grade unloading hopper in a covered unloading structure. Dust suppression sprays at the top of the hopper control dust emissions if the coal is dry and dusty. Belt feeders transfer coal from the hopper outlets onto an enclosed unloading conveyor.

The single 400 tph unloading conveyor transports coal from the unloading structure into one of the two 5000 ton storage silos. A diverter gate and a silo feed conveyor provide feed to the second, adjacent silo. A dust collection system at the top of the silos catches dust at the conveyor/feeder/silo transfer points. Each silo is equipped with a 400 tph reclaim feeder and reclaim conveyor to deliver the coal to the 200 ton surge bin at the top of the coal grinding structure.

1.3.2.2 STARTUP AND OPERATION

Trucks are received 24 hours per day, 7 days per week. However, delivery rates are somewhat reduced on weekends, so silo inventory is often depleted. Some coal is almost always kept in each silo, since totally emptying a silo invariably results in some poor quality fuel from the very bottom for a period of time, leading to upsets in slurry preparation and gasification. The reclaim system from the silos is set up to automatically top off the surge bin from alternating silos.

We have utilized various strategies when changing fuels or running a test fuel. When we know we will be conducting a relatively short term test, we maintain an inventory of our base fuel in one silo (in case the test fuel poses problems) and then empty or almost empty the other. We then begin receiving the test fuel into the empty silo and withdrawing exclusively from it.

1.3.2.3 SAFETY

Most of the safety considerations in this area are those normally associated with rapidly moving conveyors and coal dust. A CO detection system monitors the silos for heating and smoldering coal, which has occurred on a few occasions. An inert gas injection system (purge nitrogen) is used during long outages.

1.3.2.4 AVAILABILITY ISSUES

No problems have occurred to cause lost availability or derating due to failures in this area of the plant.

1.3.2.5 OTHER ISSUES

1.3.2.5.1 Belt Alignment

Belt alignment has occasionally been a problem causing brief interruptions in coal deliveries. Misalignment was primarily due to chemical attack causing premature curling. Curling has been observed in many belts at the plant, although in most cases it is not severe enough to require replacement after 5 years of operation. The unloading conveyor belt was replaced in 2001 with a material which is more resistant to chemical attack. On-going inspections show that the material change appears to work satisfactory.

1.3.2.5.2 Silo Level Measurement

One of the more frustrating aspects of this section of the plant is the inability to measure the silo coal inventory more accurately than $\pm 20\%$. This is particularly troublesome when inventories are low early in the week, or when truck deliveries have been interrupted due to bad weather.

1.3.2.5.3 Fuel Blending and Fluxing

When using petroleum coke blends, best results have been achieved with a three-component blend consisting of a large fraction (55%-60%) of petroleum coke and smaller fractions of other coals in a specific ratio to optimize ash characteristics and sulfur content of the blend. Producing such blends remotely in the proper proportions and shipping them to Polk without segregation during handling or in storage is a challenge. If higher concentrations of pet coke are to be processed, consideration will be given to adding on-site blending or flux addition facilities to this section of the plant.

1.3.3 SLURRY PREPARATION

1.3.3.1 PROCESS DESCRIPTION

The slurry preparation system consists of two independent grinding trains, each of which can process up to 120 KPPH or 1440 tpd of coal (as received basis), which is between 55% and 60% of the gasifier's requirement at full load.

For each train a weigh feeder meters the coal into the rod mill. The rod mill is also fed with recycled process water containing recycled fines. Additives to reduce the viscosity of the slurry and/or adjust its pH may also be fed into the mills. The mills rotate at a fixed speed and contain steel rods, which crush the coal particles, producing the viscous slurry. A coarse trommel screen at the discharge end of each mill rejects broken rod parts. The slurry itself easily passes through the openings in the trommel screen and falls into an agitated mill discharge tank. From there, a centrifugal pump delivers the slurry to a finer screen at the top of a large run tank. This screen removes any metal or coal particles large enough to be troublesome to the main slurry feed pump which delivers the slurry to the gasifier. A density meter on the discharge line of the centrifugal pump provides a continuous indication of slurry concentration, which is normally maintained between 62% and 68% solids.

Slurry storage consists of two agitated run tanks, each of which can provide 4 hours of base load operation when completely full. An air injection system is available for sparging each tank in the event of agitator failure. The tanks together can provide almost 8 hours of full load gasifier operation when they are full. The slurry flows by gravity from the bottom of either or both tanks to the suction of the gasifier feed pump. A common transfer pump can draw slurry from either tank and deliver it to the other tank or to circulate a tank on itself to insure homogeneity.

The slurry feed system is a single three cylinder Geho diaphragm pump with a variable frequency drive. It can deliver up to 500 gpm of slurry at 500 psig to the gasifier atop the main structure. A density meter on its discharge line provides a continuous indication of the concentration of the slurry going to the gasifier.

The slurry sump is an important part of the process. Whenever a slurry system is shut down, the lines and equipment must be drained and flushed into the slurry

sump. The sump is agitated and sparged. Water and solids from this sump are returned to the mills.

1.3.3.2 STARTUP AND OPERATION

The run tanks provide sufficient surge capacity and the mills have enough make-up capability that the gasifier has never been forced down due to low slurry inventory. However, because the mills are out of service regularly for relatively short periods and the run tanks have been unavailable occasionally for extended periods, this has required some careful planning at times.

An isolated run tank containing slurry will heat up from continual agitation (which must be maintained). This heat can damage the tank liner. Also, some of the water will evaporate, possibly producing slurry which is too thick to pump. Cool water must, therefore, be added whenever the plant is down for any length of time. Also, during normal operation, each mill feeds a separate run tank, and the transfer pump moves the slurry to the tank that is feeding the Geho pump. This way, both tanks contain an active inventory.

The mill's rods are made of softer steel than their liners, so the rods, not the liners, gradually wear away. Consequently, rods must be added about once per week. This requires shutting down the mill for an hour or two. The mill discharge pumps must also be changed out every two to three months, an operation that requires two to three hours.

The density meters provide a good indication of trends in slurry concentration, but they must be "calibrated" daily to maintain absolute accuracy. More frequent calibration is required if the relative quantity of recycle fines varies significantly.

1.3.3.3 SAFETY

It is extremely important that no purge water be allowed to enter the slurry during gasifier operation. Since the slurry flow is controlled volumetrically, diluting the slurry with purge water would cause a higher oxygen to fuel ratio in the gasifier which could lead to a severe high temperature excursion. Other than that, there are no special safety considerations in the slurry area other than those associated with large rotating machinery and coal dust around the weigh feeders.

1.3.3.4 RESOLVED AVAILABILITY ISSUES

1.3.3.4.1 Erosion/ Corrosion

5 Forced Outages Totaling 3.8 Days, Mostly in 1997 and 1998

The relatively little forced outage time directly attributable to erosion/corrosion belies the severity of the problem that was pervasive throughout the slurry system. The following were the steps that were taken. Although erosion/corrosion is never completely solved, these steps have reduced it to a very manageable and affordable level.

Mill Discharge Pumps. These pumps were originally Moyno progressive cavity pumps with a hard faced rotor and soft stator costing about \$50,000 each. Although these pumps have provided satisfactory service in slurry service at some plants, their parts life here was only 2 or 3 months. Replacement parts were extremely expensive, and repair time was 1 to 3 shifts. The Moyno pumps were replaced with simple centrifugal pumps. The new pumps didn't last any longer, but cost less than \$5,000 each and could be completely changed out in 2 to 3 hours.

Slurry Feed Pump. The gasifier's slurry feed pump was supplied by Geho. The internal metal parts in contact with the slurry were originally carbon steel which typically provided only about 30 days life. Changing to corrosion resistant steel has tripled the parts life. The valve housings were also made of carbon steel, which had an accelerated wear rate of 1/8 of an inch per month. An epoxy coating has provided effective corrosion control for the valve housings.

Piping. Walls of the carbon steel pipe thinned at a rate of up to 100 mills/year at direction changes and branch connections. The entire low pressure carbon steel piping system was replaced with HDPE pipe. All direction changes and branches on the high pressure were overlaid with erosion/corrosion resistant material.

Run Tank Walls. The run tanks were made of carbon steel, and wall thinning was unacceptably high. A rubber liner was applied which arrested the erosion/corrosion. Rubber lining does have its drawbacks: it is somewhat expensive, takes time to apply and cure, limits the tank operating temperature, and requires particular care during maintenance.

Agitator Blades. The agitator blades were originally carbon steel with a hardened overlay material on the leading edges. These failed rapidly. Rubber coating was applied to increase the life of both the shaft and blades. This has been effective, but at least annual inspections and repair most of the time are required to maintain equipment reliability.

1.3.3.4.2 Slurry Screen Failure and Repair 5 Forced Outages Totaling 51 Hours in November 1999 Through January 2000

We experienced several failures of the slurry screens during early operation. The screens were upgraded, and failures have been much less common. However, in late 1999, a screen failure was undetected long enough for some foreign material to enter the run tank. To compound the problem, some fasteners were dropped into the run tank during the screen repair. The other run tank was out of service for rubber lining at the time. Maintenance procedures have been modified.

1.3.3.5 UNRESOLVED AVAILABILITY ISSUES

1.3.3.5.1 Slurry Feed Pump Spurious Trips 7 Forced Outages Totaling 75 Hours

The slurry feed pump will occasionally trip or simply stop running. Often the cause can be identified (line voltage swing, failed microswitch, etc.) but sometimes it cannot. We address each identified problem and are adding a reliable first out indication to help identify the mysterious events. As with the spurious trips of the Air Separation Plant, we are now able to recover with a hot restart of the gasifier in almost all cases, so the net impact on availability is now minimal. As the plant instrumentation ages, we can expect continuing spurious trips of this nature. The only action which would significantly reduce the incidence of such trips would be to install and continuously operate a parallel slurry feed pump. This was the approach used at Cool Water, a similar IGCC plant using the same Texaco gasification technology operated in the early 1980's. However, the net impact of these trips on overall plant availability is so low that the cost of a parallel operating pump could not be justified at Polk. Other facilities where availability has a higher value might reach a different conclusion.

1.3.3.5.2 Slurry Feed Pump Suction Line Restriction 7 Forced Outages Totaling 150 Hours

The gasifier has automatically tripped on 7 occasions due to lack of sufficient slurry flow which has been traced to either partial or complete blockage of the slurry feed pump suction line. These blockages appear to be due to agglomerates of hardened dewatered slurry from the walls of the run tank or the pump suction line itself. Slurries made from some fuels are more troublesome in this regard than others. One alternative under consideration is to streamline the suction piping which now contains about a 50 foot horizontal run. Another more expensive alternative is to provide a continuous flow past the suction with a low head high throughput centrifugal pump located immediately at the run tank outlet nozzle. Although these incidents are very annoying (the most recent was on Christmas day in 2001), the gasifier has been returned to service in less than 8 hours every time except the first, so the net impact on plant availability is slight.

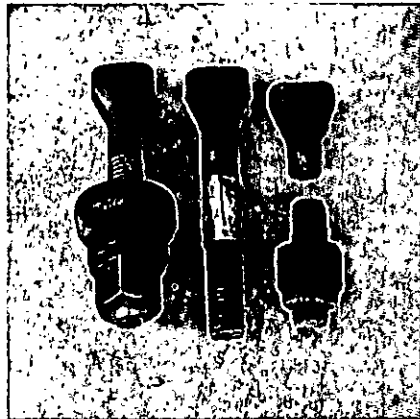
1.3.3.6 OTHER ISSUES

1.3.3.6.1 Trommel and Slurry Screen Opening Size

During initial operation, slurry production rates were often limited by the screen opening size in both the trommel screens at the rod mill discharge and the slurry screens at the entrance to the run tanks. The Moyno mill discharge pumps were replaced with centrifugal pumps that can tolerate much larger particles, so the opening of the trommel screens was increased. The trommel screens no longer limit throughput as long as slurry concentration is maintained in a reasonable range. Likewise, the Geho representative reported that Polk's main slurry feed pump could tolerate up to ½" particles without damage, so slurry screens with larger openings were installed which eliminated that throughput restriction.

1.3.3.6.2 Rod Mill Liner Backing and Bolts

The rod mills have an internal liner consisting of hard steel plates to protect the shell. The liner plates are affixed by bolts. Initially there was a foam rubber layer between the liner plates and the rod mill shell. Breakage of the bolts which secure the rod mill liners became a problem immediately after start up. See Figure 1-3. This, we believe, was mainly caused by not following the recommended torque procedure during start up. In March of 1997 we had to remove the liners and replace the foam rubber backing. This eliminated the breakage problem for a few months, but it began again in August 1997. Eventually another design flaw in the liners surfaced. The offset between the liners was not sufficient to prevent racing in which an open path between the liners allows the slurry to flow freely causing accelerated wear. This began to affect the mill shell causing ¼" grooves to form between the liners. See Figure 1-4. To control this, in May 1999, a 60 durometer ¼" rubber backing material was installed behind the liners. This protected the mill shell but did not stop the bolt breakage problem. Analysis of the bolts by a certified lab revealed the failures were due to corrosion fatigue cracking. In November 1999 all the bolts in both mills were replaced with a 4140 type material. This temporarily resolved the issue until it surfaced again in the latter half of 2000. The excessive movement could not be contained due to the large gaps (approx. 2") between the liners caused by the racing of the slurry. In April 2001, the liners were replaced with a design that prevents racing. The bolt material has been changed from 4140 carbon steel to 416 stainless steel. To date both changes appear to be successful. We will continue to monitor both the liners for wear and the bolts for looseness.



**Figure 1-3 1 1/2" Mill Liner Bolts
(Broken Bolt On Right)**



**Figure 1-4 Racing Damage
(Left of Liner Bolt Hole)**

1.3.3.6.3 Rod Mill Pedestal/Foundation

The rod mills are mounted on elevated pedestals so the mill discharge tanks and pumps can be located above grade due to the high frequency of slurry spills and frequent flushing requirements in the area. The pedestals began to separate, causing damage to the journal bearings. This also caused mill pinion alignment problems and gear damage. The pedestals were stabilized with additional concrete and tensioning bars, which should eliminate any further movement. The installation of tie rods, completed in April 2001, appears to be controlling movement.

1.3.3.6.4 Bent Agitator Shaft

A large run tank agitator shaft was bent on three occasions. Repair time is up to two months during which the run tank is unavailable. On one occasion, the agitator tripped and was then restarted without air sparging after the slurry had settled. Operating procedures were reinforced to prevent recurrence. The other two failures were due to the high torque which is developed when the liquid level is only partially covering the upper set of agitator blades. It was impractical to eliminate operation at this tank level altogether, so we removed the upper set of agitator blades after consultation with Lightnin, the agitator manufacturer. The problem has not recurred.

1.3.3.6.5 Slurry Additives (Viscosity Reduction, pH Control)

We have processed over 20 different fuels and fuel blends at Polk. Each behaves somewhat differently in slurry preparation. We cannot yet determine beforehand if or how much viscosity moderating additive or pH adjustment will be needed for a new fuel. We are still puzzled that the original Polk materials of construction performed so poorly while similar materials performed well at

other plants. There have been empirical observations at Polk that recycled fines increase erosion/corrosion rates, but this has not been systematically studied and quantified. The process water recycled to slurry preparation could contribute to the problems, especially considering its often high chloride content, but again this has not been studied. After our initial corrosion problems, we maintained higher pH in the slurry system, but again we have not systematically demonstrated that this resulted in lower metal loss rates. These issues now seem to be under control at Polk, but research to develop a better fundamental understanding of the root causes would be worthwhile for future plants.

1.3.4 GASIFICATION & HIGH TEMPERATURE HEAT RECOVERY

1.3.4.1 PROCESS DESCRIPTION

The Polk IGCC uses a Texaco oxygen-blown, entrained-flow, gasification system with full heat recovery . The general arrangement is shown in Figure 1-5.

Coal slurry from the slurry feed pump and oxygen from the air separation plant are fed to the gasifier through a series of valves which operate in a carefully determined sequence to start the gasifier and provide positive isolation for shutdown. The oxygen and slurry combine in the process feed injector which is designed to intimately mix and disperse the fuel and oxidant into the gasifier chamber. The gasifier's carbon steel shell is designed to contain the 375 psig normal operating pressure, and an internal refractory liner protects the shell from the internal operating temperature of between 2300°F and 2700°F. An elaborate skin temperature sensing system alerts operators if the refractory liner fails.

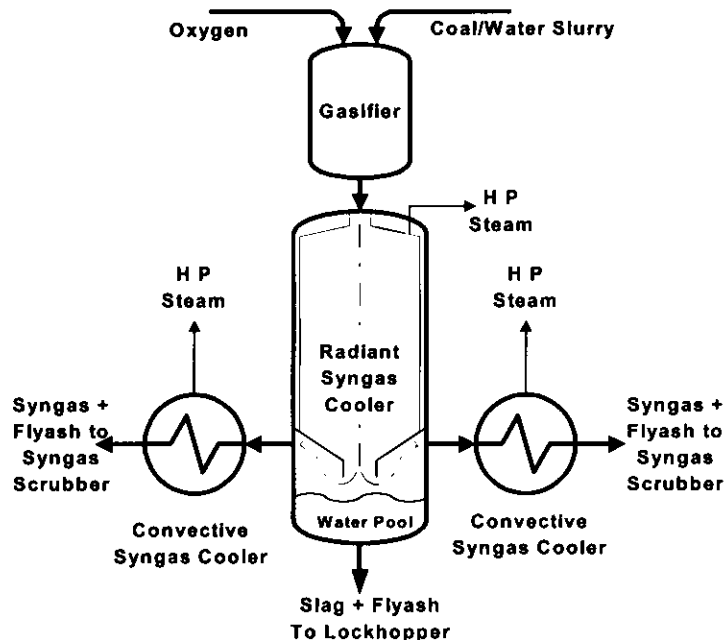


Figure 1-5 Current Gasifier/Syngas Cooler Configuration

The coal slurry and oxygen interact in the gasifier to produce three products: synthesis gas or "syngas," slag, and flyash. See Chapter 7 for their composition details.

Syngas: Syngas consists primarily of hydrogen (H₂), carbon monoxide (CO), water vapor, and carbon dioxide (CO₂), with smaller amounts of hydrogen sulfide (H₂S), carbonyl sulfide (COS), methane (CH₄), argon (Ar), and nitrogen (N₂). After moisture has been removed, the heating value of the syngas is about 250 BTU/SCF. It contains 70% to 75% of the heating value of the original fuel.

Slag: Coal and most other solid fuels contain some mineral matter which does not convert to syngas. Part of this mineral matter melts at the gasifier's elevated temperature and flows down the gasifier's refractory-lined walls. This material is called slag. It ultimately solidifies into an inert glassy frit with very little residual carbon content.

Flyash: Some of the coal particles are not completely gasified; their contained volatile matter flashes off, and the residual carbon is only partially gasified, forming char particles. This char is referred to as "flyash," although its physical characteristics are quite different from conventional coal boiler flyash. Flyash particles contains a considerable amount of residual carbon plus the mineral matter from the coal particles. Flyash is transported out of the gasifier with the syngas.

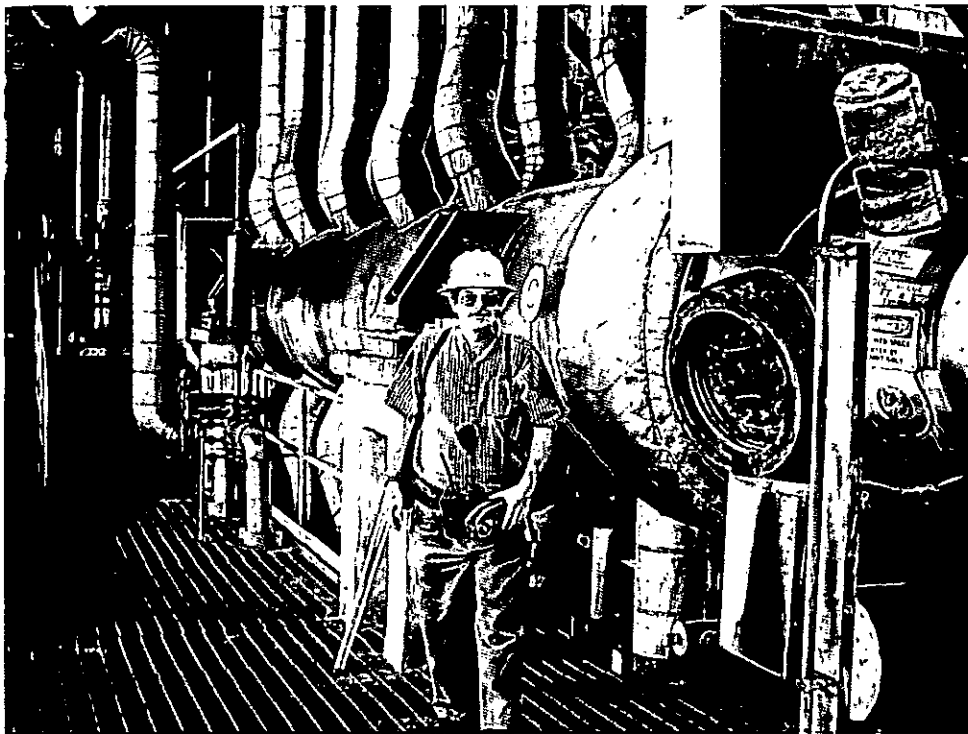
In one popular version of the Texaco process, the gasifier exit stream is immediately quenched in water which cools it to less than 500°F. However, in Polk's configuration, the high temperature gasifier exit stream flows through a radiant syngas cooler (RSC) for improved efficiency and reliability. The RSC is a high-pressure steam generator and gas cooler. The gas flows through the center of a ring of tubes connected together in a configuration called a waterwall. High pressure 1650 psig steam is generated inside the tubes using circulating boiler feedwater. At these temperatures, heat is transferred primarily by radiation. The waterwall also serves to protect the RSC's pressure containing shell from the hot gas. The RSC was originally configured with an elaborate system of 122 sootblower lances, only 4 of which have ever been needed or used. The design exit temperature was 1400°F, but despite not using the sootblower system, the exit temperature is consistently below 1350°F. The RSC typically recovers between 250 and 300 MMBTU/Hr in the form of 1650 psig steam. This represents highly efficient and relatively trouble-free recovery of between 12% and 15% of the fuel's heating value.

The syngas passes over the surface of a pool of water located at the bottom of the RSC before exiting. The water pool collects virtually all of the slag and about half of the flyash. The slag and flyash removal and separation systems are discussed in Section 1.3.5 of this report.

The syngas and flyash leave the bottom of the RSC with the flow equally split between two water-cooled transfer ducts. Two RSC exits are provided to accommodate the Hot Gas Cleanup system discussed in Section 1.3.6.6.1.

Commercial plants would only have one RSC exit duct. The transfer duct configuration is that of a double pipe heat exchanger with the gas in the inner pipe. The annulus contains medium pressure circulating boiler feedwater, so some medium pressure steam (410 psig) is generated.

A convective boiler, referred to as a convective syngas cooler (CSC), is located at the end of each transfer duct. The gas flows through the tubes of the CSC at relatively high velocity to improve the heat transfer coefficient. High pressure boiler feedwater circulates through the shell side by natural convection, generating additional 1650 psig HP steam. The gas leaves the CSCs at a temperature between 700°F and 750°F. Together, the transfer ducts and CSCs recover an additional 3% to 4.5% of the coal's heating value.



**Figure 1-6 Convective Syngas Cooler
Handhole Nozzle (Right) for Inspection and Some Cleaning of Outlet Tubesheet**

The CSCs are subject to periodic plugging; hence they are not as trouble-free as the RSC. Originally, high temperature heat recovery exchangers, called clean gas heaters, were located at the exit of the CSCs, but they had to be removed as a consequence of damage from the same sort of plugging. Now, the gas leaving the CSCs goes directly to the syngas scrubbers in the gas cleaning section discussed in Section 1.3.6.

1.3.4.2 STARTUP AND OPERATION

Prior to slurry introduction, the gasifier must be preheated to between 2200°F and 2400°F. A dedicated propane burner is used. The heat-up rate is held between 50°F and 100°F per hour to protect the refractory. At this rate, preheating takes from 30 to 36 hours from ambient temperature. Once the gasifier has reached temperature, the preheat burner is removed, the process feed injector is installed and connected, all the necessary valves are aligned, and the slurry and oxygen are introduced instantaneously at about 60% of full load through a fully automated valve sequence. If the gasifier had been shutdown for less than 6 hours, the preheating and burner change steps can be omitted because the gasifier is still hot enough to perform a "hot restart." Full operating pressure is reached in a matter of 10 to 15 minutes after first introducing slurry and oxygen, but it usually takes from one to two hours before all downstream systems are lined out so we can transfer the combustion turbine to syngas fuel. The rate-limiting step for switching the turbine to syngas is often warming the long syngas line from the gasification plant to the combustion turbine.

Normal operation is relatively simple. Adjusting the slurry (fuel) rate controls the syngas header pressure. The plant's overall station controls usually do this automatically. Adjusting the ratio of oxygen to slurry controls gasifier temperature. Knowing the gasifier temperature and choosing an appropriate target operating temperature are more difficult.

We currently use two approaches to monitoring the gasifier temperature. A third approach is under development.

Direct measurement: Thermocouples don't survive if the thermowell is inserted into the gasifier flow path. However, they will survive for days, weeks, or sometimes months if the end of the thermowell is flush with the refractory hot face or withdrawn slightly. The farther the thermocouple is withdrawn, the longer it lasts, but the lower it reads relative to the refractory hot face temperature. At least one thermocouple must be functioning during preheat to control the preheat rate and at lightoff to assure the brick temperature is high enough for the reactions to begin when slurry and oxygen are first introduced.

Inferential measurement: Methane is formed by devolatilization of the fuel as it first enters the hot gasifier. Subsequently it is both formed and destroyed by other reactions between the gasses and solids in the gasifier. The rate and extent to which methane is formed and destroyed depends on the gasifier temperature and the fuel. Thus, a methane concentration vs. gasifier temperature correlation can be developed for each fuel. The approach to equilibrium of the relevant reactions is fairly consistent among coals but is quite different for petroleum coke blends, probably due to the reduced amount of methane available in the devolatilization products from coke. Once the correlation is developed for each fuel, it can be used to monitor and control the gasifier temperature. We rely primarily on methane correlations more than 75% of the time.

Optical Pyrometer: Both the direct and inferential approaches have obvious drawbacks. Due to these limitations and the importance of accurate temperature measurement, Texaco has developed an optical pyrometer to directly measure gasifier temperature. It has been successful for some fuels at other locations. We may install and test the pyrometer at Polk. DOE has indicated some interest in participating in the endeavor because of its importance.

The other challenge is to decide upon the temperature at which to operate. Each fuel has a different optimum operating temperature which depends primarily on the reactivity of the fuel and its slag properties. If the slag flowing from the gasifier is either too viscous or too fluid, the slag removal system will plug. Also, the refractory wear rate is worse at higher operating temperatures which is a key commercial consideration. Finally, if the operating temperature is too low, the gasifier will produce an excessive amount of flyash which will plug the systems which handle and separate process water, ash, and slag, and the equipment which recycles the flyash to slurry preparation. These issues were discussed in some detail for two of Polk's specific fuels in a paper presented at the 1997 Gasification Technology Conference (See Appendix C). It is not yet possible to predict the behavior of a new fuel in the gasifier. Each fuel must be systematically tested to determine its optimum operating point. However, our experience with over twenty fuels and fuel blends has dramatically improved our ability to select the most suitable fuels and estimate optimum conditions when a new fuel is first introduced into the gasifier.

1.3.4.3 SAFETY

An elaborate gasifier shell temperature monitoring system shown on Figure 1-7 alerts operators to failures of the internal refractory liner which protects the shell from hot high pressure syngas. Maintaining the gasifier shell temperature sensing system in top working condition is very important. The RSC is also equipped with some shell temperature monitoring, since hot gas could contact the RSC shell if there were a breach of the waterwall.

Syngas is combustible, and two of its constituents, CO and H₂S, are toxic, so appropriate care must be taken. Area CO and H₂S monitors are strategically located throughout the plant. In addition, personnel always carry CO monitors in the process area, and 4-gas monitors (CO, H₂S, O₂, and LEL) are also used. Escape packs (5 minute emergency air supplies) are also available or carried whenever personnel are above grade. These can be seen on Figures 1-6 and 1-7.



Figure 1-7 Gasifier Shell Temperature Sensing System

**Also Visible: Escape Pack and Personal CO Monitor (from pant pocket)
Guard Rail Prevents Inadvertent Contact With Hot Surface
Gasifier Thermocouple Assembly Visible Behind Guard Rail**

A safety system, independent of the plant control system, monitors critical flows, levels, and temperatures. It shuts down the gasifier automatically if it senses a potentially dangerous condition. The safety system uses 2 out of 3 voting to avoid nuisance trips while still maintaining a high probability of activation if a truly serious condition occurs.

Changing from preheat to the process burner could expose workers to hot gases from the gasifier. To prevent this, air is drawn into the gasifier through the nozzle for the preheat burner and process feed injector nozzle with an aspirator during burner changes. Care must be taken to maintain the vacuum during the burner change, by assuring that no significant gas flow can be introduced via an extensive tag-out procedure. Once the process feed injector is installed, the air must be thoroughly purged from the system prior to beginning gasification. If not, the syngas could form a dangerous mixture with residual air. Likewise, following shutdown, all syngas must be thoroughly purged before the system is opened to introduce air.

1.3.4.4 RESOLVED AVAILABILITY ISSUES

1.3.4.4.1 Gas/Gas Exchanger Plugging 7 Forced Outages, 139 Days

In the original plant configuration of high temperature heat recovery, heat exchangers were located after the CSCs to recover additional heat by warming clean syngas and DGAN to the combustion turbine. The configuration is shown in Figure 1-8.

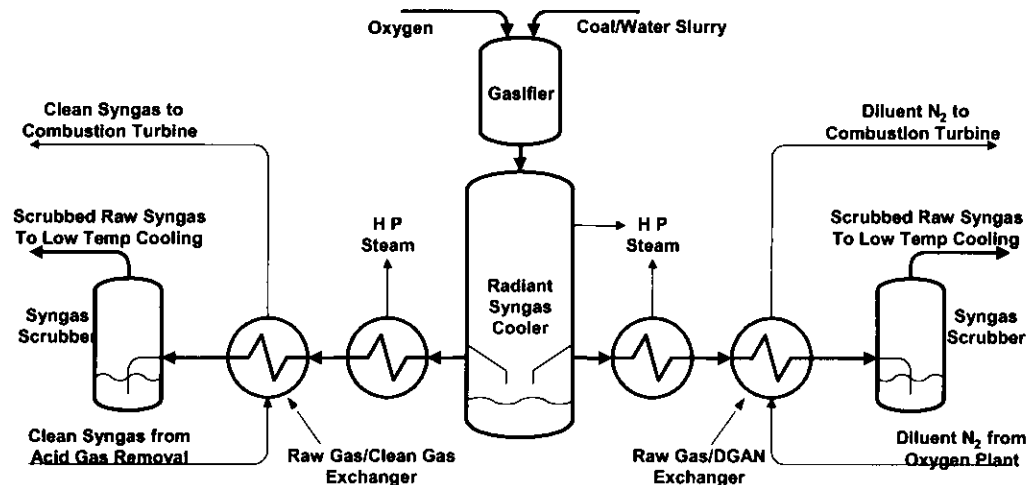


Figure 1-8 Original Gasifier / Syngas Cooler Arrangement

Flyash deposits formed in the tubes on the raw gas side of these gas/gas exchangers. Eventually these deposits led to under-deposit corrosion and stress corrosion cracking of the tubes. Tubes began failing, such that raw dusty syngas leaked into the clean gas to the turbine. On two occasions, ash deposits damaged the turbine blades. A more detailed discussion of the turbine damage and the other contributing causes can be found in Section 1.4.2 (Combustion Turbine) under the discussion of the "Y" strainers.

These exchangers recovered less than 40 MMBTU/Hr (<1.7% of the fuel's HHV), and the time and cost to repair and reconfigure them were excessive. Consequently, the exchangers were removed in mid-1997.

1.3.4.4.2 Convective Syngas Cooler Plugging
13 Forced Outages, 95 Days;
Also 15 Cleanings During Outages for Other Reasons

The same sort of deposits which destroyed the gas/gas exchangers also formed in the CSCs, particularly in the inlet. A typical deposit pattern is shown in Figure 1-9. Since problems with such deposits were anticipated in the original design of the CSCs, their metallurgy and configuration were better suited to survival. Nevertheless, CSC tube leaks did occur on three occasions when the deposits deflected the particulate-laden syngas, causing tube metal loss through erosion.



Figure 1-9 Plugged CSC Inlet Tubesheet

The deposition rate is related to fuel composition, operating conditions, and geometry. Some significant geometric improvements in 1999 led to dramatically reduced plugging rates, resulting in fewer required cleanings. We cleaned the CSCs 8 times in 1998 and 11 times in 1999. In 2000 and 2001, we only had to perform 4 cleanings per year. We also improved our ability to monitor the plugging so we could shut down for cleaning before tube damage occurred or perform the cleaning during outages for other reasons. Of the 8 total cleanings in 2000 and 2001, only 2 were done during forced outages for that purpose. In fact, most pluggage now occurs because of ash agglomerates blown into the tube entrance during high velocity operation immediately following startup. In summary, even though CSC pluggage is still a problem, it has been reduced to a manageable level.

**1.3.4.4.3 Gasifier Refractory Liner
6 Partial Replacements – Average 27 Days Outage Duration Each**

The gasifier’s refractory liner is divided into 4 independent sections to facilitate repair and partial replacement since different sections wear at different rates. The sections are the upper dome, the vertical hot face, the lower cone (floor), the upper throat between the gasifier and RSC, and the lower throat. The repairs and replacements are summarized in Table 1-1

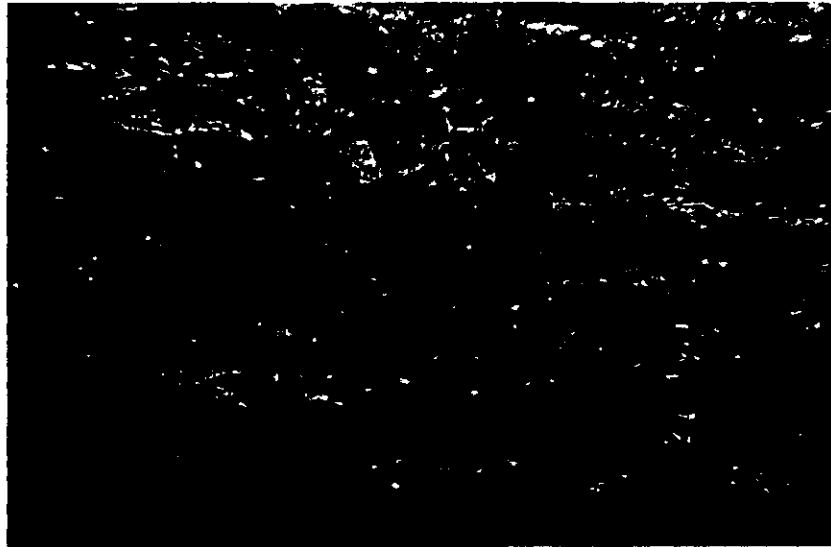
Date	Cumulative Gasifier Run Time (Days)	Dome	Vertical Hot Face	Lower Cone	Upper Throat	Lower Throat
Apr 1997	98		Replace			
Aug 1997	154				Replace	Repair
May 1998	311				Replace	Repair
Jun 1999	549	Replace	Replace			
Mar 2000	763			Replace	Replace	Replace
Mar 2001	1072		Replace			

Table 1-1 Gasifier Refractory Replacement History

The first refractory work was done in April 1997 after only 98 days of gasifier operation. The vertical hot face was replaced during an extended outage for work on the gas/gas exchangers (Section 1.3.4.4.1). This liner was of materials known to be inferior and was designated a “startup” liner. Most of the damage to this liner took place during a relatively brief period of high temperature operation in an effort to reduce the flyash production.

In August 1997, a defect in the gas seal between the gasifier and RSC was identified. It could only be corrected by removing parts of both the upper and lower throat. At that time, a design improvement was identified. The modified refractory shapes were manufactured and then installed in May 1998.

The second vertical hot face was replaced in June 1999 after it had seen 450 days of operation. We had expected this liner to last through the summer based on recent measurements. However, as the process feed injector was being removed following a gasifier shutdown for a planned power plant outage, we noticed that the back-up layer of brick was exposed in places (Figure 1-10).



**Figure 1-10 Missing Gasifier Hot Face Refractory Brick
The Back-Up Brick Liner Is Still Intact**

Apparently the hot-face brick in this area had spalled to the extent that a slight shock, in this case, probably the gasifier shutdown, caused the remaining brick to simply fall out. Spalling is a common mode of failure of this type of refractory. Molten slag penetrates and weakens the structure of the brick. Then any significant compressive load will cause a thick section to separate and fall off (Figure 1-11).



Figure 1-11 Gasifier Refractory Spalling

The planned 10 day power plant outage was extended by two weeks to complete the refractory replacement. The dome was also replaced during this outage since that had been planned for the fall outage.

The lower cone was replaced for the first time in June 2000. Both the upper and lower throat bricks were replaced at the same time.

The most recent refractory work was a vertical hot face replacement in March 2001 during an outage planned primarily for that purpose. The removed liner had experienced 510 operating days and still had some months of life remaining. However, we did not wish to risk a repeat of the previous liner's failure in the middle of the summer peak season, so we proceeded with the replacement.

As of the end of December 2001, the current liner was in service for 176 operating days. Measurements indicated it had lost about 1/3 of its useful life, but half of this loss occurred before we changed to the current fuel, a blend of 45% Black Beauty plus Mina Norte coals with 55% petroleum coke. The excellent indicated life expectancy of this fuel blend is shown in Section 5.2.4, Figure 5-8. Since we plan to remain on this fuel blend for the foreseeable future, we expect this refractory liner to last through 2002.

Polk's commercial goal for the gasifier refractory is a two calendar year liner life at high on-stream factor. We have not quite achieved this goal, largely because of our frequent fuel changes. As we learn more and are able to find a consistent long-term fuel, this goal is very attainable.

1.3.4.4.4 Radiant Syngas Cooler Seals 5 Forced Outages (55 Days Total) Plus 1 Planned Outage (56 Days)

The waterwall protects the RSC shell from hot syngas. Designers adopted different approaches to prevent hot syngas from coming in direct contact with the shell in the four key areas of the RSC:

- At the very top of the RSC where the gasifier refractory meets the waterwall,
- In the "roof" of the waterwall which contains penetrations for steam/water headers,
- In the cylindrical portion of the waterwall which contains the penetrations for the sootblower lances, and
- At the bottom where much cooler syngas must be allowed some access to the annulus between the shell and waterwall for pressure equalization.

Each of these four seal types presented some initial problems:

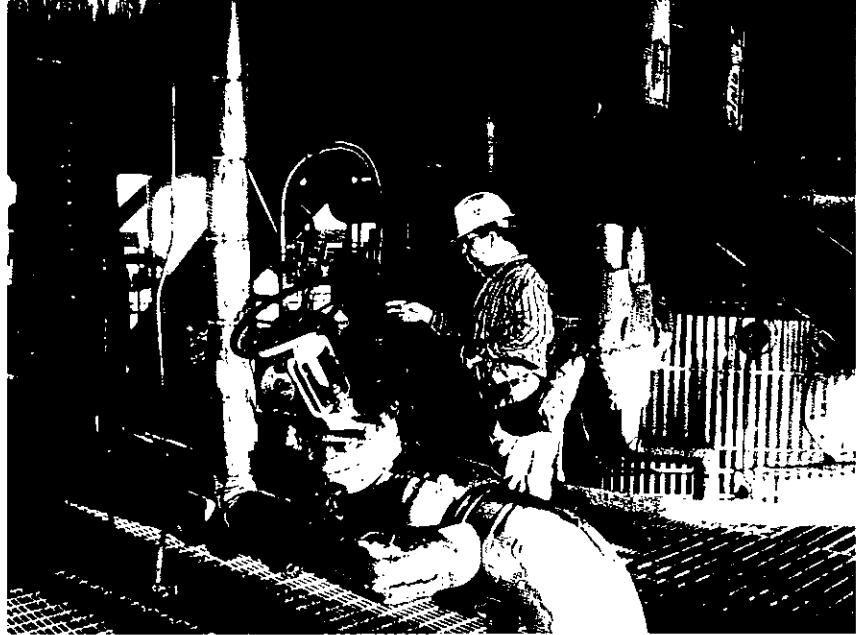
- The first seal problem occurred at the top seal where the gasifier refractory meets the RSC waterwall. This occurred in August 1997 and resulted in a 29 day outage. A fabrication defect was found and corrected. No further problems have been experienced with this seal.
- The second problem occurred in November 1997 with a seal at the horizontal "roof" of the waterwall at a steam/water header penetration. This seal design was modified in a 14 day outage, and operating procedures were developed to prevent recurrence of problems with these seals.
- Three more forced outages due to seal problems occurred in December 1998, January 1999, and January 2001, when parts of the bottom seal fell and obstructed the slag removal system. The total forced outage time from these three events was 12 days. The original design, which failed, has been replaced with an improved configuration.

We feel we are close to a final solution to the seal problems, but we will continue to closely monitor the RSC shell surface temperatures to detect any unexpected failures.

Finally, the sootblower seals caused a series of problems which ultimately led to a 55 day planned outage in mid-2001.

Extensive fouling data have been gathered at the other two Texaco solid fuel gasification plants with radiant syngas coolers on a wide variety of fuels. These plants also provided the basis for the design of the elaborate sootblower system installed at Polk which consisted of 122 lances fed by 11 large valve stations and headers. Part of this system can be seen in Figure 1-12.

After 2 years of operation on several fuels, the soot blower system has not been needed to keep RSC outlet temperatures within the design range. This may be due to the RSC's different metallurgy or slightly different geometry from the other plants, or some combination of these factors. Only four of the lances at locations known to be critical are operated regularly.



**Figure 1-12 Sootblower Valve Station and Headers
A Water Cooled Sootblower Nozzle Can Be Seen Behind the Escape Pack**

Not only were most of the lances not necessary, but they also posed three hazards:

- The flanged connections to the lances were prone to leak at both the cooling steam/water connections and syngas/nitrogen connections. This was especially pronounced on those circuits which had been operated.
- Despite a continual purge flow, soot and syngas migrated up the lances, causing deposits, condensate pockets, and severe internal corrosion of the lines.
- The seals where the lances penetrated the waterwall posed a threat of leakage resulting in hot gas impingement on the shell and shell overheating.

As individual lances or seals began leaking, we developed techniques to remove the lances and permanently seal the waterwall penetrations. By mid 2001, about 1/3 of the lances had been removed. In the gasifier runs following the refractory replacement in June 2001, a number of the seals failed, leading to a relatively rapid 100°F increase in the average shell metal temperature. The temperature trend is shown in Figure 1-13.

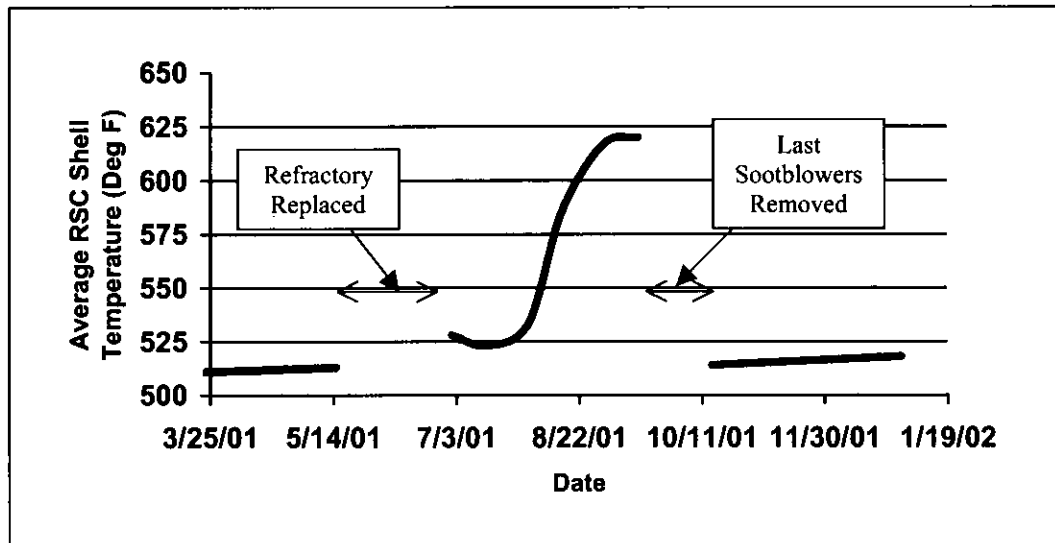


Figure 1-13 High RSC Shell Temperatures from Seal Leaks

All but 8 of the remaining sootblower lances were then removed in a 55 day outage planned primarily for issues relating to slag. The 8 remaining lances include the four in known critical locations and four others used to purge the system following shutdown and before lightoff. Elimination of most of this elaborate sootblower system should yield considerable cost saving for future plants using the Polk design.

1.3.4.4.5 Syngas Piping Leaks 7 Forced Outages; 14 Days Total

We experienced 6 small leaks in the syngas piping between the CSCs and the syngas scrubbers during early operation. The leaks all occurred at branch connections, but severe metal loss was also noted at all short radius 90° ells. These leaks cost 6 days of lost production combined. To prevent further problems, we applied erosion resistant coating to all potentially troublesome locations and eliminated as many flow path obstructions and branch connections as possible. In November 2001, a leak developed in one of the 90° ells which had been coated. The surface of the coating had cracked, and a small piece had fallen away, creating a local point of accelerated erosion. All coatings were repaired, where practical, or the fittings were replaced in an 8 day outage. The piping system contains 13-90° ells, and we plan to eliminate 11 of them in early 2002. The two which will remain are very accessible, so we can closely and regularly monitor them. Future plants can and should eliminate this problem almost entirely by locating the syngas scrubber immediately adjacent to the final heat exchanger in the high temperature heat recovery area.

1.3.4.4.6 Field Instrumentation Failures

7 Forced Outages or Startup Delays; 4 Days Total

It is very difficult to keep valve position switches calibrated within the relatively tight tolerances required by the gasifier safety shutdown system. Also, some position indication switches and valve positioners have completely failed on some occasions. We can now typically recover from such problems within the gasifier's hot restart window.

1.3.4.4.7 Valve Fails To Cycle Properly For Gasifier Startup:

3 Startup Delays; 3 Days Total

On three separate occasions, valves in the coal/water slurry system failed to cycle completely during gasifier startup attempts. The gasifier safety system prevented these startups from proceeding. In these cases, it was necessary to reinitiate preheat, since the gasifier temperature had dropped too low for startup by the time proper valve operation could be restored.

1.3.4.4.8 Syngas Cooler Medium Pressure Steam Drum Level Upsets:

5 Forced Outages; 22 Hours Total

The MP steam drum handles steam production from the transfer ducts and sootblower lance cooling. It was subject to level upsets leading to gasifier automatic trips whenever the plant's MP steam system was upset. Controller setpoints and tuning were optimized in October 1999, and no further trips have occurred. The drum was slightly undersized, and its stability has improved further with the elimination of most of the sootblowers. Since the MP steam generated in the high temperature heat recovery system contributes so little to plant performance and the SGC MP steam system adds considerably to the overall plant complexity and cost, future plants should eliminate this system.

1.3.4.4.9 Miscellaneous Valve/Weld Failures

4 Forced Outages; 50 Hours Total

Two forced outages were caused by weld failures resulting in pinhole leaks in critical piping systems around the process feed injector, and two others were caused by steam/feedwater valve failures.

1.3.4.4.10 RSC Waterwall Panel Leak – Bad Flow Indication

1 Forced Outage; 7 Days

A waterwall panel developed a leak during cool-down following a gasifier run in October 1998. Cooling water flow to the panel had been reduced due to an erroneously high flow indication. Differential thermal expansion between the subject panel and adjacent panels caused a weld failure and leak.

1.3.4.4.11 Sootblower Lance Failure 1 Forced Outage; 4 Days

External leakage was observed in some sootblowers, so the leaking lances were removed during a maintenance outage for other reasons. One of the lances removed was in one of four critical locations. That area plugged with ash during the subsequent gasifier run. The run had to be terminated, the ash was removed, and the leaking lance was repaired and returned to service.

1.3.4.4.12 Procedural Errors 9 Forced Outages or Startup Delays; 8 Days Total

Miscellaneous errors such as improper valve line-up, incorrect flange assemblies, improper weld procedures, and incorrect logic implementation in the gasifier safety system or control system have led to 9 forced outages or startup delays. Fortunately, other protective logic, inspections, or procedures precluded any equipment damage or injury from any of these incidents.

1.3.4.5 UNRESOLVED AVAILABILITY ISSUES

All issues causing unavailability of the gasification and high temperature heat recovery systems were discussed in the previous section. The problems have either been eliminated or reduced to a manageable level. As in the Air Separation Plant and the Slurry Delivery system, we are concerned about the aging instrumentation. We strive to completely eliminate procedural errors, and this should be possible now that the plant configuration has stabilized, and most major changes, improvements, and modifications have been completed. Finally, we very much hope for a single consistent feedstock to minimize operational difficulties and uncertainties associated with frequent fuel changes and to enable us to achieve our target of 2 year gasifier refractory liner life.

1.3.4.6 OTHER ISSUES

1.3.4.6.1 Poor Carbon Conversion

The major factor which has had a severe negative impact on the IGCC's overall economic and technical performance has been the gasifier's lower than anticipated carbon conversion. Based on performance of other smaller Texaco gasifiers, Polk was expected to achieve between 97.5% and 98% per pass carbon conversion under operating conditions that resulted in economically viable gasifier liner life. Instead, we have not quite achieved our 2 year liner life goal with carbon conversion levels in the low to mid 90% range. We were forced to make substantial additional capital investments in the slag and fines areas of the plant to merely handle all the unconverted carbon. We also incurred oppressive costs for slag disposal, since its high carbon content and abrasiveness render it useless for all known applications. Finally, the heat rate penalty is of the order of 250 to 500 BTU/kWh. Numerous

modifications to the process feed injector provided only marginal improvement. After five years of operation at Polk, most of the changes required to deal with the symptoms of the low carbon conversion problem are in place, but eliminating its root cause would be a major step toward truly cost effective and competitive IGCC power generation systems. The steps taken to deal with the problem are detailed in Section 1.3.5.6.1.

1.3.4.6.2 High Carbonyl Sulfide Production

The gasifier produces twice as much carbonyl sulfide (COS) as expected. Dealing with this COS has led to a significant availability penalty due to problems in the gas cleaning section of the gasification plant. The issue is discussed at length in Section 1.3.6.4.1.

1.3.5 SLAG, FLYASH, BRINE, PROCESS WATER

1.3.5.1 PROCESS DESCRIPTION

Figure 1-14 shows the major slag, flyash, and process water streams. All of the slag and about 40% of the flyash from the gasifier separate from the syngas as it makes a sharp turn at the bottom of the RSC and fall into a water pool. We refer to this water pool as the RSC Sump. Makeup to the RSC sump is particulate-free and chloride-free process condensate from the low temperature gas cooling section of the gasification plant. A steady blowdown stream from the RSC sump, containing some of the flyash, goes to a vacuum flash system. Water, which contains a significant amount of flyash, such as this, is known as black water.

The slag and the flyash which are picked up in the RSC sump descend through the water and pass through a slag crusher enroute to a lockhopper. The lockhopper discharges 3 to 4 times per hour to a drag flight conveyor. As the lockhopper dumps, it is flushed with stripped condensate. Stripped condensate is process condensate from which most of the ammonia has been removed by steam stripping in the ammonia stripper. Note that only streams free of chloride and relatively free of ammonia are used as make-up to the RSC sump and lockhopper. This is to minimize the ammonia and chloride in the wet slag product stream, since they rendered the slag unmarketable.

The drag flight conveyor deposits the slag and flyash onto a washed slag screen. The coarse material from the top of the screen, (glassy slag) containing 10%-15% combustible material when coal is the feedstock, has been sold to the cement industry. The water and the fine solids which pass through the screen (flyash containing 30% carbon or more) constitute another black water stream which is pumped to the settler feed tank.

The 60% of the flyash from the gasifier which isn't collected in the RSC sump travels with the syngas through the CSCs to the syngas scrubbers, where it is removed by intimate contact with water. Most of the chloride in the coal is converted to gaseous HCl in the gasifier, and this HCl is also removed in the scrubbers. The two black water blowdown streams from the two scrubbers enter the vacuum flash drum through separate pressure let-down valves, as does the RSC sump blowdown black water stream. The major make-up water stream to the syngas scrubbers is grey water, formerly black water from which the particulates have settled out. A small process condensate stream performs a final polishing in trays at the top of the scrubber to improve removal of particulates and chlorides from the syngas.

The syngas leaves the scrubbers saturated with water vapor, containing a $30\% \pm 3\%$ H₂O. The syngas undergoes one final wash step with process condensate in a KO drum just upstream of the COS hydrolysis unit to protect the COS hydrolysis catalyst in the event of a scrubber upset. The blowdown from this KO drum also goes to the vacuum flash drum through a dedicated pressure let-down valve.

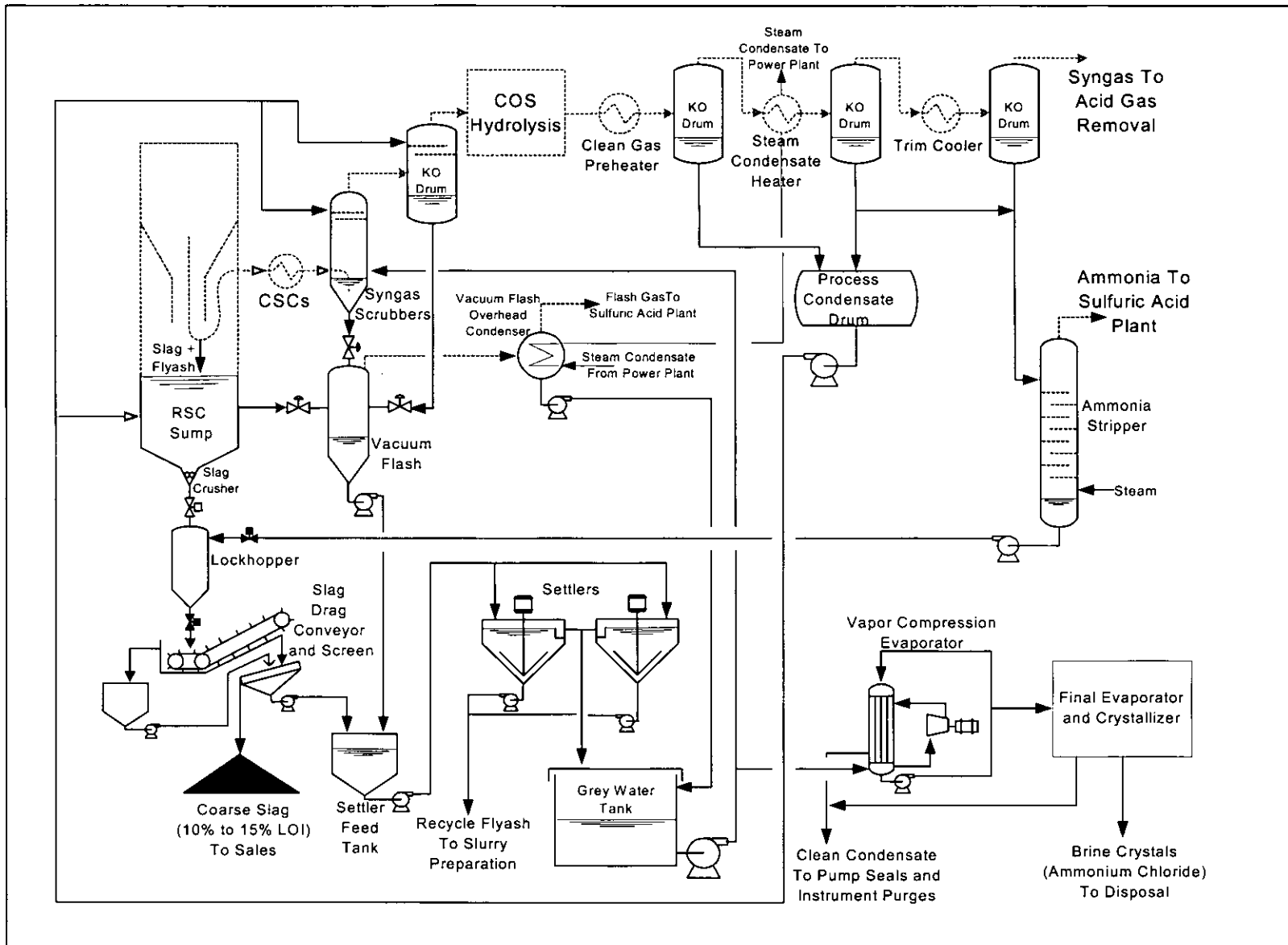


Figure 1-14 Slag, Flyash, Brine, and Process Water Flow Diagram

Four black water streams feed the vacuum flash drum: the RSC Sump blowdown, a blowdown stream from each of the two scrubbers, and the blowdown stream from the KO drum before COS hydrolysis. The pressure of these streams is reduced through heavy-duty flash valves from the system operating pressure to the vacuum flash drum. A considerable amount of water vapor is flashed off in the pressure reduction step. The flashed steam is condensed by preheating steam turbine condensate, recovering waste heat. A vacuum pump delivers the non-condensable gases, mostly CO₂, to the sulfuric acid plant.

The vacuum flash drum bottom stream is pumped to the settler feed tank, where it is mixed with the black water from the coarse slag screen. The black water from the settler feed tank is distributed to the two gravity settlers. The settlers concentrate the flyash into bottom streams which are normally sent to the slurry preparation area for recycling to the gasifier.

The settler overflow streams are relatively particulate free and are referred to as grey water. A large grey water storage tank provides surge capacity. Most of the grey water is recycled to the syngas scrubbers, but a side-stream of up to 100 gpm is sent to the brine concentration system. This serves two purposes, first to maintain a constant inventory of grey water, and second to prevent dissolved solids, particularly chlorides (Cl), from building up in the grey water to a concentration that would become corrosive. The brine concentration system consists of two main steps, first a vapor compression cycle, where most of the water is efficiently evaporated, and second a final evaporation and crystal removal step. The condensate is returned to the process for pump seals and instrument tap flushes. The brine salt, mostly ammonium chloride, is presently sent to a landfill, but potential markets are being investigated.

The final part of the process water system is process condensate. The syngas from the scrubbers contains approximately 30% water vapor. This is equivalent to 275 gpm at full load. The gas first passes through COS hydrolysis and then three coolers, where its temperature is reduced to near ambient as the water vapor is condensed. This condensed water vapor is referred to as process condensate. The process condensate from the higher temperature exchangers contains very little ammonia. It is sent to the scrubbers and KO drum for particulate removal and to the RSC sump as make-up via the process condensate drum. The process condensate from the cooler exchangers contains most of the ammonia produced in the gasifier. It is routed to the ammonia stripper, where steam stripping removes the ammonia. The ammonia gas flows to the sulfuric acid plant for conversion to harmless N₂ gas plus water vapor. The ammonia stripper bottoms is referred to as stripped condensate and is used to flush the lockhopper.

1.3.5.2 STARTUP AND OPERATION

The slag, flyash, brine, and process water subsection of the plant is unquestionably the most difficult to operate and maintain. One common problem area is slag removal from the RSC sump. If the gasifier temperature is either too hot or too cold for proper slagging operation, large agglomerates form and plug the entrance to the slag crusher. We have developed operating techniques to detect such pluggage and break up the agglomerates on-line before they have a chance to fill the entire RSC sump with slag, forcing a shutdown. Piping associated with the lockhopper system is prone to both pluggage with fines and erosive failure. The line segments most subject to erosive failure have been flanged, and spare spool pieces are kept on hand. Operators must always be prepared to quickly isolate leaking line segments and change out the spool pieces.

No throttling valves, other than those with expensive erosion-resistant design features, will survive for long in black water service. If the valves do happen to survive for a time, the control valve station will be a site of frequent pluggage and leakage. Such problems must be eliminated as much as possible in the design phase. Except the high pressure let-down valves into the vacuum flash drum and one other which is scheduled for removal in the spring 2002 outage, all black water control valves have been eliminated from Polk in lieu of variable speed drive pumps. The HP letdown valves to the vacuum flash drum are specially modified angle valves which have provided good service. Nevertheless, they are very prone to pluggage every time the gasifier starts up. The bottom of the syngas scrubber is also prone to pluggage, especially at gasifier startup. Some of the same techniques used to break up slag agglomerates at the bottom of the RSC sump have been successfully used in the scrubbers to clear this pluggage. Nevertheless, every gasifier startup is an adventure for the operators in unplugging the scrubber bottoms, the HP grey water letdown valves to the vacuum flash drum, and/or the lines connecting them.

Just about every fuel requires a different chemical addition program in the settlers to produce clean grey water in the overflow. A water chemistry consultant determines the proper formulation by using his experience and trial-and-error testing. Despite these efforts, often during fuel changes or process upsets, the settlers will not produce clear overflow water to the grey water tank. Over time, sludge builds up in the bottom of the tank from these events, and there is no good way to remove it. This sludge periodically plugs the suction line of the high pressure grey water pump which delivers make-up water to the scrubbers. Operators must be prepared to quickly divert water to the scrubbers from alternate sources when this happens until the pump can be returned to service. A further complication of dirty grey water is that the particulates build up in the vapor compression evaporator of the brine concentration system, forcing an outage to clean it. Fortunately, brief outages can be taken in the brine concentration system without having to shut down the gasifier.

1.3.5.3 SAFETY

The greatest safety concerns in this section of the plant arise due to erosion and plugging. When erosion results in a leak, even a water leak, there is the chance it could propagate and release so much water that the associated equipment could run dry and syngas, possibly at very high temperature, could begin leaking. Consequently, operators must be skilled at isolating line segments or systems quickly and safely. Likewise, operators must be very careful when trying to unplug black water lines while the gasifier is operating

1.3.5.4 RESOLVED AVAILABILITY ISSUES

1.3.5.4.1 Lockhopper Pluggage

10 Forced Outages, 25.3 Days Total

When gasifier-operating temperature is inappropriate for good slagging operation (either too hot or too cold), large agglomerates plug the inlet to the slag crusher. This happened on 9 occasions prior to June 1999, most often when we were changing fuels. Three steps have eliminated this problem. 1) Texaco provided us with appropriate tools to predict slag behavior in early 1999. This enables us to do a much better job of selecting appropriate operating temperatures for new fuels. 2) We began removing sootblower lances at that time. The lances were accumulation sites for the large agglomerates which plugged the system, and, 3) We enlarged the slag crusher inlet and installed 2 other supplemental systems to break up slag agglomerates. The only forced outage we have experienced since June 1999 due to lockhopper system pluggage lasted only 6 hours and was due to an inadequate lockhopper flush after switching slag handling systems.

1.3.5.4.2 Leaks At Syngas Scrubbers

14 Forced Outages, 21.3 Days Total

High volumes of water are circulated at the syngas scrubbers to thoroughly wash the particulates out of the syngas. The circulating water contains particulates which are very erosive. We made several modifications to the system such as installing erosion resistant overlays in the areas most subject to erosion. These modifications have been highly successful. Forced outages due to leaks in this system had been averaging 3 or 4 per year, but only one occurred in 2001. Nevertheless, this is a high maintenance system, and we must perform thorough inspections and replace components during almost every gasifier outage.

1.3.5.4.3 Slag Crusher Seal

8 Forced Outages or Startup Delays, 4.3 Days Total

The slag crusher is a motor driven device with the motor external to the RSC sump. Consequently it requires a shaft seal. The original seal system provided with the slag crusher did not survive for long in these difficult service conditions. We redesigned the seal with the help of Texaco, based on the design which was successful at a similar plant. The new design has been successful. There has been no lost time due to slag crusher seal problems since September 1999.

1.3.5.4.4 Miscellaneous Hardware/Instrumentation Failures

3 Forced Outages, 1.1 Day Total

Only 3 brief forced outages are attributable to miscellaneous hardware or instrumentation failures in this plant section. In one case, 2 out of the 3 RSC sump level transmitters failed, leading to an automatic gasifier shutdown. On another occasion, both high pressure grey water pumps, which supplied makeup water to the syngas scrubbers, were simultaneously out of service, due in large part to cavitation from plugged suction lines. The third case was due to a valve actuator failure on the lockhopper system, which prevented discharging slag. In all cases, improvements were made in the respective systems so that failures of these types should be very rare.

1.3.5.5 UNRESOLVED AVAILABILITY ISSUES

1.3.5.5.1 Black Water Line/Vessel Pluggage

4 Forced Outages:

44 Hours First Instance, 17 Hours Total Last 3 Instances

Sometimes critical black water lines or equipment have been plugged so badly that it required a gasifier shutdown. This has happened on 4 occasions. In 3 of the 4 instances, the pluggage was cleared within a hot restart window, so only a few hours of production were lost. The first instance occurred in early 1997 before the hot restart procedure was developed. Over time, we have improved our ability to clear such plugs while the gasifier stays on line by streamlining piping systems and adding appropriate isolation valves, purge connections, and drains or rod-out points. We expect that such pluggage will still occur, especially immediately after gasifier startup, and occasionally will force a brief gasifier shutdown. Startup poses the highest risk for such pluggage. Hard scale builds up on equipment walls during operation, especially the walls of the scrubbers and vacuum flash drum (See Figure 1-15). When the gasifier shuts down and then restarts, this scale layer is subjected to thermal cycles, and parts of it spall off, causing pluggage.



Figure 1-15 Hard 2 Inch Thick Scrubber Scale

1.3.5.5.2 Lockhopper System Process Line Leaks 4 Instances, 21 Hours Total

When preparing to dump the lockhopper, the first step is isolation: the main large valve closes between the RSC sump and lockhopper. The second step is depressurization through a small valve and line. For an instant, extremely high velocity choke flow occurs through the valve and downstream pipe spool as the lockhopper pressure falls from 350 psig to atmospheric. A similar condition occurs during pressurization after the lockhopper has finished dumping. Erosive failure occurs periodically in these high velocity zones. Also, a circulating black water loop with a control valve station helps draw slag and fines into the lockhopper. Leaks have occurred at this control valve station which could not be repaired on-line because the isolation valves did not hold. This is the last black water control valve station in the plant (other than the special high pressure let-down stations to the vacuum flash drum). The control valve station will be eliminated and the pumps converted to variable speed drive at the next major outage. A preventive maintenance program prevents many failures at the pressurization and depressurization stations, and about 2/3 of those that do occur on-line can be repaired without shutting down the gasifier. However, failures will occasionally occur which will require a shutdown.

1.3.5.6 OTHER ISSUES

1.3.5.6.1 Low Carbon Conversion

The gasifier's lower than expected carbon conversion, discussed previously, manifests itself in costly problems in the slag, fines, and process water separation section of the plant. Twice as much flyash and associated black water had to be accommodated in fines handling, compared to design, which overloaded that part of the system. The heating value of the increased unconverted carbon was typically about 50 MMBTU/Hr or 2% of the feed coal's HHV. This loss resulted in a heat rate penalty of 200 BTU/kWh. The extra unconverted carbon also created a considerable disposal problem. The plant typically generated 200 tons/day of wet sloppy fines from the rotary vacuum filters. To make matters worse, the high fines content of the 200 tons per day of lockhopper slag was one of the factors which made it unmarketable. Other factors that made the slag unmarketable were its high chloride and ammonia content from the grey water associated with it. Consequently, both the filter fines and lockhopper slag comprised a 400 ton/day waste stream that had to be disposed of in a Class I landfill at a cost in excess of \$30/ton. Rather than incur this disposal cost for all the slag and flyash we have produced, much of it has been stockpiled on-site, but we are now at the capacity limit of the slag disposal area that was to have provided only minimal temporary storage. The costs for plant modifications, the incremental fuel costs, and extra handling and waste disposal costs have totaled well over ten million dollars to date.

Although we haven't yet completed all the necessary modifications, we recently have shown that it will ultimately be possible to deal with the low carbon conversion problem in a cost-effective manner. The specific changes we have made date are:

- Provide the capability to recycle 100% of the settler bottoms flyash to slurry preparation
- Double the capacity of the fines handling system (settler and filter)
- Add a slag drag conveyor and screen to dewater the lockhopper slag and reduce its flyash content
- Improve reliability of high pressure grey water pumps
- Make ammonia stripper operable by improving materials and correcting a design flaw
- Eliminate contact between the slag and grey water to reduce chloride and ammonia in the slag.

With these changes, when gasifying 100% coal feedstock, we were able to produce and successfully market the slag to the cement industry while recycling 100% of the settler bottoms flyash to the gasifier and generating 235 net MW (94% of net rated output) in October 2001. However, in November 2001, we switched to a less costly fuel, a blend of 55% petroleum coke and 45% coal. Carbon conversion is even lower with petroleum coke than with coal. Consequently, the flyash content of the lockhopper slag increased beyond the capacity of the slag/flyash separation screen, so the high carbon content of the slag again made it unmarketable. At least the quantity of material for disposal was reduced, since 100% settler bottoms recycle continued to be the normal mode of operation.

Meanwhile, in late 2001, a company with experience dealing with utility boiler flyash, Charah, Inc., built a small plant on the Polk site to separate the stockpiled slag and flyash into marketable components. As of the end of 2001, the Charah plant was processing the approximately 200 tons per day of lockhopper slag while reducing the pile.

In the future, Polk has firm plans to increase the air flow to the air separation plant. This will provide enough additional oxygen so the plant can make at or very near 100% net rated capacity year around while recycling 100% of the settler bottoms flyash. We will have to evaluate whether it will be cost-effective for Polk to increase the capacity of the slag/flyash separation screens or whether we should continue to have the Charah plant process the lockhopper slag stream once the stockpile has been eliminated.

Each of the six changes we have made to date are discussed in some more detail below:

1. 100% Fines Recycle

The initial plant design did not provide adequate capability for fines recycle, since the design basis did not indicate it would be needed. Early operation showed otherwise, so appropriate piping, valves, flush connections, and flow measurements were added to facilitate operation in the recycle mode. This was completed in December 1996. The provision for recycle was necessary, in any case, to accommodate continued gasifier operation in the event of a fines filter failure or shutdown for maintenance, e.g., filter cloth changing. The first operation with 100% settler bottoms recycle occurred on January 29, 1997. The plant has periodically practiced full or partial fines recycle ever since. Fines recycle has usually not been practiced during the summer when air separation plant capacity is the lowest, since fines recycle requires more oxygen.

2. Increase Fines Handling System Capacity

Initially, fines handling consisted of a single settler and a rotary vacuum fines filter, designed to accommodate half of the flyash and water the plant actually produced. This situation severely restricted throughput and gasifier operating temperature range on most fuels. The first major modification to this part of the plant was to double the capacity of the fines handling system by adding a duplicate fines handling train, consisting of a settler and a vacuum filter. A settler feed tank was included to distribute the incoming black water between the two trains, depending on equipment condition and availability. This project built in the appropriate pumps, piping and valves to send part or all the settler bottoms flyash/water slurry to the rod mills for recycling to the gasifier. The new system was placed in service in late 1998. It enables us to handle all the fines produced from a variety of fuels over a wide range of gasifier operating conditions.

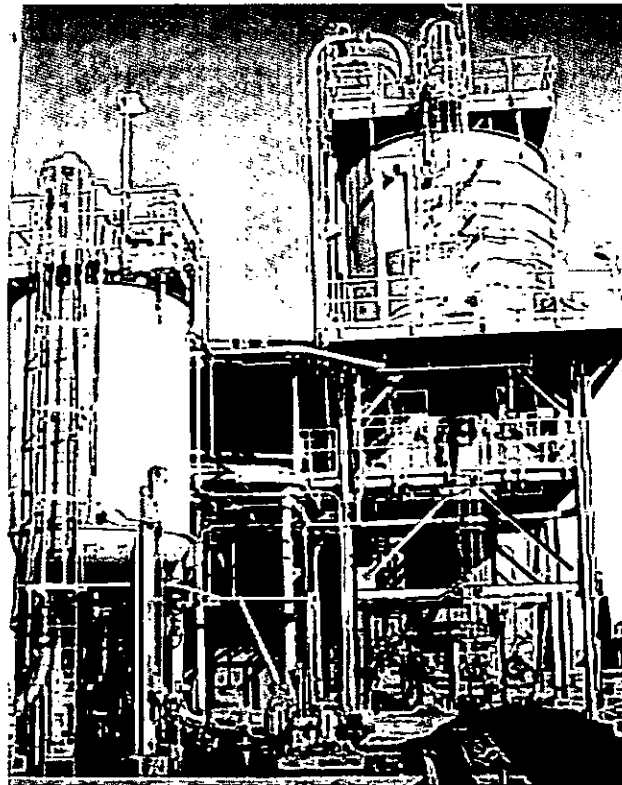


Figure 1-16 New Settler Feed Tank (Left) and Settler (Right)

3. Slag Drag Conveyor and Screen

In the initial design, slag, flyash, and water from the lockhopper flowed together directly by gravity into one of two collection/dewatering bins. One

of the bins would be collecting the slag while the other was being dewatered and then emptied with a front-end loader. This scheme was very labor intensive. The lockhopper solids typically consists of about 50% by weight slag containing little carbon and 50% by weight flyash containing up to 50% carbon. The high carbon content of the mixture plus the chloride and ammonia in the associated grey water made the slag/flyash mixture unmarketable. We needed a less labor-intensive system to separate the flyash from the slag.

Laboratory tests showed that wet screening could very effectively separate the slag from the flyash. All of the oversized material is slag with typically less than 1½% carbon. We conducted full scale screening tests with drums of actual lockhopper discharge solids to select the screen material and size. Various ways to collect and deliver the slag/flyash mixture to a screen were considered. In the end, we decided upon the approach that Texaco had traditionally used in their solid fuel gasification plants, a drag flight conveyor. We consulted other gasification plant operators and decided to purchase our drag flight conveyor from Ube industries, an affiliate of a Texaco licensee who had considerable experience with the equipment.

The equipment was placed into service at Polk in May 2000. An air-belt conveyor transports the slag from the screen to one of the old collection bins, where it is still handled by front-end loader. The new system is much less labor-intensive and much cleaner, but requires regular monitoring and maintenance. Drag flight conveyor replacement parts delivery is long, and their cost is high from the foreign supplier. Screen deck failures are frequent due to the erosive nature of the slag. The old system is used as a back-up when the air belt conveyor, drag flight conveyor, or screen fail or require a maintenance outage.

One glaring deficiency of the new system is the screen size. Despite the factory testing which was the basis for its sizing, it can only produce a marginally marketable product with coal feedstock, and it is grossly undersized for operation on petroleum coke blends with their lower carbon conversion. A key decision going forward will be whether to increase the capacity/size of the screen to accommodate petroleum coke blend fuel operation or to handle the slag/flyash mixture produced with this fuel in another manner.

Another part of this project was to optimize fines recycle. Larger flyash particles have higher heating value than the smaller particles.

Consequently, the larger flyash particles could be recycled to reduce the quantity of waste solids for disposal and to recover much of the heating value which would otherwise have been lost without requiring significant

incremental oxygen to the gasifier. Screens were installed to separate the larger flyash particles from the finer ones and drop the larger particles directly into the slurry run tanks. The concept worked, but the screens blinded rapidly, so they could only process 25% to 50% of the flyash production. Space constraints preclude enlarging the screens to the point that they would be able to serve their entire intended purpose. Also, we adopted the philosophy that we want to recycle all of the flyash, since there is no cost effective disposal means for the residual lower quality smaller flyash particles. Consequently, the concept of optimal selective recycle has been abandoned.

4. Improve Reliability Of High Pressure Grey Water Pumps

The plant water balance is such that the water separated from the fines in the settlers must be returned to the process for reuse. This is done via high pressure grey water pumps. Failures of these pumps were common during early operation. Some specific problem areas were pluggage of the suction lines with fines which had carried over from the settlers and failure of the minimum flow recirculation control (a fixed orifice) due to erosion. We addressed these problems as they arose, but because of the overall severity of the service, we concluded that the original pumps were not sufficiently robust. They were an overhung (single bearing) ANSI two stage design. One of the problems with this configuration is that the additional stage makes the pump more susceptible to vibration damage due to the extra overhang. This is an effective configuration for pumping clean water, but it is not well suited for water containing fine solids.

Replacement pumps were selected for simplicity, reliability, and cost. Centrifugal pumps remained the pump type of choice for simplicity of configuration and operation. To ensure reliability, the pumps were specified according to the more robust API standards. Ultimately, single stage overhung pumps were chosen. These pumps have operated satisfactorily, but the system has not been care free. Pump cavitation continues to be a problem, as fines carryover from the settlers still occasionally causes suction restrictions. Operating within a viable region of the pump curve is also a challenge due to the widely variable flow requirements of the process coupled with difficulty in controlling flow through the minimum flow line. Although there have been progressive improvements, this area continues to be a work in progress.

5. Make Ammonia Stripper Operable: Improve Materials Of Construction; Correct Design Flaw

The ammonia stripper was subject to severe corrosion and material failures in the top section and upsets which literally tore apart the lower trays. These failures occurred many times during early operation. After

several attempts, we finally found materials which would survive at least for a few months in the corrosive environment at the top of the column, and Texaco identified a hydraulic error in the design of the reboiler piping which probably caused the repeated damage to the lower trays. The hydraulic problem has been corrected, and the column has operated almost continually since mid-October 2001. It still has some stability problems which make it difficult to run, and these require further attention, but it is sufficiently functional to remove enough ammonia from the system, so it is no longer a major impediment to marketing the slag.

6. Eliminate Contact Between the Slag and Grey Water, Reduces Chloride and Ammonia in the Slag.

Grey and black water contain up to 3,500 ppm chloride, as well as several thousand ppm of ammonia. Both of these are unacceptable in the slag to potential users, chloride because of its corrosiveness and ammonia because of its odor. In the original plant configuration, process condensate was the primary make-up to the scrubbers, scrubber water fed the RSC sump, and the lockhopper was flushed with grey water so the slag was always in intimate contact with grey water. The plant water balance could not support bringing in enough fresh clean water to wash the chloride and ammonia out of the slag, so contact between slag and grey water had to be prevented if we were to ever market the slag. Fortunately there is enough process condensate to do this. The plant water system was completely reconfigured. Process condensate now only supplies the RSC sump, the scrubber trays, and the trays of the KO drum just before COS hydrolysis. Stripped condensate is used to flush the lockhopper. Now that the HP grey water pumps are sufficiently reliable, HP grey water is the main source of make-up to the scrubbers.

1.3.5.6.2 Brine Concentration System

The brine concentration system was designed from bench scale data. Consequently, it is the most developmental unit installed at Polk. The Process Team Members frequently are called upon to apply their cognitive skills in a team effort to make this system work and overcome the many design weaknesses in this first-of-a-kind unit. Thanks to this team effort, the brine concentration system has not been responsible for any plant unavailability. It has, however, experienced many failures and undergone many modifications, and more modifications are planned or underway to make it a truly operable unit. The key issues are:

1. Compressor Replacement and Separator Addition

The most expensive modification resulted from failure of the initial compressors for the vapor compression cycle. The brine at the bottom of the grey water evaporator, also referred to as the falling film evaporator, is very corrosive, with a pH of about 4. The steam line to the compressor suction exits the grey water evaporator vessel just above the bottom "sump". Concentrated brine is raining down from the falling film evaporator above, and thus some of this brine is entrained as a mist with the steam exiting from the bottom of the evaporator. To make matters worse, the brine in the evaporator occasionally had a tendency to foam due to contamination with MDEA solvent which increased entrainment. The initial separator was not sufficient to keep the corrosive brine mist out of the compressor, and the compressor's materials of construction were not sufficiently corrosion-resistant to survive beyond the first year of operation. After the compressor failure, the brine concentration unit continued to operate by direct steam injection. This was very inefficient, resulting in a net 2.5 MW power output penalty.

To solve the problem, an additional high efficiency separator was first added and tested to verify that it could eliminate most of the brine mist from the downstream equipment. Next, a single new compressor with an improved mechanical design and corrosion-resistant materials of construction was installed and placed into service in the spring of 2000.

The new compressor has performed well. Its robust design, coupled with improved flow capacity, enables the station to process enough grey water to accommodate fuels with a chloride content up to 0.1%, consistent with the initial plant design.

Some minor improvements are still planned in the compressor area. For example, a recirculation line and control valve station around the compressor will provide surge protection and additional superheat to overcome the amount of subcooling of the incoming grey water.

2. Crystal Recovery – Centrifuge/Belt Filter/Prill Tower

Crystal separation and recovery in the second stage of the brine concentration system has been most difficult. The initial installation included a small centrifuge. This worked well only rarely, that is, when the crystals were perfect. As an alternative, we first tested a belt filter press. Its operation was too manpower-intensive. We are currently using a homemade prill tower which performs reasonably well.

3. Pluggage/Scaling

Pluggage of the lines and scale formation on exchanger tubes are persistent problems which require almost constant operator attention. The unit has to be routinely taken out of service for cleaning by high pressure water blasting of the lines, the 1000 tubes in the falling film evaporator and the 100 tubes in the second stage concentrator.

The main source of the pluggage and scale is flyash (suspended solids) in the grey water feed whenever settler operation is less than perfect. To date, we have relied on the 550,000 gallon grey water storage tank to provide surge volume when the brine system is out of service for cleaning and to provide residence time for additional solids settling. This is less than a perfect solution, since the tank fills with solids after a few months operation. Cleaning the tank is difficult at best, and cleaning on-line is not possible. A second slightly smaller tank has recently been added which should provide more flexibility for cleaning and more surge and settling volume.

In the future, the second stage concentrator will be upgraded to larger OD tubing to reduce scaling. We will also continue to explore practical approaches to removing the suspended solids from the grey water to the brine system, improving settler operation, and tank cleaning.

4. Corrosion

Brine is very corrosive, and both internal and external corrosion are continuing issues. General external corrosion is one of the greatest current challenges. Structural steel and the external surfaces of most carbon steel pipes in the area are in poor condition. A paint product, called Xymax, provides reasonable protection, but it too eventually fails if chlorides are not totally removed from the surface before application, which is very difficult to do. Extensive reconstruction of the corroded support structures and piping has already occurred, more is in progress, and still more is planned to render this system operable for the long term.

Internal corrosion is also a continuing issue, but it has been reduced to a manageable level. The corrosive brine is very hard on the final evaporator's tubes, even though they are constructed of corrosion resistant titanium. Periodic tube replacement is a manageable expense, only because the exchanger is relatively small. In several areas, even high alloy steel pipe has not proven effective at containing the brine, so extensive use has been made of pipe internally lined with Teflon.

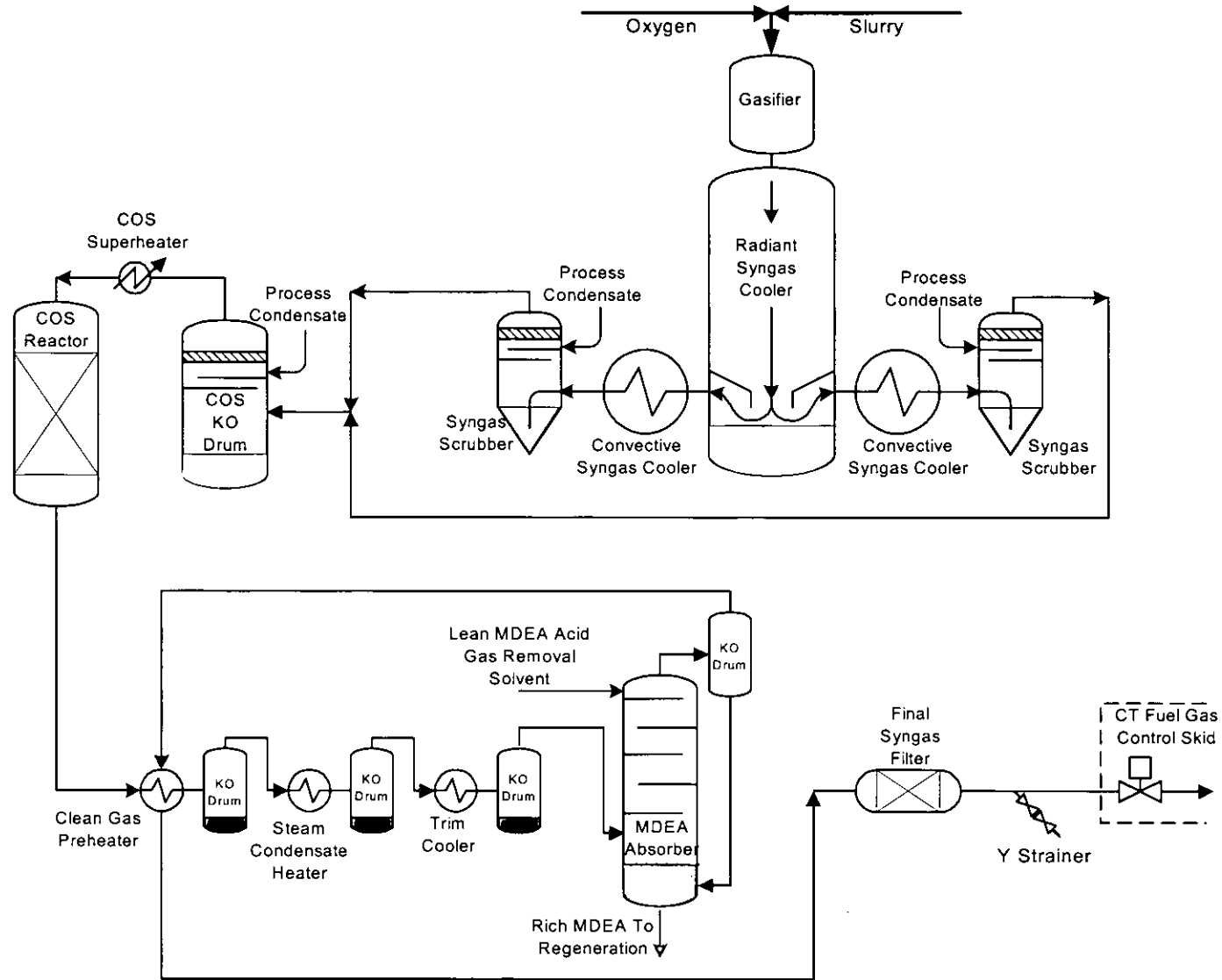


Figure 1-17 Syngas Cleaning

1.3.6 SYNGAS CLEANING

1.3.6.1 PROCESS DESCRIPTION

The Syngas Cleaning steps are all illustrated in Figure 1-17. Syngas leaves the two CSCs between 700°F and 800°F and enters the syngas scrubbers (one scrubber for each CSC). There, three water/gas contact steps in series remove most of the particulates and HCl from the gas. The water-saturated gas containing 30% ±3% water vapor leaves the scrubbers through demisters. The gas streams from the 2 scrubbers then combine and flow to a knockout drum, the COS KO Drum. This drum contains one gas/water contact step and another demister to protect the downstream carbonyl sulfide (COS) hydrolysis catalyst from contamination in case of a scrubber problem. The gas from the COS KO drum enters the COS hydrolysis area. Motor operated valves facilitate bypassing the COS hydrolysis equipment during startup and upsets.

COS hydrolysis consists simply of a superheater followed by the reactor. In the reactor, 85% to 95% of the COS in the syngas is converted to hydrogen sulfide (H₂S) by the hydrolysis reaction: $\text{COS} + \text{H}_2\text{O} \rightarrow \text{H}_2\text{S} + \text{CO}_2$. This hydrolysis step is necessary because about 5% of the coal's sulfur is converted to COS in the gasifier and is present in the syngas at a concentration of up to 500 ppmv (dry basis). Polk's acid gas removal system does not remove COS, and if all the COS were left in the syngas to the turbine, it would yield 570 lb/hr of SO₂ emissions which exceeds the 357 lb/hr permit limit. The COS hydrolysis system was added in 1999.

Following COS hydrolysis, the gas enters low temperature gas cooling (LTGC). LTGC consists of three small heat exchangers in series, each followed by a knockout drum to remove the process condensate formed as the gas cools to near ambient temperature for the H₂S removal. The first (highest temperature) exchanger in the series, the Clean Gas Preheater, heats the clean syngas to approximately 275°F enroute to the combustion turbine. The second and largest exchanger, the Steam Turbine Condensate Heater, heats steam turbine condensate (boiler feedwater) from the black water vacuum flash overhead condenser in the process water section to approximately 275°F. The third exchanger, the Trim Cooler, cools the syngas to near ambient temperature with circulating cooling pond water.

The purpose of the acid gas removal system is to remove H₂S from the syngas stream. The H₂S would otherwise be converted to SO₂ emissions, as the syngas is burned in the combustion turbine. There are several commercial systems to remove H₂S. Polk uses a 25% to 50% water solution of a liquid chemical solvent, methyl diethanol amine (MDEA). This solution removes 99.0% ±0.5% of the H₂S from the syngas, depending on specific operating conditions. Polk's MDEA configuration is standard for the industry. The syngas is introduced at the bottom of a trayed absorber and the MDEA is introduced at the top. As the gas and MDEA flow countercurrent to each other through the trays, the MDEA chemically reacts with the H₂S to remove it from the gas stream. MDEA from the bottom of the absorber flows to the top of the MDEA stripper, another trayed column, where the solvent is heated with steam from a reboiler to release the H₂S. The hot solvent from the bottom of the stripper is first cooled by preheating the

incoming MDEA from the absorber, and then with circulating cooling water. It flows to a storage tank from which it is pumped back to the absorber. The H₂S from the stripper overhead is sent to the sulfuric acid plant (SAP).

MDEA also reacts with and removes CO₂ from the syngas. This is undesirable for three reasons. First, the CO₂ helps the combustion turbine by increasing power output and improving efficiency since it represents “free” additional pressurized gas flow. Second, it reduces combustion turbine flame temperature for NO_x abatement even more effectively than diluent N₂. Third, high CO₂ removal from the syngas increases the CO₂ content of the acid gas stream to the SAP, which can result in exceeding the SAP’s gas handling capability. MDEA’s preferential removal of H₂S over CO₂ is referred to as “selectivity” for H₂S. Polk experience and testing has shown that the key interdependent variables impacting selectivity are solvent circulation rate, solvent/gas contact time (number of contact steps), MDEA concentration, and absorber temperature. Higher solvent circulation rates required for high H₂S removal rates increase the low pressure steam consumption in the stripper, which reduces overall cycle efficiency.

Trace compounds in the syngas, mostly formic acid vapor produced in the COS hydrolysis unit, also react with the MDEA. These form reaction products which, unlike H₂S, cannot be regenerated by heating in the stripper. They are called heat stable salts (HSS). If they are not removed by regeneration, they eventually “tie up” all the MDEA, making it ineffective for H₂S removal. Several approaches are available for HSS regeneration. Polk chose to install an ion exchange unit, which has proven effective.

The clean syngas from the MDEA absorber passes through a knockout drum with a demister to remove solvent mist carried over with the syngas. The gas is heated in the clean gas preheater, the highest temperature exchanger in LTGC. The gas then travels several hundred feet through a carbon steel line to the power plant area. Here it passes through a large 10 micron cartridge filter which catches most of the rust and iron sulfide particles picked up in the steel line and any other particulate contaminants the syngas contains. The gas finally passes through the “Y” strainer immediately upstream of the combustion turbine’s fuel control valves. The filter and strainer are discussed in Section 1.4.2.4.2.

1.3.6.2 STARTUP AND OPERATION

During the first 40 gasifier runs (1996 and 1997), we used the complex startup sequence provided with the initial plant design for the gas cleaning and low temperature gas cooling sections. Despite our best efforts, executing this sequence took an average of 8 hours. We streamlined the sequence to its present form, which typically takes less than 2½ hours.

Prior to gasifier lightoff, all air is displaced from the system with nitrogen to preclude forming an explosive mixture with the syngas. The entire system is depressurized. The MDEA circulation pumps are started. The power block (if running) or the auxiliary boiler provides steam to the MDEA reboiler. There are two main locations from which the startup syngas is routed to the flare, one just downstream of the syngas scrubbers (raw

gas flare valves) and the other just downstream of the clean gas preheater (clean gas flare valve). A third smaller flare valve to warm the long line (warmup valve) is located on the main syngas line at the power block. Also, the acid gas flare valve handles the startup acid gas from the MDEA stripper before it is sent to the SAP. When these valves are positioned properly, the automatic gasifier lightoff sequence is initiated.

Within 15 to 20 minutes after initiating the gasifier lightoff sequence, the plant configuration is as follows:

- The plant is near normal operating pressure at 75% of normal flow
- The raw gas flare valves have been completely closed
- MDEA circulation is established through the absorber to remove H₂S
- Acid gas is beginning to flow through the acid gas flare valve
- All clean syngas is flowing through the clean gas flare and warmup valves

Operators almost immediately begin sending acid gas to the SAP. When the syngas scrubber operation becomes stable, COS hydrolysis is placed in service which takes less than 4 minutes. Once we have verified that the gas is clean enough to be burned in the combustion turbine and that the syngas line to the combustion turbine has been warmed (this takes 90 minutes from a cold startup), the combustion turbine is transferred to syngas fuel.

Main gas path normal operation is relatively trouble-free. Pressure and differential pressure indications are monitored for signs of plugging, which occurs occasionally in the scrubbers and in the clean gas preheater. The main activity involves monitoring SO₂ emissions and adjusting circulation rate and concentration of the MDEA solvent accordingly. Filters on the MDEA solvent must be cleaned periodically. Care must be taken when returning the filters to service. If done improperly, this step can instantaneously alter the acid gas flow and composition enough to cause a flameout in the SAP's decomposition furnace. This diverts all the acid gas to the flare and necessitates an SAP restart. Foaming in the MDEA can have the same effect, so the acid gas removal plant's operation must be monitored for signs of incipient foaming.

1.3.6.3 SAFETY

The syngas contains toxic CO and H₂S, so the appropriate precautions must be taken. The MDEA acid gas contains up to 35% H₂S, so it demands particular respect. The MDEA/water solution is not combustible, but a small amount of pure MDEA, which is flammable, is kept on site for make-up. The MDEA solvent itself and the anti-foam agent injected into it are not particularly noxious, but, as with any chemical, appropriate personnel protective equipment (PPE) must be worn. The ion exchange bed for MDEA heat stable salt removal is regenerated with 25% sodium hydroxide solution for which more stringent PPE is appropriate.

Appropriate purging systems and procedures are extremely important. Provisions must be included to completely purge the system of syngas (to the flare) after all gasifier shutdowns and to purge the system of all oxygen (to the atmosphere) prior to all gasifier startups. Several modifications to the plant hardware and procedures were required to accommodate proper purging.

1.3.6.4 RESOLVED AVAILABILITY ISSUES

1.3.6.4.1 High COS Production Before COS Hydrolysis Installation

a) Scrubber Overhead Syngas Piping Failures

7 Outages, Total 29 Days in 1998

b) Low Sulfur Blend Fuel Pluggage

6 Outages, Total 18 Days in 1999

Compensating for higher than design COS production from the gasifier led to scrubber overhead piping failures and forced us to gasify some troublesome low sulfur fuel blends. These resulted in a total of 47 days of lost production in 1998 and 1999. The successful commissioning of the COS hydrolysis unit in August 1999 ended these difficulties.

Polk's Texaco gasification system converts about 5% of the coal's sulfur to carbonyl sulfide (COS). This is twice as much as plant designers expected. They also expected the acid gas removal system, MDEA, to remove half of the COS produced. Much testing, including testing with additives specifically claimed to promote COS removal, has shown that MDEA does not remove COS from the syngas while maintaining reasonable selectivity for H₂S over CO₂. Consequently, in the original plant configuration, all COS produced was converted to SO₂. This was not a problem during the first two years of operation, when we were permitted for 519 lb/hr SO₂ emissions and were processing the design coal, a Pittsburgh #8, containing only about 2½% sulfur. Its COS yield resulted in only 350 to 400 lb/hr SO₂, and MDEA could easily remove enough H₂S, to keep within permit limits. However, in late 1998, the permit limit was reduced to 357 lb/hr SO₂. Also, in an effort to reduce the cost of electricity for our ratepayers and to meet DOE requirements, we began testing various less expensive feedstocks, such as Illinois #6 and Kentucky #11 coals with sulfur content up to 3.5%. These higher sulfur coals produced proportionally more COS, so our SO₂ emissions would have exceeded our 357 lb/hr permit limit if we had not discovered a method to reduce the COS content of the syngas by about 30%. Flooding the syngas scrubber overhead lines with flyash-laden water causes about 30% of the COS to be hydrolyzed to H₂S as the syngas passes through them. This enabled us to operate on the higher sulfur, less expensive Illinois #6 and Kentucky #11 seam coals from mid-December, 1997, until mid-November, 1998, without exceeding our emissions permits. A patent (US Patent #6,322,763) was granted on this innovation. See Appendix D.

Flooding the scrubber overhead piping had one significant drawback; the scrubber overhead piping system was not designed for this turbulent three-phase operation. After only four months of operation, we experienced the first very small localized syngas leak. The first leaks were pinholes which could be easily repaired. With each repair, we reinforced and/or hard-surfaced the damaged area and intensified testing for thin spots. The damage was very localized, so conventional ultrasonic testing was not completely effective in identifying damaged areas. In response, we developed an improved testing technique. We also began planning replacement of the piping system and accelerated our plans to install a conventional COS hydrolysis unit. Finally, in November, 1998, a larger leak occurred which prompted us to take a 23 day forced outage to replace the entire piping system with upgraded materials. We also decided to no longer operate with the piping system flooded (even though the new piping system could probably accommodate it). Instead, we elected to process lower sulfur coals until we could install a standard COS hydrolysis system.

The need to temporarily gasify lower sulfur fuels prompted us to test some blends of higher sulfur Kentucky #11 (our base fuel) with lower sulfur fuels to produce a reasonable cost feedstock with an average sulfur content of about 2.2%. These blends introduced unexpected problems before a suitable blend was found. On 5 occasions, large slag agglomerates plugged the slag removal system at the bottom of the radiant syngas cooler, and on 1 occasion, slurry solids from a blend settled in the gasifier feed pump suction line, starving the pump. Altogether, problems with the low sulfur fuel blends resulted in 18 days of lost gasifier production. On a positive note, these difficulties with the low sulfur fuel blends led us to develop a better understanding of ash/slag behavior in the gasifier, enabling us to select fuels and formulate blends with much greater success.

While we were dealing with these problems, we were designing and testing catalysts for a COS hydrolysis unit in which the hydrolysis reaction takes place in a dry catalyst bed. Knowing that other gasification plants had encountered some difficulty with COS catalysts, we tested a number of catalysts side by side in a test rig consisting of three parallel reactors (Figure 1-18). Catalyst was selected, and the commercial reactor system was installed and commissioned on August 30, 1999. It has performed well, but not flawlessly, ever since.

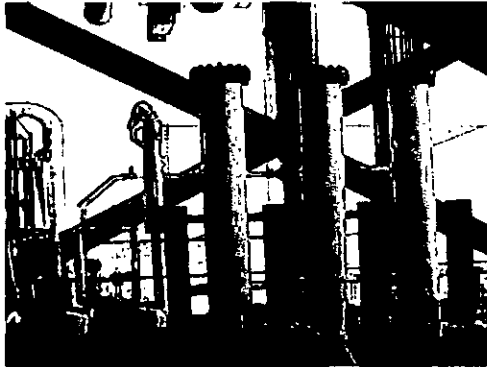


Figure 1-18 8" COS Test Reactors

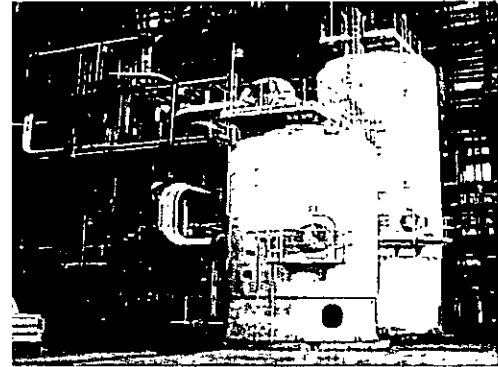


Figure 1-19 15' Commercial Reactors

The commercial COS hydrolysis unit is shown in Figure 1-19. The COS KO Drum in the foreground protects the catalyst in the reactor behind it. The structure on the left contains the small superheater and the bypass and isolation valves used for startup.

1.3.6.4.2 Formate Production In COS Hydrolysis Catalyst

1 Forced Outage, December 2000, 4.5 Days

2 Exchanger Cleanings During Maintenance Outages October 1999 and March 2001

The COS hydrolysis catalyst produces formic acid vapor which reacts with the MDEA solvent to form heat stable salts (HSS). Soon after commissioning the COS hydrolysis system, the HSS levels increased dramatically. Either sodium or potassium hydroxide is added to break the HSS bonds and regenerate the MDEA. The sodium or potassium must then be removed from the system. We used an electrolysis process, UCARSEP[®], provided by Union Carbide, our MDEA supplier. The trailer-mounted process equipment was brought to the plant as required. This was very effective, but the rate of HSS formation was so high (3½ lb-moles per day) that scheduling the service was difficult. On three occasions, we allowed the alkali metal content of the solvent to increase so high that it precipitated, creating deposits on heat exchanger surfaces. In addition, the costs of this service were quite high because of the high rate of HSS formation. We tested other COS hydrolysis catalysts and found that ours produced as little formic acid as any that were effective at our operating conditions. After evaluating the alternatives, we concluded that purchasing an ion-exchange system was the most cost effective approach. There have been no recurring problems with heat stable salts since commissioning the ion exchange system on July 10, 2001.

1.3.6.4.3 MDEA Overhead Condenser Tube Leak October 1999, 5 Days

The MDEA Stripper Overhead Condenser is cooled with circulating pond water. In October 1999, foaming in the MDEA system was uncontrollable, even with high doses of various types of anti-foaming agent. Microscopic investigation of the solvent revealed the presence of dead organisms which were not present in any archived samples. The source was identified as circulating pond water leaking into the solvent through a faulty gasket assembly in the MDEA Stripper Overhead Condenser. The gasket was replaced, and tightening procedures were improved.

1.3.6.5 UNRESOLVED AVAILABILITY ISSUES

1.3.6.5.1 COS Hydrolysis Catalyst Degeneration And Contamination

1 Forced Outage, July 2001, 4 days

5 other catalyst screenings/partial replacements during maintenance outages for other reasons: March 2001, May 2001, September 2001, December 2001, January 2002

The COS hydrolysis catalyst performed flawlessly (other than formate production) for over a year after its initial commissioning in August 1999. Since then, a series of events have led to partial deactivation and plugging of the catalyst with ash and particles of catalyst which had mechanically degenerated. This has forced us to screen and partially or completely replace the catalyst on 6 occasions beginning in May 2001. The specific circumstances which led to these problems are:

Leaking COS Superheater Tube Bundle. Steam leaks were found in the COS superheater tube bundle in late 2000. During outages, the steam leaked into the reactor and condensed on the catalyst. This led to severe mechanical degeneration of the catalyst particles, resulting in high pressure drop, channeling, and probably partial deactivation. The bundle was experiencing stress corrosion cracking, probably from mist carryover from the COS KO drum. The bundle was replaced in November 2001 with one made of more suitable materials.

Flooded COS KO Drum During Scrubber Upset. In August 2001, the COS KO drum overflowed briefly, allowing water to enter the COS reactor. This was a result of plugging in the black water blowdown line from syngas scrubbers which are immediately upstream. To prevent recurrence, the automatic controls have been modified to bypass the reactor in the event of high level in the KO drum.

Ash Carryover From Syngas Scrubbers During Scrubber Upset. During another scrubber upset, also due to black water blowdown line plugging, one scrubber's particulate removal efficiency dropped dramatically. The

remaining particulates in the gas were more than the COS KO Drum's minor cleaning capability could remove, so a significant amount of flyash entered the reactor. We can expect occasional catalyst contamination due to scrubber upsets unless we can completely solve the scrubber black water plugging problem.

Ash Carryover During Routine Operation. Earlier tests indicated that when the syngas scrubbers are operating properly in their present configuration, they remove all flyash from the syngas. However, more recent tests have revealed a significant loading of very fine particles (< 2 micron) in the blowdown water from the COS KO Drum. The fuel change to petroleum coke blends or changing the operating mode to 100% recycle of settler bottoms flyash may be the source of these finer particles which elude the scrubbers. We are experiencing gradual deterioration in performance of both the superheater and the COS catalyst, and these particles may be the cause. This issue will require continued study and evaluation.

1.3.6.6 OTHER ISSUES

1.3.6.6.1 Hot Gas Clean-Up

An initial part of the cooperative agreement between Tampa Electric and the Department of Energy was the demonstration of the Hot Gas Clean-Up Process developed by General Electric Environmental Services, Inc. (GEESI). The system was constructed and cold flow tested with the design sorbent. The testing showed that attrition was so high that operation with that particular sorbent would be far from cost effective. Additionally, the take-off point for the demonstration unit was at the exit of the convective syngas coolers, where the gas temperature was routinely $725^{\circ}\text{F} \pm 25^{\circ}\text{F}$. This was much lower than design due to the lower than design fouling factors in both the Radiant and Convective Syngas Coolers. The sorbent needed at least 900°F to achieve reasonable sulfur removal activity, and a multi-million dollar modification would have been required to provide the necessary temperature. There were other technical and commercial issues as well, so Tampa Electric and DOE mutually agreed to not proceed with the hot gas cleanup demonstration.

1.3.7 SULFURIC ACID PLANT

1.3.7.1 PROCESS DESCRIPTION

In most IGCC plants, the H_2S from acid gas removal is converted into liquid elemental sulfur in a Claus plant. Liquid sulfur is an easily transported, standard commodity chemical. However, in central Florida, there is a large market for sulfuric acid to the local fertilizer industry, so Polk elected to install a sulfuric acid plant (SAP). Figure 1-20 shows the general flow scheme of Polk's SAP. In the SAP, the H_2S is first burned to form SO_2 in the decomposition furnace which operates under a slight vacuum. This furnace also processes the flash gas stream from the black water vacuum flash drum and converts the ammonia from the ammonia stripper into harmless N_2 and water vapor. This is the best disposition for the ammonia, since the quantity is too small (less than 400 lb/hr) to be economically recovered for commercial sale. If burned directly, a significant fraction would be converted into NO_x .

A waste heat boiler at the outlet of the decomposition furnace cools the gas, typically generating 30,000 lb/hr of medium pressure steam. The gas is then further cooled and dried. This step produces a 3 to 5 gpm "weak acid" waste stream at nominally 2% to 3½% H_2SO_4 concentration by weight. This stream is currently neutralized and discharged to the cooling pond, but in the future it will be used to neutralize higher pH effluent streams. 95% purity oxygen from the ASU is then added for SO_2 to SO_3 conversion in the downstream reactors. This typically requires about 50,000 SCFH, or 2½% of the ASU's O_2 production. After being compressed to a slight positive pressure, the gas passes through three reactor beds with heat exchange (preheating, intercooling, and aftercooling) and partial bypassing as needed to maintain appropriate reactor temperatures. Gas from the 2nd and the 3rd (final) reactor beds enters the absorbing towers. Here, the SO_3 produced reacts with the excess water in the circulating strong (98%) sulfuric acid creating additional H_2SO_4 . This incrementally raises the concentration of sulfuric acid, so water is introduced as required to maintain the 98.5% H_2SO_4 target. Polk produces 200 tons per day of sulfuric acid when operating on fuels containing 3.5% sulfur (dry basis). The SAP is very efficient, converting over 99.5% of the incoming H_2S to H_2SO_4 . Over 99½% of this H_2SO_4 is produced as high purity acid which is sold. The tail gas from the final absorbing tower, containing 150 to 250 ppm SO_2 , is discharged through a dedicated stack.

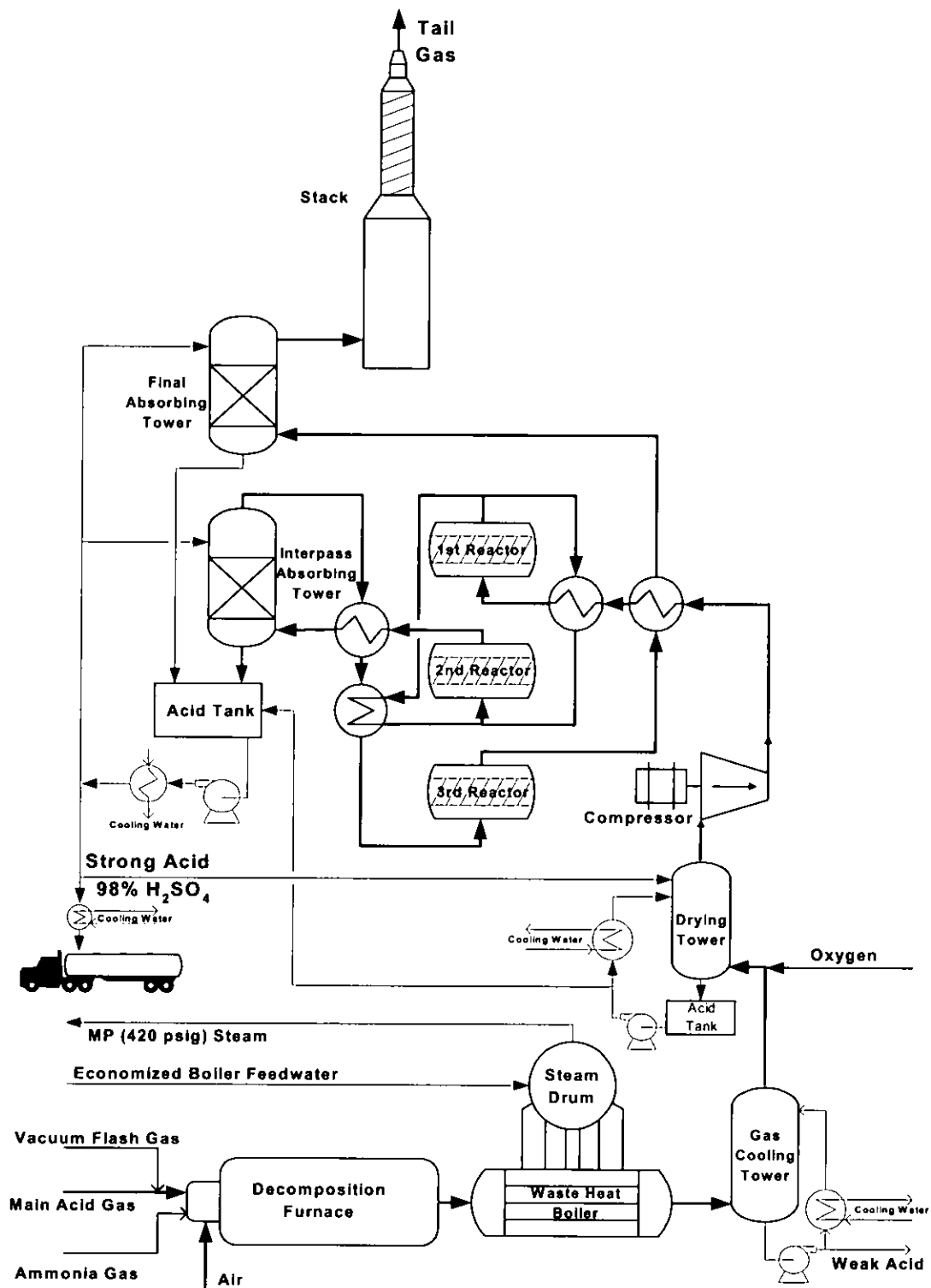


Figure 1-20 Sulfuric Acid Plant Flow Diagram

1.3.7.2 STARTUP AND OPERATION

The catalyst in the reactors must be slowly preheated to about 800°F prior to startup, which takes 48 hours if the catalyst is cold. A separate propane fired preheat furnace is used. The refractory in the decomposition furnace must also be preheated; this can be done in 24 hours by firing propane in the decomposition furnace burner.

Once the acid gas removal system operation is stable following gasifier startup, the acid gas stream is gradually introduced into the decomposition furnace over 30 to 60 minutes. If the acid gas is introduced too rapidly or too soon (before the acid gas composition is stable), several problems can result in:

- **Decomposition Furnace Flame-Out**

Combustion of the H₂S in the decomposition furnace does not produce a particularly strong or stable flame, especially with the relatively low concentration acid gas which is common immediately following gasifier startup. Minor disturbances in acid gas flow or composition can cause a flame-out, resulting in a decomposition furnace trip.

- **Catalyst Cooling**

Even though the catalyst may have been preheated properly, it is still relatively cool when the gasifier is started, compared to its normal operating temperature. Feeding too much acid gas too quickly to the catalyst can cause its temperature to drop.

- **Weak / Corrosive Acid**

Particular attention must be paid to acid concentrations during start-up periods. Gas from the Drying Tower, containing some moisture, flows to the reactor and absorption towers. During difficult startups, the reactor may not be producing enough SO₃ to react with this moisture from the drying tower. This will allow acid concentration to drop to a point where accelerated corrosion takes place in the acid plant piping, tanks, and vessels.

The first two of these problems extend the time acid gas must be sent to the flare, and the third problem will eventually lead to leaks and equipment failure. However, if the startup steps are executed properly and the equipment performs as designed, all the acid gas will have been introduced into the decomposition furnace and the SAP conversion will be above 97% within 1½ to 2 hours after gasifier lightoff.

The ammonia stripper gas has its own dedicated injection system into the decomposition furnace. It is introduced much later in the startup sequence, since the ammonia stripper is not started until several hours after gasifier lightoff. It takes some time after gasifier lightoff for the process water system to reach steady state ammonia

concentration, and establishing stable ammonia stripper operation is difficult under the best of circumstances.

Maintaining stable acid gas flow and composition are critical to preventing the decomposition furnace from automatically shutting down due to loss of flame. When the decomposition furnace trips, all of the acid gas is automatically diverted to the flare. The decomposition furnace must then be re-lit, and the acid gas reintroduced. This can typically be done faster than for the first SAP startup after a gasifier lightoff, since the catalyst beds are considerably warmer after some operation than after preheat, so the risk of losing reactor temperature is reduced.

If the H₂S concentration in the acid gas is below about 20%, it is not possible to maintain catalyst temperature without supplemental heat input. This happens if the coal's sulfur content is too low, below about 2.25%, or the MDEA selectivity for H₂S is poor. In this case, propane fired in the preheater furnace provides supplemental heat to maintain the catalyst at the required temperature. Supplemental propane firing may also be required in the decomposition furnace to maintain its temperature if the acid gas H₂S concentration is low. This is particularly important for destruction of the ammonia stripper gas in the decomposition furnace. On the other hand, when the acid gas is too rich in H₂S, above about 32%, boiler feedwater is introduced into the decomposition furnace to moderate gas temperature.

During operation, attention must be paid to acid concentrations, as all sulfuric analyzers have inflection points at which weaker acid concentrations can be erroneously interpreted as "on set-point" concentrations. If the operator is not careful, acid concentrations can drop to the point where accelerated corrosion can quickly damage piping and equipment. If concentrations begin to drop below analyzer accuracy levels, samples must be analyzed by titration methods until the acid concentration returns to appropriate levels.

1.3.7.3 SAFETY

Appropriate personnel protective equipment must be worn when working with sulfuric acid, since it is extremely dangerous.

SO₂ gas is toxic. The front end of the SAP (decomposition furnace, waste heat boiler, and drying towers) operates under a vacuum, eliminating the chance of worker exposure. However, leaks in the back end (reactors, heat exchangers, absorption towers, and interconnecting ductwork) are not uncommon, so care must be taken. The SAP area and control building are alerted to any SO₂ leaks by area monitors.

Also, acid gas does not burn at the flare tip, nor does the unburned H₂S disperse without supplemental fuel. The flare header configuration was altered, and operating procedures firmly established to provide adequate fuel whenever the acid gas is diverted to the flare. See Section 1.5.7.4.1 for additional information.

1.3.7.4 RESOLVED AVAILABILITY ISSUES

1.3.7.4.1 Decomposition Furnace Refractory Failure February 1998, 6.8 days

The refractory brick liner of the decomposition furnace failed in the area of a site glass view port, creating a "hot spot" on the shell. This view port, although relatively small on the outside, expanded in the shape of a cone into a fairly large circular discontinuity in the brick inside the furnace. This weakened the brick structure in the localized area causing the failure. This view port and all others like it were removed from the furnace. The burned, distorted steel plate section at the failed view port was replaced. The brick was restored in the localized areas, and plastic refractory was installed inside all circular sections of the view ports.

1.3.7.4.2 Non-Combustion Of Acid Gas At Flare Tip January 1998, 3 hours

Following a SAP trip, acid gas failed to combust and disperse at the flare. Operators, alerted by many of the area alarms, promptly shut down the gasifier. The flare header configuration and procedures were changed as discussed in Section 15.7.4.1.

1.3.7.5 UNRESOLVED AVAILABILITY ISSUES

There are no issues in the SAP which pose an immediate or significant threat to IGCC plant availability. The SAP does trip periodically, but it can almost always be restarted quickly. Leaks do occur, but these are usually so small that they do not interfere with operation until they can be repaired during the next outage or they can be repaired either on-line or during a very brief SAP outage. However, the SAP is an important emission control system, so if there were a major failure of any component, the IGCC plant could not operate until it was restored.

1.3.7.6 OTHER ISSUES

1.3.7.6.1 93% Acid

The local fertilizer market for 98% sulfuric acid has been weakening, since the fertilizer industry itself has taken a downturn. In response, Polk added equipment to produce high purity 93% sulfuric acid which can be used for water treatment. The main issue is not making lower strength sulfuric acid but, rather, removing traces of nitric acid which are formed in the decomposition furnace. Strides are being made to reduce the levels of nitric acid. Segregating the acid drips from the absorption towers currently indicates promising results. These new facilities are being commissioned, but as of this writing, the sulfuric acid market for the fertilizer is experiencing a slight rebound.

1.3.7.6.2 Decomposition Furnace Trips from MDEA Filter Changes

During initial operation, changing the MDEA filters led to sufficiently large fluctuations in acid gas flow and/or composition that the SAP tripped about 50% of the time. This usually occurred as the filters were being returned to service. Procedures have been improved dramatically, and valves have been added to permit returning the filters to service very slowly.

1.3.7.6.3 Decomposition Furnace Trips from Flame Scanner Problems

Burner safety systems require confirmation of the presence of a flame for operation. This must be done with a flame scanner. These devices are notoriously unreliable due to their high sensitivity to small changes in fuel composition, fuel/air ratio, and alignment. The decomposition furnace was originally equipped with two infrared (IR) flame detectors which, when carefully aligned, could satisfactorily sense the main acid gas flame. However, they had considerable difficulty detecting the propane main flame during startup, and it was almost impossible for them to sense the propane pilot flame. The two IR detectors were replaced with combination IR and ultraviolet (UV) detectors and two additional combination detectors were added. Two of the detectors are tuned to the UV frequency of the propane pilot and main flame during startup. Once the acid gas flow has been firmly established, the controls automatically switch to the other two detectors tuned to the IR frequency of the acid gas flame. These modifications have significantly reduced nuisance trips and startup problems. However, alignment of all four flame scanners remains a problem. Whenever any maintenance is performed on the burner, several hours and sometimes days of effort are required to align the scanners before reliable startup and operation of the decomposition furnace is realized.

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1.4 POWER BLOCK

1.4.1 GENERAL

The power plant is a General Electric STAG 107FA combined cycle adapted for syngas fuel operation. GE provided the engineering, manufacture, and supply of the following equipment:

- One Frame 7FA Single Shaft Combustion Turbine with 7221 Multi Nozzle Quiet Combustors (MNQC) capable of firing fuel oil No. 2 as well as syngas
- One 229,741 KVA hydrogen cooled generator (combustion turbine)
- One tandem compound, double flow condensing steam turbine with one uncontrolled extraction
- One 156,471 KVA hydrogen cooled generator (steam turbine)
- All the engineered skids required to provide the auxiliary and accessory systems for the combustion turbine, steam turbine and the generators
- Control Cabinets, including GE Mark V controls for both turbines
- One three-pressure, unfired Heat Recovery Steam Generator (HRSG) with integral deaerator. The HRSG is capable of accepting saturated steam from the gasification plant at two pressure levels and supplying steam at rated conditions of 1500 psig and 1000°F, reheat steam at 325 psig and 1000°F, and 50 psig low pressure steam. The HRSG was fabricated by Vogt under contract to GE.

1.4.2 COMBUSTION TURBINE

1.4.2.1 PROCESS DESCRIPTION

The CT ingests 3 million pounds of ambient air per hour (40,000 KSCFH) through filters into the compressor. The compressor is a multi-stage, axial machine which requires approximately 200,000 shaft horsepower (150 MW), making the CT compressor by far the largest "auxiliary" power consumer in the facility. Most of the air is distributed through internal passages within the machine to the 14 combustion cans, where it participates directly in combustion of the fuel. However, a significant fraction is diverted to cool the combustion hardware and the expansion turbine's high temperature metal parts after which it joins the combustion products as they pass through the turbine.

Clean superheated syngas from the gasification plant passes through a motor operated isolation valve and a "Y" strainer into a fuel gas skid which contains additional isolation valves and all the control and purge valves for this fuel. High pressure nitrogen

(HPGAN) from the air separation plant is used for purging. A ring header delivers the syngas from the fuel skid to each of the CT's 14 combustion cans. Equal flow distribution to the cans is achieved with fixed orifices.

Diluent nitrogen (DGAN) from the air separation plant is used for NO_x abatement and power augmentation when firing syngas. Like the syngas, it passes through a motor operated isolation valve and a "Y" strainer into its own skid containing another isolation valve and all control valves. Then, it is distributed to the individual combustion cans via its own ring header.

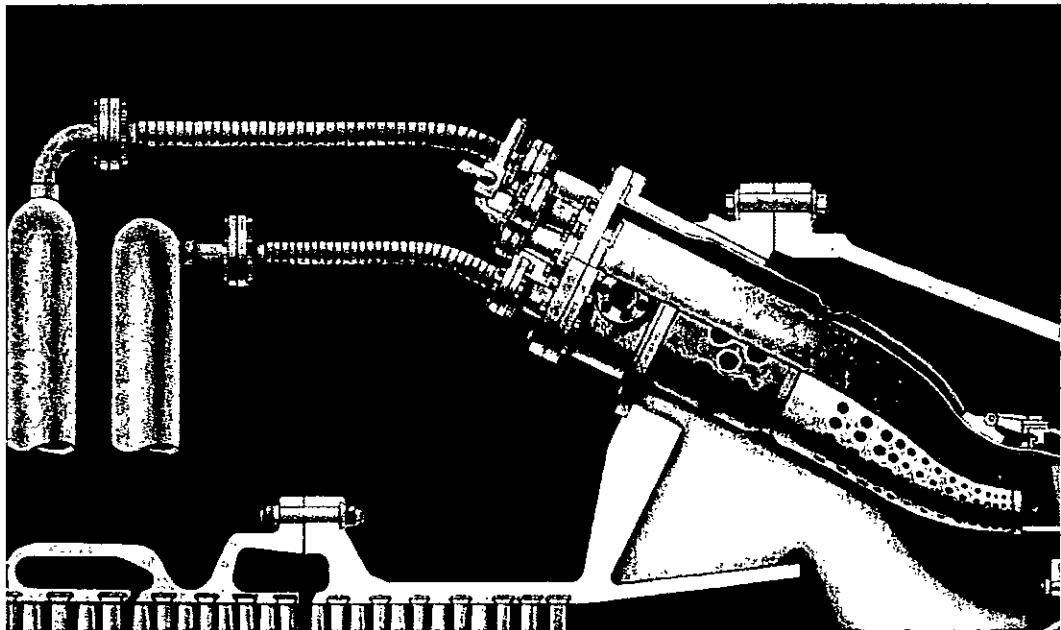


Figure 1-21 GE Multi-Nozzle Quiet Combustor

The CT's startup and backup fuel is low sulfur #2 distillate oil. Fuel forwarding pumps, located near the 2.3 million gallon storage tank, deliver filtered fuel oil to the three 50% main fuel oil pumps near the CT. These pumps discharge to a special rotating flow divider which assures equal distribution of the fuel oil to its nozzles on the combustion cans. A high speed centrifugal blower boosts the pressure of some of the CT compressor's discharge air to be used for atomizing the distillate oil. When firing distillate fuel, NO_x emissions are controlled by demineralized water which is distributed to the combustion cans.

The combustion products mixed with the air used to cool the combustion hardware passes through the expansion turbine's first stage nozzles at sonic conditions. The combustion turbine is a model 7FA, but GE's standard 7FA first stage nozzles are too small to accommodate the higher volume of combustion products from syngas. Therefore, GE utilized first stage nozzles from their earlier model 7F turbine which had a larger cross sectional area.

The hot gas flowing through the expansion turbine produces approximately 475,000 shaft horsepower. Of this, 200,000 HP is consumed by the compressor; 257,000 HP is used by the hydrogen-cooled generator to produce 192 MW; and the rest is consumed by generator and bearing losses. The exhaust gas leaves the final turbine stage at 1066°F through an exhaust plenum into the heat recovery steam generator (HRSG).

1.4.2.2 STARTUP AND OPERATION

Startup, synchronization, fuel transfer, and load change are fully automated activities that are normally initiated through signals from the distributed control system (DCS) in the main control room to the turbine's Mark V controls located in the GE Packaged Electrical and Electronic Control Center (PEECC). Startups and transfers require a complex sequence of valve actions with permissive requirements that must be met at each step in the sequence. In this sense, they are much like gasifier startups. However, in the event of a gasifier startup failure, most of the troubleshooting and diagnostic information is readily available on the DCS and in the plant's historical data collection system. In the case of CT startup and transfer failures, the key information is only available (if at all) in the Mark V to those specially trained to use it. Consequently, whenever possible, each startup and transfer attempt is visually monitored at the PEECC interface terminal or "<I>" by one of these specialists.

1.4.2.3 SAFETY

Distillate fuel leaks are commonplace, especially after inspections, and distillate fuel occasionally flashes when it contacts hot turbine surfaces. It is essential to maintain the CO₂ fire extinguishing system in good working order.

Deposits on turbine blades from syngas combustion may contain significant concentrations of harmful elements. Nickel and chromium deposits had been found before the installation of the final syngas filter, and deposits containing significant concentrations of arsenic continue to be present on blades and on HRSG surfaces. Appropriate personnel protective equipment (PPE) must be used and hygiene practiced.

1.4.2.4 RESOLVED AVAILABILITY ISSUES

1.4.2.4.1 Combustion Hardware And Hot Gas Path Inspections

The combustion turbine is covered by a long term service agreement (LTSA) between GE and Tampa Electric. Under this agreement, GE performs 10 day combustion hardware inspections (CI) every 8,000 operating hours and 14 day hot gas path (HGP) inspections every 24,000 hours. Whenever possible, these are coordinated with gasification plant outages. Through 2001, we have 34,800 hours of CT operation with 28,500 hours of syngas firing. The first HGP was performed in February 2000. The subsequent CI took place in March 2001. There have been no major surprises with the parts life of either the combustors or the hot gas path buckets and nozzles. We agree with GE

that the syngas fuel is similar to natural gas as far as the longevity of the combustion turbine parts is concerned. The normal cracking that occurs on the combustor liners has improved since the first two CIs. The improvement in liner life is attributed to the syngas final filter that was added at the second CI (Figure 1-22).

1.4.2.4.2 Syngas "Y" Strainer

- 1 Outage Extension of 6.9 days duration occurred in Feb 1997 for strainer removal following discovery of cracks in bodies.
- Absence of strainers during next 6 months made 2 major CT failures possible
- After strainer reinstallation, strainer pluggage typically caused 2 or 3 fuel transfers of 2 hours duration each for cleaning following most gasifier startups until the final syngas filter was installed.

The "Y" strainers caused the only station availability loss due to failure of the CT's syngas fuel hardware, but the consequences were dire. On February 13, 1997, during a routine inspection, cracks were observed in the bodies of the "Y" strainers on both diluent nitrogen and syngas lines to their respective CT control valve skids. These "Y" strainers were to catch large objects, such as nuts and bolts left over from construction, which could cause foreign object damage (FOD) to the turbine. Nothing had ever been found in the strainers, and the system had operated long enough that we believed any significant material would have already been removed. Also, repair time for the strainer bodies was quoted as 6 months. For these reasons, we elected to continue operation without the strainers while they were being repaired. Had the strainers been in place, they would have prevented or at least minimized the major turbine damage which occurred on 2 occasions. The first was due to flyash in the syngas fuel from the first gas/gas exchanger tube failure. The second was from a combination of pipe scale in the syngas line which had formed during an outage plus flyash from the third gas/gas exchanger tube failure. The "Y" strainer repair was finally completed and they were returned to service immediately after the third gas/gas exchanger tube failure in June 1997.

After the strainers were returned to service, they plugged with pipe scale several times after most gasifier startups. Each time, this required a transfer of the CT to distillate fuel for two to three hours so the plugged strainer could be cleaned. The syngas strainer was the one which plugged most often, so a 10 micron cartridge filter was installed in May 1998 (Figure 1-22). It was sized to catch all the pipe scale generated in 1 year. Now the syngas strainer only requires cleaning 3 or 4 times per year, mostly due to pipe scale from the 100 foot line between the strainer and syngas filter. These cleanings are usually done during outages.

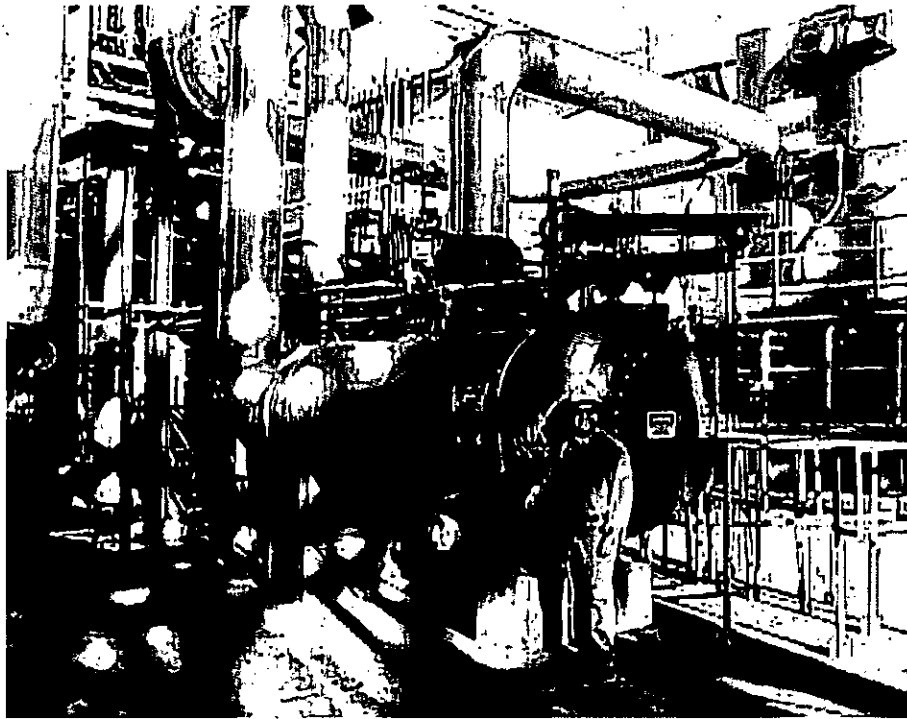


Figure 1-22 Final Syngas Filter

**1.4.2.4.3 Distillate Fuel Atomizing Air Compressor
1 Forced Outage, 7.9 Days, April 2000**

Two atomizing air compressors were installed initially to improve reliability. One was to be a standby, and the other was to run continually, even during syngas fuel operation, to provide cooling to the distillate fuel nozzles. The standby compressor was installed in a low point in the piping. It was rarely operable due to corrosion attack from accumulated condensed water. With GE's help, we made a change to the control system so the two compressors would alternate operation. However, this change was implemented in such a way that caused both compressors to surge, damaging both machines. To prevent recurrence, we returned the controls to their original configuration. We also reconfigured the piping with blind flanges to isolate the spare compressor which prevents water intrusion. Now, a failure of the operating compressor will only cause a brief outage while we pull the blinds and start the spare.

1.4.2.5 UNRESOLVED AVAILABILITY ISSUES

1.4.2.5.1 Distillate Fuel Leaks/Fires

2 Forced Outages, 5.5 Days Total, April 1999 and August 2000

Distillate fuel leaks are common, especially after inspection outages, due to the many fittings in the high pressure distillate piping/tubing system to the combustors. It is standard practice to start the turbine for a few minutes after each inspection to identify leaks, then shut it down to repair them before the turbine is declared available for service. However, on two occasions during distillate operation prior to switching to syngas fuel, small leaks were undetected. The leaking distillate fuel ignited upon contact with hot surfaces. The first in April 1999 was a leak at the fuel pump itself. The second, in August 2000, occurred as a result of a bad O-ring joint on can 14 at the apex of the unit. In both cases, the fire suppression system worked well. No one was injured and damage was kept to a minimum.

Because of the difficult environment and the many fittings, we can expect to continue to experience distillate fuel leaks and occasional fires, despite efforts to prevent them.

1.4.2.5.2 Startup And Fuel Transfer Failures

5 Startup Failures, 3.0 Days Total

In addition to the 3 days the gasifier has been kept off-line while we awaited CT startup, we have spent about an equal amount of very expensive gasifier operation time flaring syngas while waiting for the CT to start. We also suffered a number of CT trips during attempts to transfer from syngas to distillate fuel. These are very hard on the CT equipment. There are two primary causes for these CT startup and transfer problems:

- **Plugged Fuel Oil Distributor Valves**

Special distributor valves allocate fuel oil evenly among individual fuel nozzles. Varnish builds up in the distributor valves during fuel oil operation and quickly turns to carbon during long gasifier runs. The 1" liquid fuel lines to the distributor valves would also coke up with carbonized varnish as the fuel in them evaporated during long gasifier runs. This carbon residue would plug small orifices in the distributor valves which are necessary for their proper operation when transferring to liquid fuel or starting up on it. One of the orifices is shown in Figure 1-23. Two modifications have alleviated these problems:

- 1" check valves were added on the 1" liquid fuel lines to the distributor valves. This prevented purge air (see next point) from flowing into the fuel lines and drying the fuel during syngas operation.

- The liquid fuel lines were insulated and traced with closed loop cooling water to keep them cool during syngas operation.

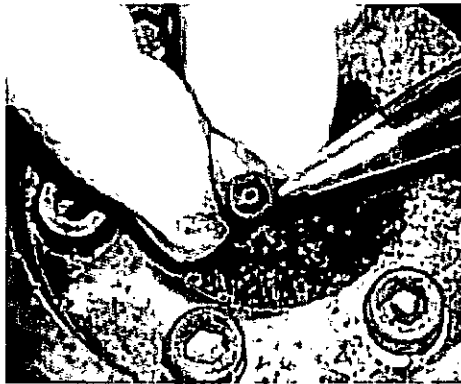


Figure 1-23 Plugged Distillate Fuel Orifice

- **Leaking Fuel Purge Check Valves**

Fuel transfers were impeded by leaking ½" check valves on the purge air lines to the distributor valves. Purge air flows through the fuel oil distributor valves during syngas operation to keep the distillate fuel nozzles cool. The source of the purge air is the atomizing air compressor which takes its suction from the CT compressor discharge main air stream. The faulty ½" check valves allowed distillate fuel to enter the purge air lines as the purge air was being shut off during fuel transfers. The fuel oil pressure in the purge air lines activated pressure switches which halted the transfer. This safety feature prevents the fuel oil from entering the air system which could lead to a fire inside the line or temperature excursions in the turbine combustion system when the purge air flow resumes. Providing an additional flow path through which the liquid fuel could drain from the purge air system alleviated this problem.

The improvements to date have not totally solved the problems but have made them bearable. Other plants with distillate as their back-up fuel have experienced similar problems. To facilitate solving them, GE recommends co-firing distillate fuel with the base fuel for a few hours each week to prevent hard sticky deposits from forming. We are working through the control issues and permitting issues to enable Polk to do this, but until then, we will be faced with these periodic startup and fuel transfer failures.

1.4.2.6 OTHER ISSUES

1.4.2.6.1 NO_x Abatement

NO_x emissions from coal based IGCC plants are as low as, or lower than, those from the best conventional coal fired power plants. Nevertheless, many people inevitably compare NO_x emissions from syngas fired CTs to those of natural gas fired CTs without completely understanding the important composition differences between the two fuels. Dry low-NO_x combustors can achieve less than 10 ppmvd NO_x (@15% O₂) emissions with natural gas fuel. High flame temperature is the source of NO_x. Dry low NO_x combustors rely on a premix principle, wherein the fuel gas is diluted with some of the combustion air to reduce the ultimate flame temperature before the mix actually enters the combustion chamber. H₂ has a very high flame speed, and the high H₂ content of syngas makes such a dry low-NO_x combustion system impossible, since the flame would draw back into the premix zone. GE's syngas combustors are referred to as Multi Nozzle Quiet Combustors (MNQC). They rely on an O₂-free diluent (N₂ or steam) to reduce the flame temperature. However, if too much diluent is used, flame instability and flame-out occur. The practical NO_x reduction limit for syngas combustors is probably somewhere between 10 and 20 ppm. On the other hand, the popular selective catalytic reduction (SCR) post-combustion NO_x control method which has been effective for sulfur-free natural gas, will not work with syngas. Unlike natural gas, syngas does contain some residual sulfur, and SCR has been proven to convert sulfur in the fuel to sulfur compounds which deposit on the HRSG tube surfaces. Polk already experiences some sulfur deposits on the HRSG surfaces. Additional deposits that would be generated by an SCR system would make Polk inoperable on syngas fuel in its current configuration.

In the initial permitting process for Polk, the achievable NO_x emission level with syngas fuel and this new combustion system was not known. Consequently, Polk was initially permitted for 75 ppm NO_x emissions for the first 2 years. The limit was then reduced to 25 ppm for the remainder of the 5 year demonstration period. After that, a "Best Available Control Technology" or "BACT" analysis was performed to determine the ultimate permit limits. This was completed in January 2001, and the permit limits will be 15 ppmvd @ 15% O₂, effective July 2003. Polk will have to provide additional diluent to meet this limit with all syngas fuels we have produced to date. We are currently evaluating whether to do this with additional air to the Air Separation Plant which would provide more DGAN, or with a syngas saturator which would dilute the syngas fuel with water vapor, or some combination of the two.

1.4.3 HEAT RECOVERY STEAM GENERATOR

1.4.3.1 PROCESS DESCRIPTION

The heat recovery steam generator (HRSG) recovers heat in the combustion turbine exhaust to produce and superheat steam and preheat boiler feedwater for the generation of additional power in the steam turbine. The HRSG is of three-pressure level, reheat, natural circulation design. Its configuration, along with that of the steam turbine, is shown in Figure 1-24.

The 1066°F combustion turbine exhaust gas enters the superheater and reheater sections of the HRSG which heat the high pressure (HP) and intermediate pressure (IP) steam to 1,000°F. This section is larger than that of a standard HRSG, since it must superheat and reheat the additional steam produced in the gasification plant.

Next is the HP evaporator which generates 165,000 lb/hr of 1415 psig steam. This is 25% to 30% of the HP steam produced in the plant. The remainder is produced in the gasification plant's syngas coolers. The SGC HP steam flows into the HRSG HP drum, so its demisters can remove the condensate it contains. Condensate is formed in the long line from the gasification plant and in the pressure let down step from the SGC 1650 psig operating pressure. A small IP steam superheater is next, followed by the hottest HP economizer which finishes preheating boiler feedwater for the HRSG HP evaporator and the syngas coolers.

The IP evaporator generates about 50,000 lb/hr of 370 psig steam which is slightly more than the amount imported from the gasification plant. The gasification plant's IP steam, which is generated at 420 psig, flows to the HRSG IP drum for demisting before it goes to the HRSG superheaters and turbine. The IP evaporator is followed by three economizer sections which preheat HP and IP boiler feedwater. Like the superheater and reheater banks, these economizer banks are larger than would be found in an HRSG for a normal combined cycle, since they must preheat the additional boiler feedwater required by the gasification plant.

Next, low pressure (LP) steam is generated in the LP evaporator for the air separation plant and the gasification plant. Finally, boiler feed water (BFW) is preheated in the last HRSG section for additional heat recovery. The exhaust gas to the stack is typically between 310°F and 340°F.

1.4.3.2 STARTUP AND OPERATION

Startup and operation of the HRSG are generally unremarkable. Special controls are used to introduce the HP SGC steam into the HRSG HP Drum following gasifier startup.

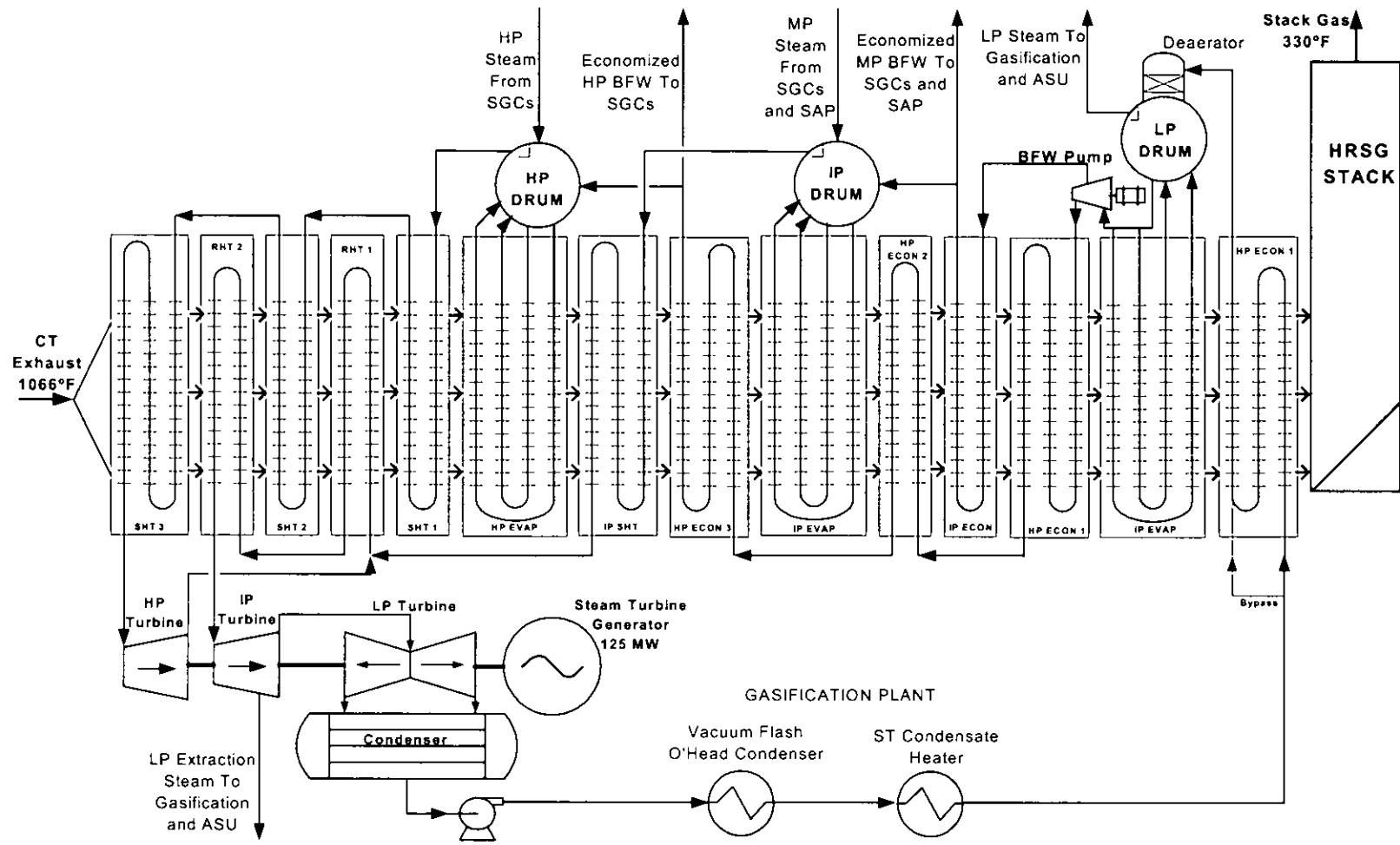


Figure 1-24 HRSG, ST, and Circulating BFW Configuration

1.4.3.3 SAFETY

Appropriate personnel protection (PPE) should be worn and hygiene practiced when entering the HRSG, due to the acidic deposits which also contain measurable concentrations of arsenic.

1.4.3.4 AVAILABILITY ISSUES

The HRSG has not been a direct source of any lost production.

1.4.3.5 OTHER ISSUES

1.4.3.5.1 HRSG And Stack Sulfur Deposits

Even though the HRSG gas-side operating temperature was maintained above the theoretical acid dew point, the earliest inspections revealed deposits of sulfur compounds on the interior of the HRSG stack and on the external surfaces of the finned tubes in various sections of the HRSG, particularly the economizer. Economizer deposits are shown in Figure 1-25. Sulfur was observed dripping down the inside of the uninsulated carbon steel stack, and when the HRSG was started, flakes of rust with concentrated sulfur deposits would be blown out of the stack and rain down on plant equipment. Analysis of the deposit samples indicated they are mostly iron sulfates, but they do contain measurable concentrations of arsenic.



Figure 1-25 HRSG Sulfur Deposits

The metal stack's internal surface temperature was often below the acid dew point of the stack gas because of natural heat transfer to the ambient air. The

acid dew point at that time was about 240°F assuming 5% of the sulfur is present as SO₃. Insulating the stack eliminated this cold surface for sulfur condensation. Also, removal of the gasification plant's gas/gas exchangers in early 1997 (see Section 1.3.4.4.1) increased the condensate temperature to the HRSG economizer. This increased the stack temperature from its previous range of 275°F ± 10°F to its current range of 315°F ± 5°F, well above the dew point. These steps reduced the deposition rate, but did not eliminate it. We believe the deposition rate was further reduced when the sulfur content of the syngas was lowered by improving AGR operation and installing the COS hydrolysis unit in response to the lower SO₂ emission limits in late 1998. However, this only lowered the acid dew point by 5°F to 10°F.

An additional obstacle is lack of any viable way to remove the deposits with the current hardware configuration. High pressure water washing is effective, but we have no sump or other means to catch and remove all the resulting acidic water. Consequently, the sulfur deposits remain in the HRSG and continue to grow, albeit at a reduced rate.

Raising the temperature alone will not be the solution to our problem, since the ferrous sulfur deposits occur as far forward as the HP Evaporator Section. Consequently, HRSG stack, tubes, and skin corrosion remains a concern, especially during long outages when the hygroscopic sulfur deposits tend to form a sticky goo in the back half of the HRSG. To address this concern, we are evaluating the cost of some approaches to further reduce the sulfur content of the syngas.

1.4.3.5.2 Valve (Steam) Leaks

Steam loss through valve leaks have periodically resulted in a loss of up to 3 MW of power from the steam turbine. The many relatively small drain valves are a common problem. We have replaced many of the original globe valves with metal seated ball valves. These valves, however, are not problem free, and we are currently evaluating the performance of alternative manufacturers to resolve this issue. The main saturated steam dump valve to the condenser has been a significant source of steam loss. This valve is used to control the pressure of the wet HP steam produced by the syngas cooler during gasifier startup. The water droplets in this steam make it very erosive, and it was impossible for this dump valve to maintain a tight shut-off during normal operation. It was the source of a 2.5 MW power loss. To eliminate this loss, we installed an automated upstream block valve that could maintain a positive shutoff during normal operation. This valve must be kept hot at all times with a small bypass steam flow to ensure that it will open promptly when needed.

1.4.3.5.3 Desuperheaters

The steam turbine materials limit the allowable inlet and reheated steam temperatures to a maximum of 1000°F. Desuperheaters spray boiler feedwater into the steam if it gets too hot. When the CT is firing syngas, we rarely have to operate the desuperheaters, because the CT exhaust temperature is relatively modest (1066°F) and a significant amount of saturated HP steam and some saturated MP steam from the gasification plant absorb the heat from the HRSG superheaters and reheaters. In fact, they were designed expressly for this operating condition. However, the situation is reversed on liquid fuel. The CT exit gas temperature on liquid fuel is higher, over 1100°F. Also, with the CT firing liquid fuel, there is not an import of steam from the gasifier, so the steam flow to the superheaters is relatively low. Under these conditions the boiler feedwater injected through the desuperheater sprays account for a good deal of the total steam flow to the steam turbine. However, the amount of spray flow is limited. We cannot desuperheat down to the saturation temperature, because erosion of the HRSG piping would result. We intentionally stay 50°F above saturation for this reason. Also, the system dynamics are extremely slow. This makes automatic control difficult, and the desuperheater controls are not particularly stable anyway. Consequently, we have to change load very slowly and manually (no operation on automatic dispatch) at high loads while on liquid fuel.

1.4.3.5.4 Stack Opacity Meters

The Polk operating permit required that a continuous opacity monitor be installed in the HRSG stack. Such monitors do function properly in stacks of conventional coal fired plants, since such stacks are typically rigid. However, HRSG stacks, such as Polk's, are much more flexible, so it was impossible to keep this monitor in alignment. The opacity, when operating on syngas, never approached the permitted 20% limit. Consequently, we were able to successfully petition the agency to discontinue use of the opacity monitor in lieu of periodic visual readings.

1.4.4 STEAM TURBINE

1.4.4.1 PROCESS DESCRIPTION

The steam turbine configuration is shown along with the HRSG in Figure 1-24 on Page 1-74. It is a double flow reheat unit with low pressure crossover extraction. The steam turbine generator is designed specifically for highly efficient combined cycle operation with nominal turbine inlet conditions of approximately 1,450 psig and 1,000°F with 1,000°F reheat inlet temperature. Output during normal full load operation on syngas fuel ranges between 120 MW and 135 MW, depending on ambient temperature and steam production and consumption in the gasification plant.

The outlet from the last stage of the turbine is condensed by heat exchange with circulating water from the plant cooling water reservoir. Condensate from the steam turbine condenser is returned to the HRSG's integral deaerator by way of the gasification plant, where significant condensate preheating occurs.

1.4.4.2 STARTUP AND OPERATION

Like the combustion turbine, steam turbine startup, synchronization, and load change are fully automated activities that are normally initiated through a signal from the distributed control system (DCS) in the main control room to the turbine's Mark V controls located in the ST PEECC. The valve sequences are not so complex as those of the combustion turbine, so problems are rare. However, when difficulties do occur, the same troubleshooting specialists are required.

1.4.4.3 SAFETY

There are no unique safety considerations associated with the steam turbine.

1.4.4.4 RESOLVED AVAILABILITY ISSUES

1.4.4.4.1 Planned Outages/Inspections

So far, periodic valve inspections have been the only required maintenance on the Steam Turbine. We have noted some blue blush buildup on the Main Steam Control Valve's stem and bushing assembly. Consequently, we perform valve tests nightly to exercise the Main Steam Control Valve along with the Left and Right Intercept Valves (the main steam control valves to the IP steam turbine).

The shell of the steam turbine will be removed for the first time during the major inspection in 2003. During this outage, we will check steam seals for rubs and internal diaphragm clearances. We have experienced three (3) high vibration (rubs) during Steam Turbine start ups. The resulting turbine rotor bow and vibration has most likely led to excessive steam turbine seal clearances and the need for significant sealing steam flows at low loads.

1.4.4.4.2 Generator Excitation Controls

October/November 1996, 4 days total

Two failures in the ST generator excitation controls occurred shortly after initial plant startup in 1996. The first failure was a result of loose bolting in the 480 Volt buss bar. The second problem was due to the excitation isolation breaker failing to close. The faulty breaker was redundant so it was simply removed. These problems have not recurred.

1.4.4.4.3 Main Breaker Fault

February 2000, 3 days

The ST main breaker failed to open following a turbine trip. This caused damage requiring 3 days to repair. The combustion turbine tripped during routine operation due to a false indication of a fire. Lack of CT exhaust heat to the HRSG lowered the main steam header pressure, causing the steam turbine controls to issue shutdown commands. The steam flow to the turbine stopped, and the controls sensed reverse power to the generator as usual for all normal ST shutdowns. Reverse power prompted issuance of the command to open the steam turbine generator breaker, again as usual. Normally, this would complete the combined cycle shutdown sequence. The faulty fire indication would then be corrected, the combined cycle would be restarted, and normal operation would resume. However, in this instance, the hydraulic oil accumulator which served the ST generator breaker had developed a leak. This caused the hydraulic pump to cycle on and off rapidly, eventually causing it to trip when its motor over-heated. The alarms were inadequate to bring the operators' attention to the problem. The resulting low hydraulic fluid pressure prevented the ST generator breaker from opening. Now the generator was importing power, turning it into a large induction motor without excitation. Operation in this mode results in rotor slippage which creates excessive heat that can be damaging. In an effort to try to get the breaker open, the grounding switch was accidentally activated, creating a phase to ground fault. The 230 kV switchyard breakers opened once they had sensed the fault. Fortunately the generator stator and rotor sustained no damage, and the breaker damage was minimal. The breaker was repaired and returned to service, the hydraulic accumulator leak was repaired, training was provided and signs were installed to prevent accidentally activating the grounding switch, and the associated alarms were improved.

1.4.4.4.4 Main Steam Control Valve Failure To Close

September 2001, 7 hours

The ST Main Steam Control Valve should close when the ST is taken off-line in conjunction with the ST main stop valve to prevent turbine overspeed in the event of a trip. This failed to occur on one occasion.

The normal process of taking the ST off line is to first bring the CT down to approximately 20 to 30 MW, allowing the load on the ST to drop proportionately. The main steam is then dumped to the Condenser until the Steam Turbine gets below 5 MW. At this point the ST trip button is exercised. The trip button dumps the hydraulic oil pressure to all of the steam valves, and steam flow to the turbine ceases. When the main generator breaker controls sense reverse power, they will open the breaker and the unit is off line. It is important to point out that tripping a unit does not mean that the breaker is forced open. If a valve sticks open and steam is still being

introduced to the ST, the unit stays connected to the grid. In this manner overspeed incidents are prevented.

On September 7, 2001, the unit appeared to shut down properly as the redundant main steam stop valve shut, and steam flow to the Steam Turbine ceased. Operators, however, noted that the Control Valve was open at approximately 12%. As the valve cooled, it closed by itself within a few hours. The valve appeared to stoke freely the next day, but nonetheless it was inspected. We found the valve stem to bushing tolerance was less than desirable, and observed a blue blush Fe_2O_3 buildup. Repairs were made while the gasifier was down and the unit was returned to service.

1.4.4.4.5 Condenser Vacuum Breaker March 2001, 6 hours

A control system component failed, causing the ST condenser vacuum breaker to open spontaneously during operation. The gasifier had to be promptly shut down, since the condenser could not accommodate all of the steam under these circumstances. The faulty card was replaced.

1.4.4.5 UNRESOLVED AVAILABILITY ISSUES

1.4.4.5.1 Generator Electrical Insulation

GE has observed deterioration of a specific adhesive used to secure the electrical insulation of generator rotors. This can lead to movement of the insulation which may cause high vibration and possibly a serious ground fault. That specific adhesive had been used in both of Polk's generators and higher than normal vibration was noted on the steam turbine generator. Inspection in the spring 2002 outage confirmed that the insulation was migrating in both the CT and ST generators. Repairs will be made in the spring 2003 major planned outage which will extend that outage an additional two weeks to six weeks.

1.4.4.6 OTHER ISSUES

There are no other outstanding issues related to the steam turbine and its generator.

1.5 UTILITIES AND COMMON SYSTEMS

1.5.1 GENERAL

Plant utility and common systems are often considered uninteresting and mundane. However, plant operation depends entirely upon utility and common systems functioning smoothly and reliably, and they account for a very significant fraction of the plant capital and O&M costs. Polk's utility and common systems have performed extremely well, as evidenced by the fact that they account for only 2 % of the plant's unavailability to date.

Polk's utility systems consist of the following:

- Electrical Distribution
- Control and Data Acquisition
- Auxiliary Boiler
- Propane
- Distillate Fuel
- Flare
- Instrument/Plant Air
- Water systems:
 - Well Water Supply, Service Water, Potable Water
 - Demineralized Water
 - Boiler Feed Water Circulation and Distribution
 - Circulating Pond Cooling Water
 - Fire Water
 - General Wastewater Treatment (See Section 3.2)

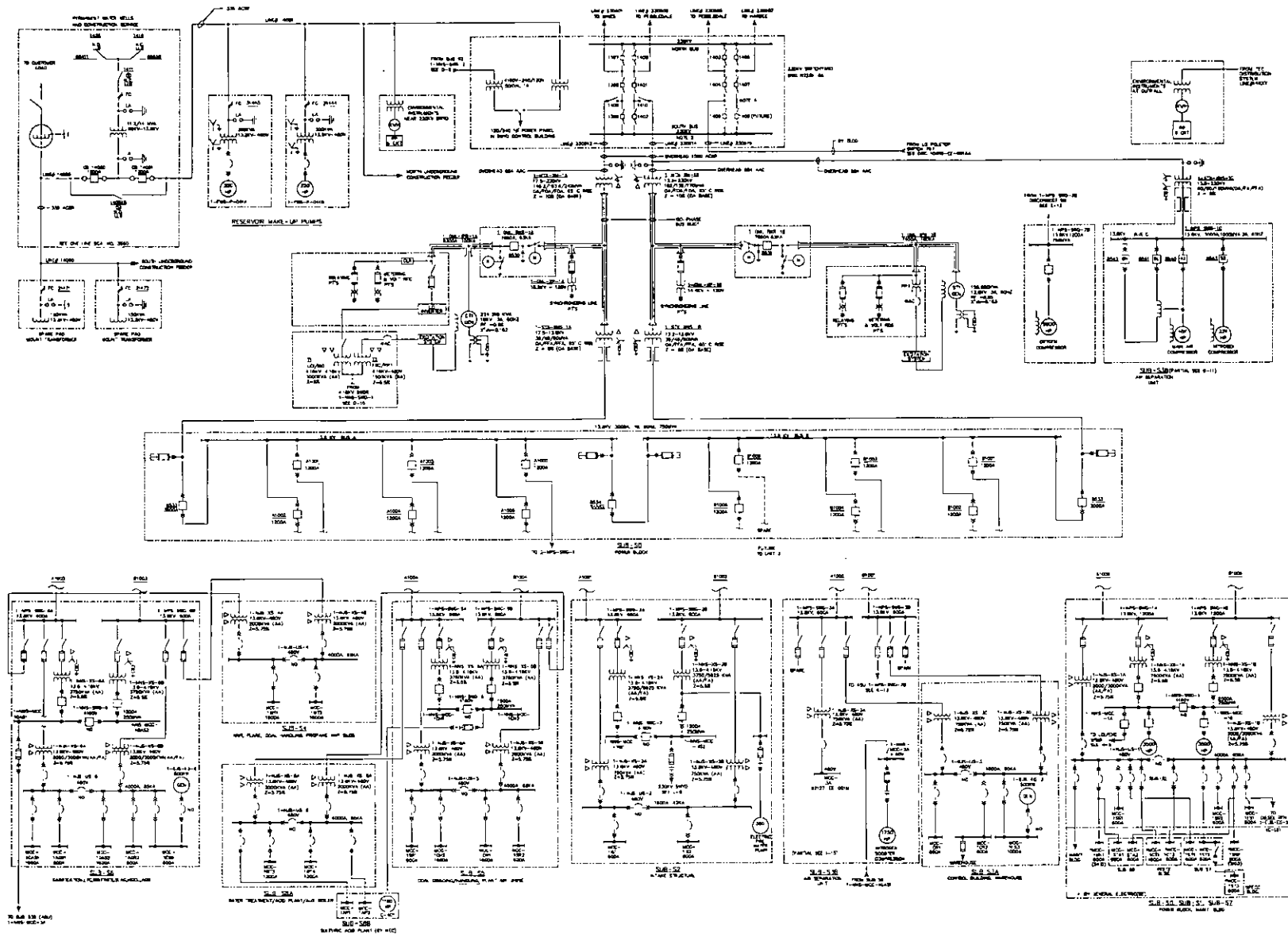


Figure 1-26 Electrical One-Line Diagram

1.5.2 ELECTRICAL DISTRIBUTION

1.5.2.1 PROCESS DESCRIPTION

Figure 1-26 is the overall one-line diagram for the Polk Power Station electrical system. For plant startup and periods when the plant is down, power is received from the 230 kV switchyard and is back-fed through the generator step-up transformers, while the generator breakers are in the open position. This provides power to the 13.8 kV station service transformers, which in turn feed the main substation S0. The substation S0 then distributes the power at the 13.8 kV level to the other substations, where the voltage is reduced to 4160V and 480V through auxiliary transformers. Most of the plant equipment, such as the combustion turbine static starting system, requires 4160v or 480v.

The air separation plant's main air compressor motor (MAC), the oxygen compressor motor, and the diluent nitrogen compressor motor are different from the rest of the motors in the plant. They run on 13.8kV because these motors have a high horsepower rating, and it is more efficient to run them at the higher voltage.

The power block 125VDC requirements are provided from two battery sources. One battery source is dedicated to the combustion turbine emergency lube oil pump and the emergency seal oil pump. The other battery source is for critical load supplies, such as the turbine control unit and the circuit breaker control power. The steam turbine has the same battery requirements as the combustion turbine. The steam turbine also uses a battery source to flash its field, unlike the combustion turbine that requires an outside AC power source for its field. Other 125 VDC loads throughout the plant are used in conjunction with uninterrupted power supplies. For example, the distributed control system for the plant uses an uninterrupted power supply, so that the internal control processing unit does not lose its memory or control functions.

The voltage rating for the combustion turbine generator is 18 kV, and its power output is 192 MW. The voltage rating for the steam turbine generator is 13.8 kV, and its power output is 130 MW. Each generator is connected via iso-phase bus duct to its respective generator step-up transformer through an SF6 generator breaker and disconnect switch. Bus duct taps are provided for connection to the station service transformers.

1.5.2.2 STARTUP AND OPERATION

During startup, power is back-fed through the CT generator step-up transformer or the steam turbine generator step-up transformer to power up the static-starting unit. Once the combustion turbine is up to speed and self-sustaining, the static starter is deenergized, and the generator can be synchronized to the 230 kV system by closing the 18 kV generator breaker. Similarly, when the steam turbine generator is up to speed, it can be synchronized to the 230 kV system by closing the steam turbine generator breaker.

Once the combustion turbine is started up and synchronized to the system, the combustion turbine can provide power to all of the station loads through the station 13.8 kV power distribution system.

The air separation plant has 3 synchronous motors. Because of the size of the compressors, we use synchronous motors so there is no rotor slippage. Slippage creates excessive heat in the motor rotor and inefficiency in the compressor. The MAC, our largest compressor, uses an autotransformer to decrease the initial voltage, allowing the MAC to be soft started. Once the motor has reached its full load speed, a DC field is induced into the rotor, which locks in the motor's speed with the grid frequency. A change in motor speed can only occur from a change in the grid frequency.

1.5.2.3 SAFETY

As a precautionary measure, because the ASU compressors have higher voltage motors, no one is allowed in the switch gear room while they are being started. This is to ensure that no one is injured if a fault were to occur while starting these compressors.

1.5.2.4 RESOLVED AVAILABILITY ISSUES

1.5.2.4.1 Generator Excitation Controls

2 Events: October and November 1996, 4 days total

Electronic component failures in the steam turbine's excitation controls occurred shortly after initial plant startup in 1996. These incidents are described in Section 1.4.4.4.2

1.5.2.4.2 St Main Breaker Fault

February 2000, 3 days

A complex sequence of events beginning with a false indication of a fire at the Combustion Turbine led to damage of the Steam Turbine Generator's main breaker which required 3 days to repair. The complete incident is described in Section 1.4.4.4.3

1.5.3 CONTROL/DATA ACQUISITION

1.5.3.1 PROCESS DESCRIPTION

The plant control and data acquisition systems consist primarily of a Bailey INFI-90 Distributed Control System (DCS), GE Mark V turbine controls, a Triconex Gasifier safety system, the PI data acquisition and retrieval system, and a limited number of other important local control panels.

The Bailey INFI-90 Distributed Control System (DCS) is a highly modular, microprocessor based system which provides both continuous and sequential control for most of the equipment at the station. Approximately 6800 inputs and outputs are connected to the DCS. Typical input signals include pressure, flow, and level indications, pump and motor vibration levels, process analyzer outputs, and relay contacts. The DCS contains 2 control loops, 1 for unit 1 and 1 for unit 2. Each loop has a redundant loop for backup. The operator interface is through touch screen color CRT and operator consoles located in the main control room. Appropriate and accurate control graphics on these consoles are critical for man-machine interface. With the operator interface, the operator can adjust unit loads, start and stop motors, and monitor and trend all plant operations. All plant alarming is directed through the DCS and indicated on CRT screens and printers.

Besides starting and stopping individual equipment and adjusting individual control valves, the DCS is used to integrate operation of the different plant areas and control overall plant output. The DCS automatically adjusts the gasifier oxygen and slurry flows while keeping them in an appropriate ratio, based on system pressure changes resulting from changes to the power demand set point or other disturbances. ASU's advanced control algorithms then make several adjustments in the ASU to provide the incremental oxygen to the gasifier and diluent nitrogen to the combustion turbine for the new load.



Figure 1-27 DCS Control Console

There are 19 Process Control Units (PCUs) containing the plant controller algorithms and their operating configuration. These units are located in the substations throughout the plant. The PCUs are what receive and send data back to the control room for monitoring and controlling through what is called exception reporting. Even if communication is lost between the operating station and the PCUs, the PCUs will retain the last commands that they received and still operate the plant. Only if the PCUs lose power will operation functions be lost

The system has been designed so that most equipment can be controlled from the control room graphics through the DCS. To do this, the DCS also incorporates communication with several local panels throughout the plant. Communication with these other control systems is via a combination of hard-wired connections to the network such as Ethernet or mod bus, for the most critical signals, and through RS-232 data links for less critical information transfer.

Key local plant control units are:

- Mark V combustion turbine control system
- Mark V steam turbine control system
- Gasification Emergency Shutdown System.

Other important local panels include:

- Flare Panel
- Gasifier Preheat Burner Panel
- Decomposition Furnace Panel
- SAP Preheat Furnace Panel
- GEHO Control Panel
- Slag Crusher Control Panel

The Combustion Turbine and Steam Turbine primary control utilizes the General Electric Speedtronic Mark V control systems. Unit control and protection is accomplished by using the Mark V in combination with sensors and devices mounted on the unit and its auxiliaries. Unit reliability is improved by using redundant sensors and devices for feedback, control, and protection of critical functions. Should one of the redundant devices fail, operation is not adversely affected. The connection of redundant devices to the control panel and their regulation by the control software were considered to be crucial factors in designing the Mark V. This fail safe approach results in a highly reliable control and protection system for the turbine.

The Mark V further improves unit reliability by using three redundant control processors. This triple modular redundant (TMR) design is capable of safely operating, controlling, and protecting a unit in the event of the failure of one of its control processors or control

processor components. The TMR design allows a single processor to be shut down and repaired without shutting down the turbine.

Finally, the Mark V TMR control system utilizes software implemented fault tolerance technology to eliminate the possibility of spurious trips. Each control processor in the TMR control panel makes its own determination of control and protection functions, based on separate inputs. The control processors individually vote the inputs used to make these determinations. Should one control processor fail to read an input correctly, its erroneous value would be out-voted by the other two processors.

The Gasifier Emergency Shutdown System is a Triconex Model V8 Triple Modular Redundant (TMR), Fault tolerant, microprocessor based system which provides equipment and personnel protection. It performs gasifier startup and shutdown valve sequencing and automatic gasifier shutdown initiation when it detects a potentially dangerous situation.

Approximately 250 inputs and outputs are connected to the ESD System. Many of the inputs to the system are triplicate measurements of the same process parameter, and many of the outputs are to dual solenoid valves in the field. ESD System solenoids are connected to control valve pneumatic signal lines, and, when deenergized due to a trip condition detected by the ESD program, set the control valves to their fail-safe positions.

The ESD system includes an engineering workstation for program development. The primary operator interface to the system is through a one-way serial communication link from the ESD system to the Distributed Control System (DCS). Required communication from the DCS to the ESD System is hard-wired. Communications from the ESD system to the DCS include transmitter readings, process alarms, first-out alarms, trip alarms, and system diagnostic alarms.

The TMR architecture of the ESD system with all functions of the system triplicated into three separate operational legs, provides the fault tolerance required for this safety application. No single point of failure will cause the system to fail. Extensive diagnostic capabilities will help maintenance personnel pinpoint fault in any one of the three legs of the system. TMR input/output boards can be replaced online without affecting the process and without the need for shutting down the system. The calculated system reliability is greater than 99.99%

The Data Historian consists of PI[®] and PI Processbook[®] software from OSI Software, Inc., operating on a dedicated computer with essentially infinite bytes of optical disk storage. It provides long term storage and live trending of all important data plantwide. All plant data since before initial operation in 1996 is immediately accessible. Such long-term storage of critical data is essential to identifying the degradation in equipment performance and troubleshooting hardware problems. Sufficient data is stored that is can be successfully used to troubleshoot most equipment failures and shutdowns. Engineers and maintenance schedulers rely on this information. Likewise, its versatile and user-friendly live data trending capability has almost entirely replaced DCS trending for operators and engineers monitoring the plant.

The plant control system also includes a sequence-of-events recorder which stores and prints discrete events (alarms, switch activation, etc.) to help identify the cause of plant shutdowns. Approximately 1000 points are inputted to the SOE system.

1.5.3.2 SAFETY

The key safety issues involving the control systems are to carefully develop and implement all protective logic, which is quite difficult in such a complex system. Appropriate attention must be paid to the failure position of critical automatic valves. Thorough process safety management (PSM) practices must be followed in the initial design, as well as for all process changes.

1.5.3.3 RESOLVED AVAILABILITY ISSUES

1.5.3.3.1 Control System Maintenance Errors

2 events: November 1996, September 1998; 6 Days Total

Specific work in progress on the DCS during plant operation caused forced outages. On one occasion, an on-line control configuration change caused a trip of the Main Air Compressor. On another, attempted replacement of a fuse in a PCU resulted in the trip of the condenser circulating water pump, resulting in condenser overheating, loss of vacuum, and some tube damage. To prevent recurrence, activity in the PCUs and off line downloads are limited to plant outages only. On line down loads are limited to non-critical equipment, when the plant is running, and all equipment when the plant is down

1.5.3.3.2 Other Resolved Issues

A number of events were identified in discussions of the major plant sections which involved control component failures or control system problems or weaknesses, many of which have been resolved. Also, the effects of some hardware failures have been mitigated, or the failures eliminated or their frequency reduced by the implementation of improved control system logic. Notable among these were the brittle failure of an oxygen line due to a fault in the original protective logic (Section 1.2.5.3) and some types of COS hydrolysis catalyst damage which will be prevented in the future by automatic bypassing of the reactor (Section 1.3.6.5.1).

1.5.3.4 UNRESOLVED AVAILABILITY ISSUES

1.5.3.4.1 Alarm Overload

Multiple alarms are often initiated in response to a single fault, resulting in confusion as to the root cause and diversion of the operators' attention. Also, many alarms are not properly prioritized, and there are a number of relatively meaningless "nuisance" alarms which should be eliminated. These were major concerns during initial operation, and a major initiative in 1997 improved the situation dramatically. However, it is still a problem, due in part to the many configuration changes that have occurred since then. Another

major initiative is in progress, since the plant configuration is now stable, and the important operating parameters are much better understood.

1.5.3.4.2 Component Aging

The control hardware is now over 6 years old. There have been some failures which we believe are simply due to component aging. This issue was discussed specifically in the ASU and slurry preparation sections, but such failures have also occurred in the MDEA system (main solvent feed pumps) and other areas. It will be a continuing cause of concern.

1.5.3.4.3 Continuing Logic Reviews

Best efforts were made in the plant design and control system implementation to prevent single point trips, i.e., outages resulting from failure of a single component. Despite these efforts, it is impractical to prevent all such trips due to prohibitive costs for making all critical components redundant and also due to the complexity of the system which makes identifying all such situations almost impossible. Typical recent examples of outages resulting from this type of failure are:

A slurry feed pump trip caused by an obscure single microswitch indicating a missing coupling guard. The guard was properly in place at the time.

A gasifier trip initiated by false indication of closure of one of the automatic slurry block valves. The three "independent" switches indicating the valve position were actually mounted on the same bracket due to space limitations, so they were not truly independent. The bracket shifted, causing two out of the three switches to indicate that the valve was not open.

A main air compressor trip when a thermocouple was disconnected as part of the preparations for a performance test. Although we had reviewed the configuration and determined that an appropriate default value would be inserted into the compressor's surge controls when the thermocouple was disconnected, other more obscure logic initiated the trip anyway.

We will undoubtedly find more examples of this type of problem through continued operation.

1.5.3.4.4 Trip Cause Indications

On a very few occasions, shutdowns have occurred as a result of equipment automatic trips when the root cause was not identified with 100% confidence. Two recent slurry feed pump trips are in this category. In many other cases, it takes longer to identify the root cause of trips than it should. This inevitably will lead to repeat trips due to the same cause until it is positively identified and rectified or, in the case of delays in problem diagnosis, will lead to missing hot restart windows and extended outages. There are two reasons for this weakness: 1) individual equipment is seldom provided from the factory with adequate first-out indication; and 2) the plant's sequence-of-events

(SOE) recorder which was intended to provide such information has never functioned properly. We are taking steps to address these weaknesses. A first-out panel is being designed and built specifically for the slurry feed pump, and a concerted effort is underway to make the SOE work properly.

1.5.3.5 OTHER ISSUES

1.5.3.5.1 Control Room Access To Mark V

One issue with our current configuration on the Mark V turbine control is the lack of a special operator interface, referred to as the <I>, in the control room. Operators are required to use the <I> on a frequent basis for troubleshooting and executing advanced control functions. A multi-unit <I> is currently being designed for installation in the main control room to access our CT and ST. The addition of this <I> will save time on diagnosing turbine problems and improve communication between the DCS operators and the specialists monitoring the <I> during particularly troublesome turbine starts and fuel transfers.

1.5.3.5.2 Control Valve Position Indication

Many critical control valves in the plant do not have a position indication available to the operators in the control room or in the data historian's records. This often makes it very difficult to determine if a problem is the result of a control valve being out of position or some other (process) problem. This has been the case several times for gasifier trips whose root cause was ultimately determined to have been control valve problems, particularly in the ASU. Lack of knowledge of black water control valve positions also exacerbates scrubber plugging problems following most gasifier startups. For almost all such critical valves, the valve position is known deep within the valve positioners' electronics, but it is simply not available to view or record, and it is remarkably difficult and expensive to extract this information. Nevertheless, one at a time, we are extracting this information as the critical valves are identified.

1.5.4 DISTILLATE FUEL

The plant has storage for 2,350,000 gallons of No. 2 fuel oil, which is used to fire the auxiliary boiler and the combustion turbine when gasification is down.

The fuel oil truck unloading pumps deliver the fuel oil from tank trucks to the fuel oil storage tank. From the fuel oil storage tank, the fuel oil flows directly to either the combustion turbine fuel forwarding skid and pumps or to the auxiliary boiler fuel oil pumps.

The unloading area is curbed and the storage tank area is diked. All rainfall and spills in these areas are collected and sent to an oily-water separation system.

There are no special startup or operating issues in this area.

There are no extraordinary safety considerations other than those normally associated with a large volume of combustible fuel. There have been no availability issues associated with the distillate fuel storage tank.

1.5.5 PROPANE

The plant has storage for 30,000 gallons of propane, which is used to fire the flare pilot lights, the gasifier preheat burner, the sulfuric acid plant preheat furnace, and the sulfuric acid plant decomposition furnace. Propane trucks use their pumps to fill the tank. Pumps are available for propane withdrawal during very cold weather, but they are typically only needed when the normal fill and withdrawal lines freeze up during tank refilling. The tank typically operates between 80 psig (winter) and 150 psig (summer). The liquid propane from the tank flows through a pressure regulator to an electrically heated vaporizer. The propane vapor flows through another regulator into the main header which operates at 35 psig, low enough to prevent condensation in the line on the coldest Florida winter nights. From there it is distributed to the flare which is a continual user, to the gasifier preheat burner used only in preparation for gasifier startup, and the sulfuric acid plant which is a heavy user prior to gasifier startup but which may continually use a small amount for temperature maintenance.

There are no special startup or operating issues in this area.

There are no extraordinary safety considerations other than those normally associated with a large volume of combustible fuel. There have been no availability issues associated with the propane storage tank and distribution system.

1.5.6 AUXILIARY BOILER

A packaged auxiliary boiler, rated at 100,000 lb/hr, provides medium pressure steam for plant startup and shutdown when the combined cycle is not operating. The auxiliary boiler fuel oil pumps deliver oil from the fuel oil storage tank to the boiler. Two dedicated feedwater pumps can deliver either demineralized water or circulating ST condensate to boiler's deaerator, making the auxiliary boiler package independent of most other plant systems. The steam it produces is used primarily for aspiration during gasifier preheating and for the ASU's temperature swing absorption dryer.

The Auxiliary boiler package has not been a source of downtime for the IGCC unit. The boiler's main problems have been due to down-time corrosion and intermittent short-term operation. Down-time corrosion has done extensive damage to the external tube surfaces. Intermittent short-term operation has precluded appropriate monitoring and care of the water chemistry, leading to internal tube corrosion as well. In late 2001, connections were provided to keep warm water circulating through the boiler at all times which should prevent the external tube corrosion and enable us to maintain the internal water within appropriate limits. A massive reconstruction is scheduled for early 2002 to replace or repair many of the boiler's worn tubes.

1.5.7 FLARE

1.5.7.1 PROCESS DESCRIPTION

The plant's flare burns gases which cannot be safely discharged to the atmosphere during plant startup and during upset and emergency pressure relief situations. The flare system is a critical plant protection system.

Multiple headers deliver the gases to a knockout drum located remotely from the process area. Pumps return water from the knockout drum to the grey water system. From the knockout drum, a single header delivers the gases to the 150' tall flare stack. Oxygen analyzers at the knockout drum and at the base of the flare stack verify the absence of oxygen in the system.

John Zink manufactured the flare tip. It is provided with a molecular seal to reduce air intrusion. Individual thermocouples and an infrared flame detector monitor the four propane fired continuous pilot lights, each equipped with a flame-front generator for ignition.

1.5.7.2 STARTUP AND OPERATION

The flare system is almost always available and continually purged with low pressure nitrogen, even when the gasifier is off-line. Whenever the system is opened for maintenance, pre-startup purging with nitrogen must be thorough.

1.5.7.3 SAFETY

Oxygen monitoring and exclusion from the flare system are critical. The flare KO drum is designed for 150 psig internal pressure to reduce the chance of its destruction if combustible gases combine with oxygen in an explosive mixture. A separate large nitrogen "dump" valve can flood the system with nitrogen if a potentially dangerous situation should develop. Operation in cold, high-wind conditions requires special attention. Whenever flaring of hot gas ceases under these conditions, the remaining hot gas in the header and KO drum can cool and contract, drawing oxygen in through the flare tip and leading to an explosive mixture. Under such conditions, the large nitrogen dump valve should be used.

1.5.7.4 RESOLVED AVAILABILITY ISSUES

1.5.7.4.1 Acid Gas Failure To Combust/Disperse At Flare January 1998, 3 hours

Following a SAP trip, acid gas failed to completely combust and disperse at the flare. Atmospheric conditions were such that a cloud of H₂S and/or SO₂ drifted over the process area at low level. Operators, alerted by many of the area alarms, promptly shut down the gasifier. No injuries occurred.

Following previous SAP trips, the staff had observed that adding 350 KSCFH of syngas to the acid gas promoted what appeared to be complete

combustion and reasonable dispersion of the combustion products from the flare. This event prompted an extensive dispersion study which confirmed this observation. The study also showed that a dangerous cloud could reach the process area very quickly, faster than the existing large diameter header system could deliver 350 KSCFH of syngas to the flare, unless the entire syngas stream were diverted. Instead, a smaller flare line through which the required 350 KSCFH of syngas could move quickly was routed to the outlet of the flare KO drum. Now, when operators open the syngas valve to this line as soon as the acid plant trips, this syngas can easily "win the race" to the flare, providing the necessary combustion and dispersion.

1.5.7.5 OTHER ISSUES

1.5.7.5.1 Flooded Flare KO Drum

During initial operation in 1996, raw syngas was often flared for extended periods of time, while the operators worked through the complex startup sequence provided in the design documents. This operation occurred at the design level setpoints of the syngas scrubbers, which we later discovered led to excessive water carryover. This water mixed with flyash, was carried to the flare KO drum with the syngas at a rate faster than the KO drum pumps could remove it. Consequently, on more than one occasion, water carried over to the flare stack, which was a dangerous situation. A supplemental KO drum was purchased and installed to accommodate extra water. At the same time, we learned the proper water level at which to operate the scrubbers to avoid excessive carryover and had begun streamlining the startup sequence. Consequently, the spare KO drum was never needed or used.

1.5.7.5.2 Plugged Acid Gas Flare Header

In the initial design, the pressure relief and startup flare lines carrying the ammonia gas from the ammonia stripper combined with the similar lines containing acid gas from the MDEA stripper and flowed through the "acid gas flare header" to the flare KO drum. When both ammonia gas and acid gas were flowing, the acid gas flare header plugged where the two streams merged, creating an extremely dangerous situation. The obstruction was probably comprised of salts formed by the ammonia in the ammonia gas and the CO₂ in the MDEA acid gas. The line could be unplugged with water (the hotter the better), but this exacerbated the flooding of the flare KO drum discussed earlier. This same situation occurred in the line to the SAP. Initially, the ammonia gas mixed with the MDEA acid gas before entering the burner controls for the decomposition furnace. This junction was also a common pluggage site. Ultimately, an independent burner control system and injection nozzle into the decomposition furnace was added for the ammonia gas.

We first tried routing the ammonia gas to the syngas flare header, but it plugged that header as well, creating an equally dangerous situation. We

were finally successful by routing the ammonia gas almost directly into the Flare KO drum. The drum is apparently large enough to accommodate the salt deposits which undoubtedly still form. Periodic operation of the main flare during startups seems to be sufficient to vaporize any deposits that form since there are no longer any signs of restrictions such as high back pressure in any of the flare headers.

1.5.8 INSTRUMENT/PLANT AIR

Plant and instrument air is supplied by two 500 HP, 1700 SCFM lubricated rotary screw compressors. One of the compressors was to be a 100% spare, but one must run full time and the other is often needed part time to meet the requirements of the plant. Instrument air is dried to a dew point of -40°F by a desiccant air dryer. Backup instrument air is supplied by letdown from the main air compressor in the ASU. The normal instrument and plant air header operating pressure range is 100 psig to 110 psig.

There are no special startup or operating issues in this area.

There are no extraordinary safety considerations associated with the plant and instrument air systems. There have been no availability issues associated with the plant and instrument air systems.

1.5.9 PLANT WATER SYSTEMS

1.5.9.1 SUMMARY

The plant water systems to be addressed in this section are:

- Well Water Supply, Service Water, Potable Water
- Demineralized Water
- Boiler Feed Water Circulation and Distribution
- Circulating Pond Cooling Water
- Fire Water

1.5.9.2 WELL WATER, SERVICE WATER , POTABLE WATER

1.5.9.2.1 PROCESS DESCRIPTION

Fresh water is supplied from four onsite wells. Two of these provide the process water requirements discussed here as shown in Figure 1-28. The other two well water pumps supply make-up to the cooling reservoir discussed later in this section. The typical analysis for this water from the Floridan Aquifer in the area is summarized in Table 1-2.

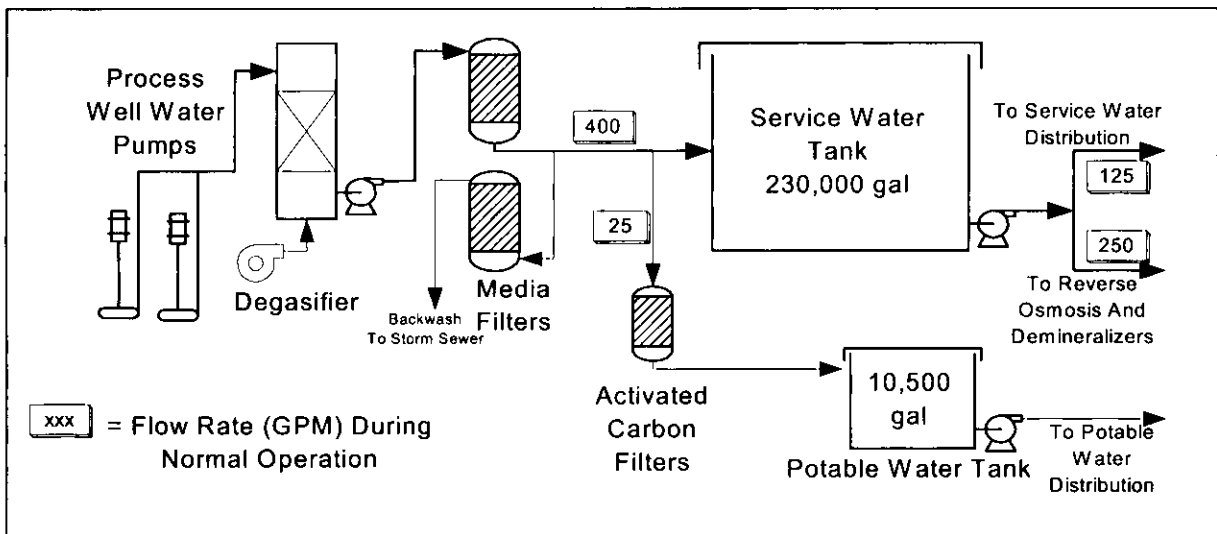


Figure 1-28 Well Water, Service Water, Potable Water

The well water is first chlorinated with hypochlorite and treated with sulfuric acid to promote removal of H₂S in the degasifier. The water is then degasified to remove H₂S. Filter feed pumps then send it through media filters and distribute the filtered water to the service water tank and the potable water system.

The service water pumps distribute service water from the 230,000 gallon service water tank to the service water system with stations located throughout the plant. A portion of the service water is sent to the demineralized water system. The service water system operates at pressures between 90 and 120 psig. This is not sufficient pressure to reach the top of the gasifier structure for slurry line flushing, so a booster pump is used when needed.

The potable water system provides drinking water and water for sanitary facilities, safety showers, and eyewash stations. It is filtered and further chlorinated with hypochlorite and pumped from the 10,500 gallon potable water storage tank to supply the system. A pressurized accumulator is used to maintain system pressure during power outages. Potable water specifications are in accordance with State of Florida Drinking Water Standard FAC_17-550.

Table 1-2 Well Water Quality

Parameter	Units	Well Water	Parameter	Units	Well Water
BOD20	mg/L	0	Gross Alpha	pCi/L	0
COD	mg/L	390	Total iron	mg/L	0.2
TSS	mg/L	33	Lead	mg/L	0
TDS	mg/L	237	Magnesium	mg/L	13.1
PH	units	7.66	Total Manganese	mg/L	0
Alkalinity	mg/L	110	Mercury	mg/L	0
Ammonia, nitrogen	mg/L	0	Nickel	mg/L	0
Antimony	mg/l	0	Nitrate	mg/L	0.26
Arsenic	mg/L	0	Nitrite	mg/L	0
Barium	mg/L	0.092	Phosphorus	mg/L	0.071
Benzene	mg/L	0	Potassium	mg/L	4.28
Beryllium	mg/L	0	Radioactivity, Ra 226	pCi/L	1.4
Cadmium	mg/L	0	Radioactivity, Ra 228	pCi/L	0
Calcium	mg/L	37.1	Selenium	mg/L	0
Carbon tetrachloride	mg/L	0	Silver	mg/L	0
Chloride	mg/L	13.4	Sodium	mg/L	15.7
Chlorine	mg/L		Sulfate	mg/L	39.5
Chromium	mg/L	0	Sulfide	mg/L	1.88
Chromium VI	mg/L	0	Surfactants	mg/L	0.06
Color, pt-co	units	20	Total organic nitrogen	mg/L	0
Conductivity	umhos/cm	330	Zinc	mg/L	0.014
Copper	mg/L	0	Copper	mg/L	0
Cyanide	mg/L	0	Cyanide	mg/L	0
Fluoride	mg/L	0.44			

1.5.9.3 DEMINERALIZED WATER

1.5.9.3.1 PROCESS DESCRIPTION

Service water for the demineralized water system is first purified in activated carbon beds followed by cartridge filters. It is then pumped to a reverse osmosis (RO) system which performs the primary demineralization. The RO system consists of two trains rated at 145 gpm each. The concentrate from the RO system is sent to the HRSG blowdown sump and from there to the cooling ponds. The permeate is decarbonated and pumped to leased trailer-mounted demineralizer beds rated at 300 gpm. These are changed out approximately every month. The water from the demineralizer beds is accumulated in a 400,000 gallon demineralized water tank. From there, it is pumped to the 117,500 gallon condensate storage tank for make-up to the plant's main steam and condensate system. The demineralized water storage tank must also meet the NO_x suppression water needs of the IGCC combustion turbine (Polk Unit 1) and the station's simple cycle combustion turbine (Unit 2) when they are operating on distillate fuel. Another simple cycle combustion turbine (Unit 3) is under construction which will have the same requirements.

The average demineralized water flow to the IGCC condensate storage tank is 200 ± 40 gpm. Of this total, 30 ± 15 gpm goes via the main feedwater pumps directly to the gasification plant for pump seals, instrument tap purges, and periodic flushes. The IGCC main steam and condensate system consumes the rest for steam drum blowdown to maintain steam drum water quality, for some inevitable small steam leaks through faulty traps, and to replace some minor routine steam condensate losses. All these water requirements increase during gasifier startup periods. The combustion turbines each use 275 gpm of water for NO_x suppression at full load on distillate fuel.

Demineralized water specifications are as follows:

Sodium, ppm as Na	0.005 maximum
Silica, ppm as SiO ₂	0.02 maximum
Total solids, ppm	0.05 maximum
Conductivity, µho/cm at 25°C	0.1 maximum
pH at 25°C	6 - 8

1.5.9.3.2 SAFETY

There are no special safety issues related to the demineralizer system other than the PPE required for dealing with standard water treatment chemicals.

1.5.9.3.3 STARTUP AND OPERATION

The 300 gpm demineralizer capacity cannot satisfy the normal 200 gpm IGCC requirement and simultaneously provide 275 gpm needed for NO_x suppression by either combustion turbine on distillate fuel. We must draw heavily on the inventory in the demineralized water storage tank to meet such simultaneous requirements. Some of

the common situations we encounter which require inventory withdrawal from the demineralized water storage tank are:

- When the gasification plant is starting up (its water requirements are then higher than normal) and the Unit 1 combustion turbine is operating on distillate in preparation for syngas fuel.
- When the IGCC is running normally and Unit 2 is required to operate on distillate fuel because natural gas is unavailable. This situation most commonly occurs in the winter.

This demineralized water production capacity limitation requires careful monitoring of the demineralized water storage tank inventory at all times and constant monitoring of demineralized water consumption to eliminate any waste.

1.5.9.3.4 AVAILABILITY ISSUES

The demineralizer system has not been the cause of any lost availability.

1.5.9.3.5 OTHER ISSUES

1.5.9.3.5.1 RO Membrane Fouling

We have had difficulty maintaining the correct chlorine level of the water to the RO system. Too much chlorine leads to rapid membrane deterioration and too little leads to biological growth which plugs the membranes. Consequently, the cost for membrane replacement has been high, and their capacity is often limited to half of their design rating.

1.5.9.4 BOILER FEEDWATER CIRCULATION AND DISTRIBUTION

1.5.9.4.1 PROCESS DESCRIPTION

The boiler feedwater/steam turbine condensate system consists of a large loop whose major elements are shown in Figure 1-24. The typical 200 gpm of losses from the loop are replenished by demineralized water from the condensate storage tank to the steam turbine condenser hot well as discussed in the previous section. The hot well is arbitrarily chosen as the starting point for the process description.

One of the two condensate pumps takes suction from the ST condenser hot well and sends the 1700±100 gpm of condensate at about 100°F through the following exchangers enroute to the HRSG deaerator:

- Steam Turbine Gland Steam Condenser
- Vacuum Flash Overhead Condenser (Gasification Plant)
- Steam Condensate Heater (exchange with raw syngas in Gasification Plant)
- HRSG LP Economizer (partially or totally bypassed)

The condensate enters the deaerator at about 315°F, having recovered approximately 180 MMBTU/Hr of low level waste heat. From the deaerator, the condensate descends into the HRSG LP Drum. The HRSG LP evaporator typically produces about 50 KPPH of steam. This is combined with another 40 KPPH from ST IP extraction and sent to the process plant users, the largest of which are the MDEA reboiler, the Ammonia Stripper reboiler, the 2nd stage brine concentration evaporator, and sometimes the ASU regeneration heater. Most of this condensate from these users is returned, but there are some water losses from this part of the cycle.

From the HRSG LP drum, the remaining water flows to one of the two main boiler feedwater pumps, referred to as the feedwater transfer pumps. The feedwater transfer pump sends the water at two pressure levels through the HRSG economizer banks to the HRSG HP and IP evaporators, the SGC HP and MP drums for the syngas coolers, and the Sulfuric Acid Plant MP drum for its waste heat boiler. An average of 35 gpm of IP feedwater is sent directly to the process plant and ultimately disappears into the grey water system. Steam drum blowdowns, leaks, and losses account for the rest of the normal 200 gpm makeup. The saturated steam from the various boilers in the plant returns to the HRSG for superheating and then flows to the steam turbine to produce electricity. The steam turbine condenser completes condensing the steam from the LP turbine and the condensate flows to the ST condenser hot well, completing the loop.

1.5.9.4.2 SAFETY

There are no special safety issues related to the boiler feedwater/condensate system other than the PPE required for dealing with standard water treatment chemicals.

1.5.9.4.3 STARTUP AND OPERATION

There are no unique startup or operation issues associated with the condensate system other than the limited make-up capability of the demineralizer system discussed in the previous section.

1.5.9.4.4 RESOLVED AVAILABILITY ISSUES

1.5.9.4.4.1 Feedwater Transfer Pump Failure April 1998, 4 hours

There have only been two brief outages totaling 9 hours attributable to the condensate system. In the first incident, April 1998, the feedwater transfer pump tripped, and the backup pump was out of service. The back-up pump was equipped with experimental magnetic bearings which were not reliable. The magnetic bearings were replaced with conventional bearings, and both pumps have been reliable since.

1.5.9.4.4.2 Hot Well Level Transmitter May 1998, 5 hours

In the second incident, May 1998, the level transmitter in the hot well failed, so the automatic water makeup valve did not open, and the system simply ran out of water. This has not recurred.

1.5.9.4.5 OTHER ISSUES

1.5.9.4.5.1 Condensate System Operating Pressure

The condensate circulating through the gasification plant, specifically through the steam turbine condensate heater where the condensate is warmed by heat exchange with raw syngas, operates slightly below syngas pressure. On one occasion, a leak developed in the condensate heater so syngas flowed into the condensate system, causing extremely low pH levels which made it very corrosive. For future systems with similar configurations, the operating pressure of the condensate should always be kept above the syngas pressure. In our case, we reconfigured one of the HRSG LP economizer recirculation pumps to serve as a condensate booster pump. This enables us to raise the condensate pressure above gas pressure if we ever again suspect a leak in this exchanger.

1.5.9.5 COOLING WATER SYSTEMS

1.5.9.5.1 PROCESS DESCRIPTION

The cooling/heat rejection system for the Polk Power Station is a cooling reservoir. Cooling of the water in the reservoir takes place primarily by evaporation, convection, and conduction from the reservoir surface. Peak observed water temperature is 87°F in the heat of the summer. Evaporation and seepage losses are made up primarily from two dedicated wells. The permitted total well withdrawal rate from all four wells (2 for the cooling reservoir and 2 for the service water system) is 2180 gpm. Typically 400 gpm is sent to the service water system during operation, but the annual average has been somewhat less at 335 gpm. This leaves 1845 gpm (annual average) available for the reservoir, but the actual usage rate has recently averaged just over half that (975 gpm). Part of the water to the service water system ultimately provides some reservoir make-up via various streams neutralized in the HRSG blowdown sump, e.g., steam drum blowdown water, filter backwashes, and weak acid from the SAP. Collected rain water runoff, treated oily water from the oily water system, and treated slag pile runoff also supplement the well-water makeup to the reservoir. Some water must be discharged from the reservoir to prevent the build-up of suspended solids since evaporation is expected to exceed seepage. However, water quality issues and the drought have precluded this recently.

The cooling reservoir has been constructed in areas which were mined for phosphate. The reservoir occupies an area of approximately 860 acres, including the areas of the

surrounding and internal earthen berms which direct the water in a serpentine path from the discharge structure back to the cooling water circulation pump intake structure. The total water surface area is approximately 727 acres and the water content is about 10,200 acre-feet. The berms were re-vegetated after construction, and the vegetation is being appropriately controlled and maintained to prevent future erosion.

Intake and discharge structures are constructed within the cooling reservoir to provide and subsequently discharge the cooling water. There are two "open loop" cooling water systems, both designed for a temperature rise of 25°F:

Steam Turbine Condenser: Approximately 130,000 gpm is provided to the steam turbine condenser by two 50 percent pumps.

Other Users: Approximately 40,000 gpm is provided for the remainder of the plant by three 50 percent pumps. Periodically all three of these pumps must be operated in parallel. The greatest heat loads on this system are imposed by:

- MDEA overhead condenser
- Lean MDEA cooler
- Ammonia stripper overhead condenser
- ASU Plant
 - Compressor intercoolers
 - MAC aftercooler
 - TSA Regeneration cooler
- Trim (Syngas) Cooler
- Open Loop heat exchangers

Four closed loop cooling water systems are provided for users that require higher quality water than that provided by the cooling reservoir:

- Power generation area
- Gasification and ASU general requirements
- Gasifier burner tip cooling
- Units 2 and 3

The clean closed loop water exchanges heat with the open loop circulating water in plate exchangers. Hayward self-cleaning filters protect the plate exchangers from being fouled by the open loop water.

1.5.9.5.2 SAFETY ISSUES

There are no safety issues associated with the circulating cooling water system which are not common in most Florida waterways.

1.5.9.5.3 RESOLVED AVAILABILITY ISSUES

1.5.9.5.3.1 Condenser Cooling Water Pump Start Failure July 1998, 36 Hours

There was only one availability impact attributable to the circulating cooling water system. In July 1998, one of the steam turbine condenser cooling water pumps failed to start, delaying gasifier startup for 36 hours while repairs were made.

1.5.9.5.4 OTHER ISSUES

1.5.9.5.4.1 Cooler Fouling at Extremities of Circulation System

The lean amine cooler is at the far end of the circulating pond water system and tended to accumulate much debris, such as sand and marine life residue. This fouled the tube surfaces, reducing heat transfer which had a very severe impact on the sulfur removal capability of the MDEA system in the summer. Corrosion also developed beneath the deposits, weakening the carbon steel tubes. Two steps were taken. First, a Hayward self-cleaning filter was installed on the cooling water supply to reduce the incoming debris. Second, the thinning carbon steel tubes were replaced with stainless steel, and the corroding water boxes were coated with a Belzona material to prevent further corrosion. Fouling and corrosion have not been issues for the lean amine cooler since. The MAC aftercooler is also somewhat at the end of a cooling water loop, and has also experienced occasional cooling water side fouling. Thought has been given to taking similar steps there.

1.5.9.5.4.2 Reservoir Water Quality

The cooling reservoir pH is typically between 8.5 and 9, while the permitted pH level for discharge is 6 to 8.5. A parameter calculated from the pH, un-ionized ammonia, is likewise slightly above permitted discharge concentration. It is not clear that these parameters are outside the normal range of naturally occurring local waters in areas previously mined for phosphate, such as the Polk site. However, any ammonia sent to the reservoir promotes algae growth which elevates both these parameters. Slag pile runoff and stormwater make their way to the reservoir after treatment. The recent modifications to the system reduce the ammonia concentration in the runoff by an order of magnitude. In addition, the current normal operating practice of recycling all flyash from the settler bottoms eliminates the most water-retentive slag which used to go to the slag pile, and this reduces the flow rate of the pile runoff by more than 50%. These two steps will virtually eliminate slag pile runoff as a potential source of ammonia to the reservoir (Section 1.3.5.6.1). A study is currently underway which will lead to installation of some system or systems to bring the reservoir water composition into permit limits for discharge.

1.5.9.6 FIRE WATER SYSTEM

Four firewater pumps supply firewater from the cooling water reservoir to the firewater distribution loop throughout the site. A low flow capacity motor driven jockey pump runs continuously to maintain firewater system pressure when demand is low. When the flow requirement increases beyond the jockey pump's capacity, the three main firewater pumps are sequentially started: first the motor driven pump, followed by the two diesel driven pumps.

The fire water system has not been the source of any unavailability or other problematic issues.

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CHAPTER 2 - AVAILABILITY

2.1 DEFINITIONS

This chapter provides key availability statistics for Polk Power Station Unit 1. The terminology can often be confusing, and unless the terms are well defined and understood, reported numbers can often be misinterpreted. The following simple definitions have been adopted throughout this report:

PERIOD HOURS (PH) Total hours in the period being evaluated
 1996, PH = 3984 Begins 0:00 on July 19 (day of first syngas production)
 2000, PH = 8784 Leap year
 All other years PH = 8760

SERVICE HOURS (SH)		
Section	Symbol	Hours in the period that:
IGCC	SH _{IGCC}	CT synchronized on syngas fuel
Combined Cycle	SH _{CC}	CT synchronized on either fuel
ASU	SH _{ASU}	ASU producing on-specification oxygen
Gasifier	SH _{GAS}	Oxygen flowing to the gasifier

RESERVE SHUTDOWN HOURS (RSH)		
Section	Symbol	Hours in the period that:
Combined Cycle	RSH _{CC}	CT is not synchronized but available for operation
ASU	RSH _{ASU}	ASU is not in service but available or starting up
Gasifier	RSH _{GAS}	Gasifier is available for startup, pending availability of oxygen or the combustion turbine

AVAILABLE HOURS AH = SH + RSH
 Total hours in the period the unit is either in service or available for operation

PLANNED OUTAGE HOURS POH
 Narrowly defined as the hours:
 CT is unavailable for combustion hardware or hot gas path inspections
 Gasifier is unavailable for annual refractory replacement or inspection

IN-SERVICE FACTOR SF = SH / PH x 100
 Percent of the period the unit is in service

AVAILABILITY FACTOR AF = AH / PH x 100 = (SH+RSH) / PH x 100
 Percent of the period the unit is available (in service or in reserve shutdown)

IGCC NET OUTPUT FACTOR = NET MWH ON SYNGAS FUEL / (SH_{IGCC} x 250) x 100
 Percent of power produced compared to maximum possible when firing syngas fuel.

SYNGAS UTILIZATION FACTOR = SH_{IGCC} / SH_{GAS} X 100
 Percent of time syngas is utilized in the CT when the gasifier is on-line.

2.2 KEY OVERALL STATISTICS

The three-fold commercial mission of Polk Power Station Unit 1 is:
 Operate as much as possible on less expensive solid fuel in the IGCC mode
 Be available to operate on distillate fuel when IGCC operation is not possible
 Be available to operate at all times of peak system demand (on-peak availability)
 (Note: Tracking of on-peak availability began only recently).

Figure 2-1 shows how Polk Unit 1 has served its mission. The corresponding data is in Table 2-1. Year-by-year key achievements and issues are discussed below.

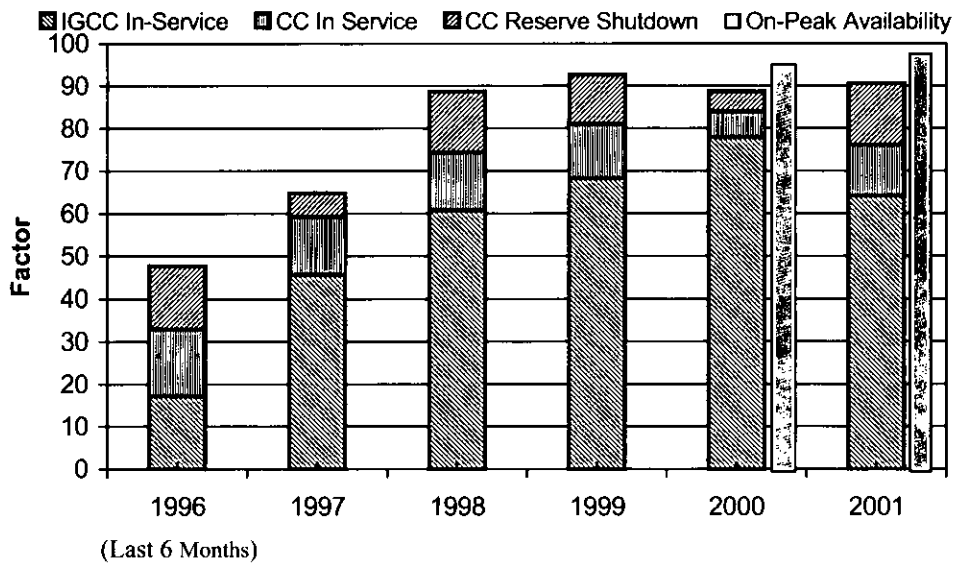


Figure 2-1 Key Availability Factors

	Gasifier In Service	IGCC In Service	Total In Service	Combined Cycle Availability	On-Peak Availability
1996	27.5	17.2	32.9	47.8	
1997	50.4	45.6	59.3	64.8	
1998	63.3	60.8	74.4	88.7	
1999	69.9	68.3	81.1	92.7	
2000	80.1	78.0	84.0	88.7	94.9
2001	65.4	64.2	76.1	90.6	97.7

Table 2-1 Key Availability Factors

1996

The last half of 1996 was the commissioning and very first commercial operation of the gasifier and integrated plant. All availability statistics were low in this period as expected. The ASU and combined cycle had been commissioned earlier (ASU in March, combined cycle in May). The period began with initial gasifier operation on July 19. Syngas was first fired in the combustion turbine on September 12, marking the first IGCC operation. Throughout the period, the ASU posed no significant problems, but the gasification plant suffered extensively from low carbon conversion (Section 1.3.5.6.1) and it began experiencing raw gas / clean gas exchanger pluggage (Section 1.3.4.4.1). The power block also had problems, among them an 11 day outage to replace failing third stage turbine bolts and a 16 day outage to deal with faulty combustor end cover brazing, both nonrecurring fabrication and design issues (Appendix B).

1997

Statistics improved marginally in 1997, thanks in large part to an outstanding 4th quarter with a 74% IGCC on-stream factor and a 91% combined cycle availability factor. A major contributor to this success was implementation of the hot restart procedure in October. This enabled us to restart the gasifier and return the combustion turbine to syngas fuel within 8 hours of a shutdown if its cause could easily be rectified. Previously, even the simplest of nuisance shutdowns required 24 to 48 hours for repair and reheat.

On the other hand, early 1997 was very trying. Two of the raw gas / clean gas exchanger failures had a devastating impact in this period since they not only forced gasification plant outages, but took the combined cycle out of service as well (Section 1.3.4.4.1). The exchanger failures and all related issues accounted for 95 days (17.8% of period hours) of gasifier down-time and nearly the same for the combined cycle. The only redeeming feature was that these forced outages obviated the need for a 10 day combustion inspection and provided the 30 days needed to replace the gasifier's startup refractory liner.

An additional 43 days (11.8% of the period hours) of gasifier down time in 1997 resulted from failures of two of the upper RSC seals, one of which was a fabrication defect accounting for 2/3 of the total time lost to RSC seal problems (Section 1.3.4.4.4). 1997 also saw the first ASU problem of any consequence, a 9.6 day outage (2.6% of period hours) due to a ruptured oxygen compressor suction line (Section 1.2.5.3).

1998

1998 was a year of solid improvement. The IGCC service factor posted a substantial 15% gain from 46% in 1997 to 61% in 1998, thanks to the elimination of the raw gas / clean gas exchangers and development of the hot restart procedure in 1997. Also, on the very positive side, the combined cycle availability factor in 1998 (89%) very nearly reached the average it has maintained for the last 3 years (91%), so one could say it had very nearly reached maturity.

There were, however, two serious issues which surfaced in 1998 and continued into subsequent years. The first of these was CSC pluggage (Section 1.3.4.4.2). The first indication of the severity of this problem was a CSC tube leak requiring a 30 day outage in May to repair. After this, the CSC's were cleaned 6 more times in 1998 alone to prevent further tube damage. These cleanings required an average of 4 days down-time, so the total impact of this problem in 1998 was about 54 days or 14.8% of period hours. The gasifier's high COS production was the second major issue which began impacting performance in 1998 (Section 1.3.6.4.1). In October 1998, SO₂ emissions limits were reduced from 518 lb/hr to 357 lb/hr. We could not meet the new lower limits with higher sulfur fuels we had been using because they produced more COS which is not removed by the MDEA acid gas removal system. A method of operating the syngas scrubbers to reduce the COS sufficiently led to downstream piping leaks. The piping finally required replacement during a 23 day outage in November. Additional previous outages totaling 8 days brought the total impact of this part of the COS problem to 31 days or 8½% of period hours. Subsequent outages resulted from problems with lower sulfur fuel blends which were used to keep within emission limits until COS hydrolysis was commissioned in late August 1999.

1999

1999 was a year of maturing plant operation which led to marginal improvement of both combined cycle and IGCC service factors. The 30 day gasifier refractory liner replacement in May was actually planned for the fall, but it was needed earlier (Section 1.3.4.4.3). It was done concurrently with the annual CT combustion inspection.

Factors having the greatest adverse impact on 1999 performance statistics were the continuing issues from 1998 - CSC cleanings (11 in 1999) and slag outlet pluggage due to the initial difficulty we had processing blends of low sulfur fuels. Substantial progress was made on both these issues in 1999. Modifications to the CSC inlet significantly reduced the pluggage rate in the latter half of the year. Furthermore, improved understanding of slag properties eliminated the problems with low sulfur coal blends, and, finally, COS hydrolysis was successfully commissioned in late August.

2000

2000 was the gasification plant's best year to date, resulting in an IGCC in-service factor of 78% and a gasifier in-service factor of slightly over 80%. 2000 included the longest gasifier runs to date (46.3 and 48.1 days), and the longest gasifier "campaigns" (59 and 73 days back-to-back). "Campaigns" are gasifier runs separated only by hot restarts of 8 hours duration or less. Enhancing this performance is the fact that it occurred through the summer peak, during which the gasifier was in service 91.3% of the time. 2000 on-peak availability was a very respectable 94.9%. Good performance of the COS hydrolysis unit which was commissioned in late 1999 and improvements made during 1999 in the CSC design to reduce pluggage laid the foundation for the excellent 2000 gasification plant performance. Further improvements were made to the CSC inlet design in early 2000, further reducing the pluggage rate so only 4 cleanings were needed in 2000.

The gasifier refractory floor and throat were replaced and a CT hot gas path inspection were performed during a 16 day outage in May. Weld failure in the ASU (Section 1.2.5.2) forced an additional 16.7 day outage (4.6% of period hours). The combined cycle suffered a slight availability reduction from the previous year due to a series of problems with the distillate fuel system (Sections 1.4.2.4.3 and 1.4.2.5), but still achieved a respectable 89% availability factor in 2000.

2001

In 2000, steps taken to reduce problems with the distillate fuel system began to pay dividends. The combined cycle returned to over 90% availability and the on-peak availability was a very commendable 97.7%. However, ASU and gasification plant performance were disappointing, resulting in a reduction of the IGCC in-service factor from 78% in 2000 to only 64% in 2001. A 28 day planned outage for refractory vertical hot face replacement and CT combustion hardware inspection in March was followed almost immediately by a 27.7 day forced outage due to failure of the ASU main air compressor 4th stage impeller (Section 1.2.5.1). Together, these spring outages accounted for 15% of the period hours. There was another 18.5 day outage (5% of period hours) in early fall to deal with issues associated with the gasifier's low carbon conversion and to remove the sootblower lances whose seals were beginning to leak (Section 1.3.4.4.4). Nevertheless, the outlook was bright by the end of the year since the major ASU and gasification problems experienced in 2001 were considered to be non-recurring and the combined cycle was performing well.

2.3 INDIVIDUAL SYSTEM STATISTICS

In Chapter 1 of this report, the plant was described as consisting of four main systems: ASU, Gasification, Power Block, and Common Systems. It was noted there that the common systems only contributed 2% to unavailability. Consequently, it is informative to look at the other three systems comprised of very diverse technologies to perhaps gain a better understanding of their relative strengths or weaknesses, at least as far as availability is concerned. This should provide some useful insights for designers of future plants who are starting with a more-or-less clean sheet of paper. This was done for two consecutive years of operation, the fourth and fifth years of commercial operation, October 1999 through September 2000, and October 2000 through September 2001. These correspond closely but not exactly with calendar years 2000 and 2001 discussed in the preceding paragraphs. Each system's performance index differed only slightly from year to year. The average results for the two years are shown in Figure 2-1 and numerical results are presented in Table 2-1 .

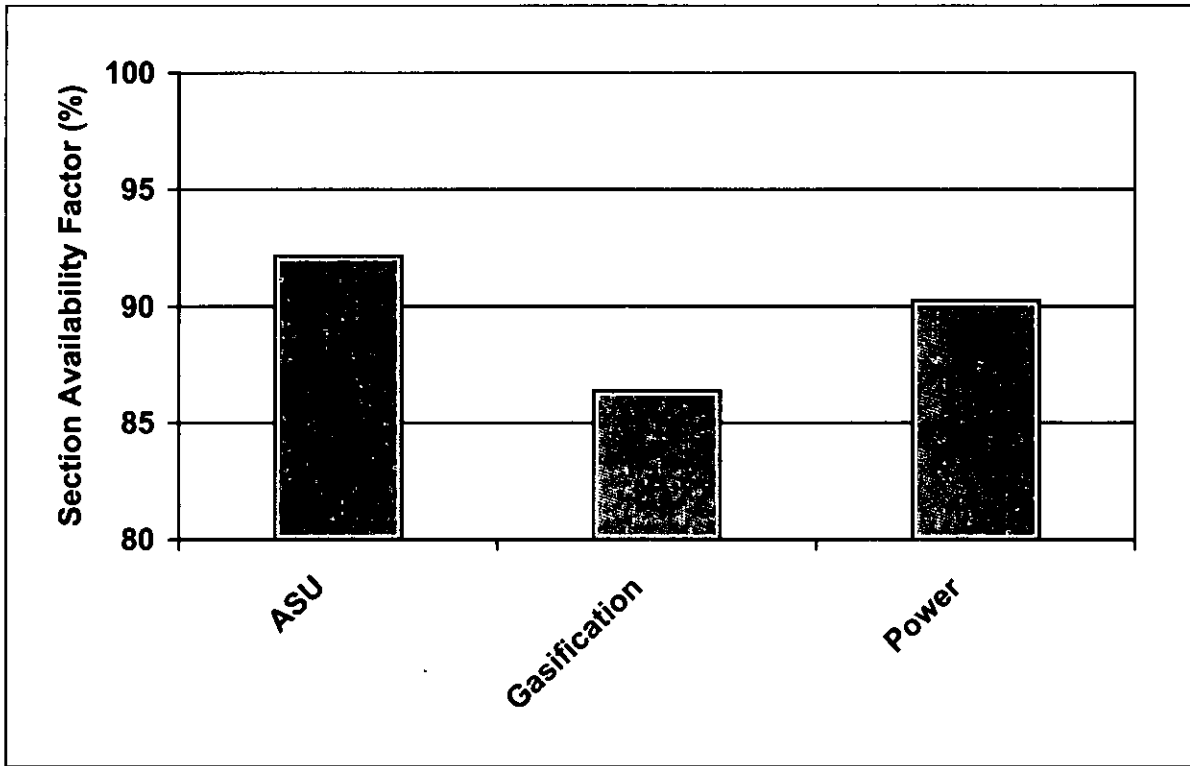


Figure 2-2 IGCC Subsystem Availability

	ASU		Gasification		Power Block	
	Year 4	Year 5	Year 4	Year 5	Year 4	Year 5
In-Service	80.5	73.3	77.8	71.0	81.0	81.4
Reserve Shutdown	13.4	17.2	10.9	13.2	5.6	12.5
Availability	93.9	90.4	88.6	84.2	86.6	93.9
Planned Outage	1.1	1.1	5.8	7.7	4.8	3.1
Unplanned Outage	5.0	8.5	5.6	8.2	8.7	3.0
Unavailability	6.1	9.6	11.4	15.9	13.5	6.1
Total	100.0	100.0	100.0	100.0	100.0	100.0

Table 2-2 IGCC Subsystem Availability Statistics

Consistent with expectations, gasification does have the lowest availability of the three main plant sections, but its 86% is very respectable for a single train plant considering all the component or subsystem failures that can force an outage.

The power block's 91% is slightly lower than one would expect from a combined cycle. This lower than expected value reflects the distillate fuel problems encountered in 2000 (See Sections 1.4.2.4.3 and 1.4.2.5).

The ASU availability was highest of the three, but its 92% is certainly lower than expected from this technology. During this time period, the ASU suffered failures of a column weld (Section 1.3.5.2) and the MAC 4th stage impeller (Section 1.2.5.1), very unique problems to say the least. Had this analysis been done for earlier years in Polk's operation, the ASU would have had a better showing.

2.4 IGCC NET OUTPUT FACTOR, SYNGAS UTILIZATION FACTOR

Polk Unit 1 is always dispatched on syngas to the extent of its capability. Consequently, the net power actually produced on syngas fuel compared to the rated output on syngas fuel (250 MW net), referred to here as the IGCC net output factor, is an unbiased indication of the derating the unit experienced in the IGCC mode. This data is shown graphically in Figure 2-3 and the numerical data is presented in Table 2-3. Also shown in the figure and table is the syngas utilization factor, the percentage of time the gasifier is on-line that syngas is being utilized in the combustion turbine. Syngas is not utilized in the CT for a brief period of time immediately following gasifier startup, and occasionally when short term repairs are being made to the combined cycle or to the gas cleaning system.

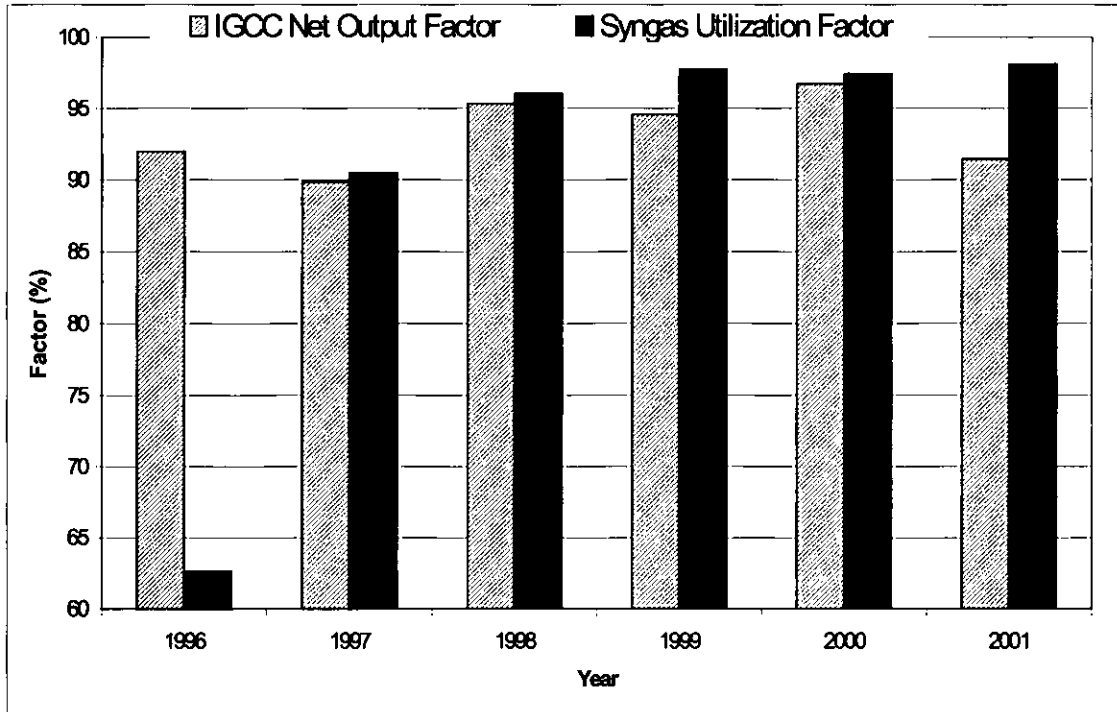


Figure 2-3 IGCC Net Output Factor and Syngas Utilization Factors

YEAR	GASIFIER ON-LINE (Hours)	CT ON SYNGAS (Hours)	NET POWER FROM SYNGAS (MWH)	IGCC NET OUTPUT FACTOR (%)	SYNGAS UTILIZATION FACTOR (%)
1996	1094.1	685.4	157566	91.95	62.64
1997	4417.1	3997.1	897701	89.83	90.49
1998	5548.2	5327.6	1269535	95.32	96.02
1999	6124.7	5987.4	1415757	94.58	97.76
2000	7033.1	6851.6	1656242	96.69	97.42
2001	5732.8	5622.7	1285470	91.45	98.08

Table 2-3 IGCC Net Output Factor and Syngas Utilization Factor

The low syngas utilization factor in 1996 (62.6%) reflects initial startup activities, which did continue to some extent into 1997. The slightly reduced IGCC net output factor in 1997 (89.8%) also reflected some of these startup activities and the somewhat ragged operation we experienced at times while dealing with the raw gas/clean gas exchanger plugging problems (Section 1.3.4.4.1). The slightly reduced IGCC net output factor in 2000 (91.5%) was a result of the performance deterioration of the ASU main air compressor and its aftercooler (Section 1.2.7.1). Other than this, these factors have been very respectably at or above 95%.

CHAPTER 3 - ENVIRONMENTAL PERFORMANCE

3.1 AIR EMISSIONS

3.1.1 SO_x

A key advantage of IGCC is low SO_x emissions even when utilizing lower cost high sulfur fuels. One key reason is that the sulfur species at point of removal in an IGCC plant are concentrated in the high pressure syngas. In contrast, the sulfur species are very diluted in the low pressure stack gas from conventional coal fired power plants. Table 3-1 compares key parameters for sulfur removal between the Polk IGCC configuration and a conventional coal combustion system. The comparison is for the same 250 MW net power production utilizing a 3.5% sulfur coal with a HHV of 13,000 BTU/Lb.

	Combustion	IGCC
Sulfur Compound Removed	SO ₂	H ₂ S
Steady State Heat Rate (BTU/kWh)	10,000	9,750
Sulfur in Coal (Lb/Hr)	6730	6562
Sulfur in Gas (Lb/Hr as S)	6394	6234
Gas - Description	Stack Gas	Syngas
Gas Flow (KSCFH)	32,600	7,000
Gas Conditions	1 psig, 200°F	320 psig, 100°F
Gas Flow (KACFH)	39,000	330
Gas ACF Flow Ratio (Combustion/IGCC)	39,000 / 330 = 118	
Sulfur Compound Partial Pressure (psia)	0.036	3.5
S Partial Pressure Ratio (IGCC/Combustion)	3.5 / 0.036 = 98	

Table 3-1 Sulfur Removal Parameters – IGCC vs. Coal Combustion

From Table 3-1, the coal combustion system stack gas flow (ACFH) is over 100 times more than the syngas flow, leading to much larger sulfur removal equipment for the conventional plant compared to IGCC. Furthermore, the partial pressure of the sulfur compound to be removed in IGCC is almost 100 times higher than in the combustion system which is conducive to higher removal efficiency for IGCC. 97.5% sulfur removal (Polk's permit level) is normally achieved in IGCC systems while 95% removal efficiency, although possible, is difficult to achieve in conventional coal-fired power plants. Even higher removal efficiencies are possible for IGCC at some additional cost, while much more than 96% removal would be prohibitively expensive for conventional technologies.

Figure 3-1 and Table 3-2 show the sulfur distribution and the removal and recovery steps at Polk. This sulfur data shown is from the same test period used to generate the overall plant performance data presented in Chapter 6, Sections 6-1 and 6-3.

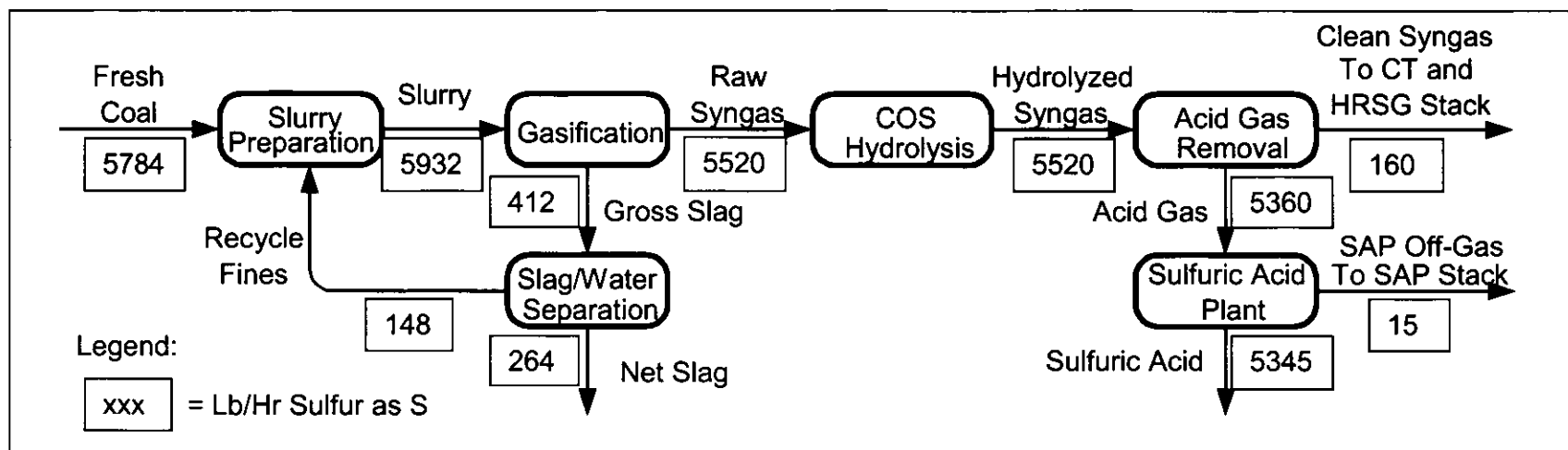


Figure 3-1 Sulfur Distribution

STREAM	SULFUR (LB/HR AS S)	NOTES
Fresh Coal	5784	3.0% (wt dry basis) sulfur in fresh coal
Recycle Fines	148	2.2% (wt dry basis) sulfur in recycle fines
Slurry	5932	3.0% (wt dry basis) sulfur in slurry solids
Gross Slag	412	7.0% of the sulfur in the slurry solids goes to the char in this case.
Net Slag	264	1.1% (wt dry basis) sulfur in net slag
Raw Syngas	5520	5% as COS, 95% as H ₂ S
Hydrolyzed Syngas	5520	0.2% as COS, 99.8% as H ₂ S; 96.6% COS Hydrolysis Conversion Efficiency
Acid Gas	5360	Virtually all H ₂ S; 97.1% AGR Sulfur Removal Efficiency
Clean Syngas	160	5.4% as COS, 94.6% as H ₂ S; yields 300 Lb/Hr SO ₂ +33 Lb/Hr H ₂ SO ₄ in HRSG stack.
Sulfuric Acid	5345	99.7% sulfur recovery in SAP; yields 200 TPD of H ₂ SO ₄ , 99.7% of which is sold.
SAP Off-Gas	15	In the form of 29 Lb/Hr SO ₂ plus 0.8 Lb/Hr H ₂ SO ₄ in SAP Stack

Table 3-2 Sulfur Distribution

The following comments on removal efficiency relate to the sulfur balance presented in Table 3-2:

- In this case, 7% of the sulfur in the slurry solids goes to the slag leaving the gasifier. This can be slightly over 10% if the per pass carbon conversion is low. The amount of sulfur which ultimately ends up in the net slag is reduced by recycling fines. In this case, recycling 57% of the settler bottoms resulted in 4.6% of the feed coal's sulfur appearing in the net slag.
- Over 96% of the COS in the raw syngas was converted to H₂S in the COS hydrolysis reactor in this case. This conversion efficiency is slightly better than normal since the catalyst was very fresh when this data set was taken. Conversion is typically between 85% and 95%.
- In this case, the MDEA acid gas removal system removed about 97.5% of the H₂S from the raw syngas. The solvent appeared to be foaming slightly when this data was taken. Such minor upsets occur periodically. 98% or higher H₂S removal is sometimes achieved under optimum conditions.
- The sulfuric acid plant consistently recovers over 99.5% of the sulfur it is fed, almost all as 98% sulfuric acid which is sold. This case is typical.

Permitted discharge limits and typical values of sulfur air emissions from Polk's two stacks (HRSG and Sulfuric Acid Plant) are summarized in Table 3.2

	HRSG Stack		SAP Stack	
	Typical Emissions	Permit Limit	Typical Emissions	Permit Limit
SO ₂	300	357	29	33 ^{1/}
H ₂ SO ₄	33	55	0.8	1.2 ^{1/}

^{1/} Permit limit is 4 lb SO₂ and 0.15 lb acid mist per ton of 100% H₂SO₄ produced. This equates to 33 Lb/Hr SO₂ and 1.2 Lb/Hr Acid Mist @ 200 TPD of 98% sulfuric acid produced, the acid plant's design capacity.

Table 3-3 SO₂ and H₂SO₄ Emissions (Lb/Hr)

SO₂ from the HRSG stack accounts for over 85% of the sulfur emissions to the air. Total SO₂ emitted from the HRSG stack when Polk was operating on syngas fuel through the end of 2001 has been 5205 tons which contained 2603 tons of sulfur. These data were officially reported to the Florida Department of Environmental Protection (FDEP) in the station's Annual Operating Reports. Table 5-1 (coal tonnage) combined with Table 5-3 (coal composition) indicate that the coal consumed at Polk during that time contained a total of 67,700 tons of sulfur. Overall 3.8% of the coals' sulfur has been emitted from the HRSG stack as SO₂. HRSG stack SO₂ emissions were reduced significantly when COS hydrolysis was commissioned in October 1998 (see Section 1.3.6.4.1). Consequently, current HRSG stack SO₂ emissions as a fraction of the coal's sulfur are lower than this overall average, more consistent with the 2.6% of the coal's sulfur reflected in Table 3-2.

3.1.2 NO_x

At Polk, as for most IGCC systems, all of the coal's nitrogen is converted to nitrogen gas (N₂) or compounds such as ammonia which are removed from the syngas before it is burned in the CT. Consequently, there is no fuel-bound nitrogen to form NO_x, and all NO_x emissions are from "thermal" NO_x generated at the turbine's elevated combustion temperatures. Thermal NO_x formation is mitigated in the Polk CT combustors by diluting the syngas fuel with nitrogen, thereby lowering the local flame temperature. NO_x is usually correlated with the LHV (BTU/SCF) of the syngas plus diluent N₂ mixture as shown on Figure 3-2.

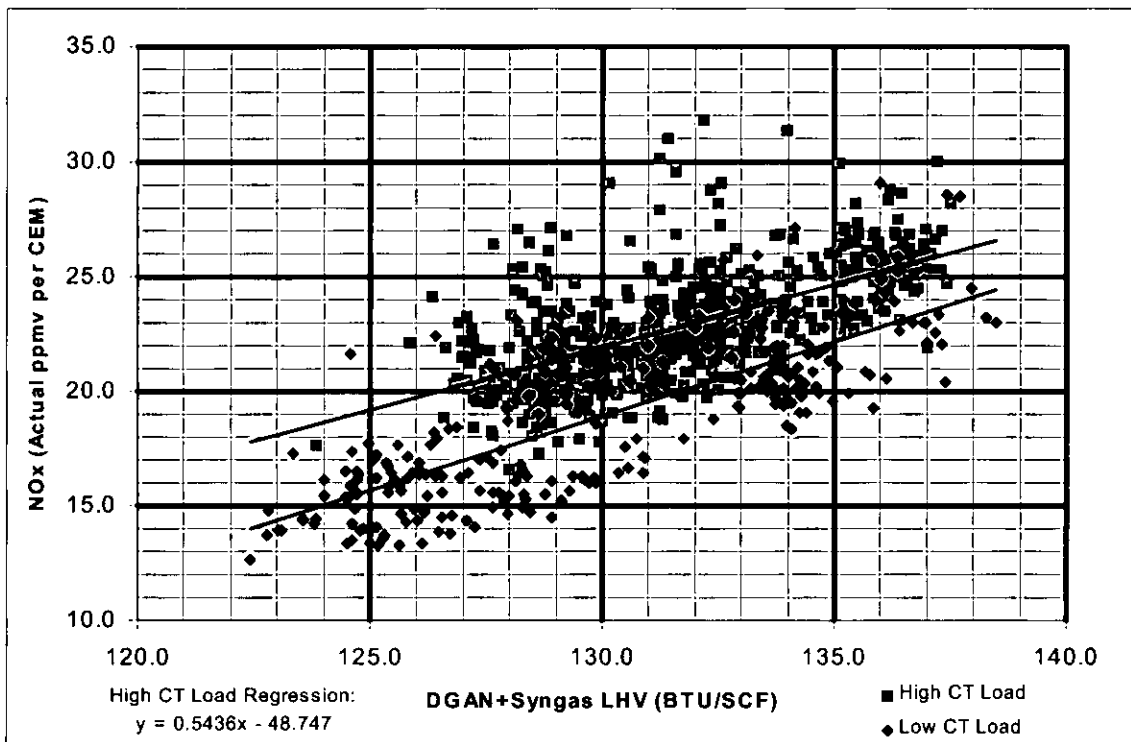


Figure 3-2 NO_x vs. Syngas + DGAN Heating Value

Figure 3-2 contains data through much of 1998 on several coals. It shows the expected trend for lower NO_x at lower syngas + diluent LHV. NO_x concentration averaged 3.5 ppmv higher at high CT load (> 184 MW) than at lower loads for the same gas mix LHV. Ambient temperature and gas composition also have an impact on the NO_x concentration.

Polk's NO_x permit limit is expressed not as actual Lb/Hr nor actual concentration, but rather as a concentration of NO_x on a dry basis corrected to 15% oxygen. The adjustment factor from actual concentration to the corrected concentration is variable due to changes in the stack gas composition, but it typically ranges from

0.65 to 0.70. The current HRSG stack limit is 25 ppmvd NO_x on this corrected basis which is equivalent to about 35 ppmv actually measured in the stack gas (the units used on Figure 3.2). The data in Figure 3-2 is well within the permit limit. The permit limit is also equivalent to about 220 lb/hr NO_x or 0.9 lb/MWH.

Polk's NO_x emissions (typically about 0.7 Lb/MWH) are a fraction of those from conventional coal fired power plants equipped with low NO_x combustion systems. Nevertheless, as of June 2003, the NO_x emission permit limit is being revised downward to 15 ppmvd (corrected basis) or about 21 ppmv (actual stack measurement). From Figure 3-2, it appears the syngas will have to be diluted to about 122 BTU/SCF to meet this limit. This will require an additional capital investment for plant modifications.

3.1.3 PARTICULATES

Polk's particulate emissions at 0.037 lb/MWH are about 5% of those from conventional coal-fired plants equipped with electrostatic precipitators. The Polk permit particulate emission limit is 17 lb/hr or 0.068 lb/MWH. Particulate emissions are so low for much the same reason that SO_x emissions are low. Syngas volumetric flow is very low relative to stack gas from conventional plants so intensive liquid scrubbing and filtration is affordable. It is also necessary since particulates in the syngas fuel could damage the combustion turbine by erosion and/or deposition. The syngas at Polk is subjected to 2 filtration steps and no less than 15 stages of intense liquid/gas contact.

3.1.4 OTHER AIR EMISSIONS

The HRSG stack has been tested annually for volatile organic compounds (VOC) and CO. The permit limit for VOC is 3 lb/hr, and average results have been 0.02 lb/hr. For CO, the permit limit is 99 lb/hr and the results have averaged 7.2 lb/hr. The stack was sampled for mercury once, and about half of the coal's mercury was detected. Mercury removal from syngas is proven technology, and we will be evaluating potential system configurations to accomplish this should it be required in the future.

3.2 WATER CONSUMPTION AND DISCHARGE

Figure 3-3 shows the main water supply and water treatment systems at Polk. One set of well water pumps provides 335 gpm (annual average) to the plant for makeup as service water and demineralized water (Section 1.5.9.2). Other smaller water sources to the plant are 30 gpm from moisture in the inlet air to the air separation plant and about 35 gpm in the feed coal during operation. 85 gpm is consumed by the coal gasification reactions and 15 gpm leaves with the slag. The remainder, about 300 gpm on average during operation, ultimately goes to

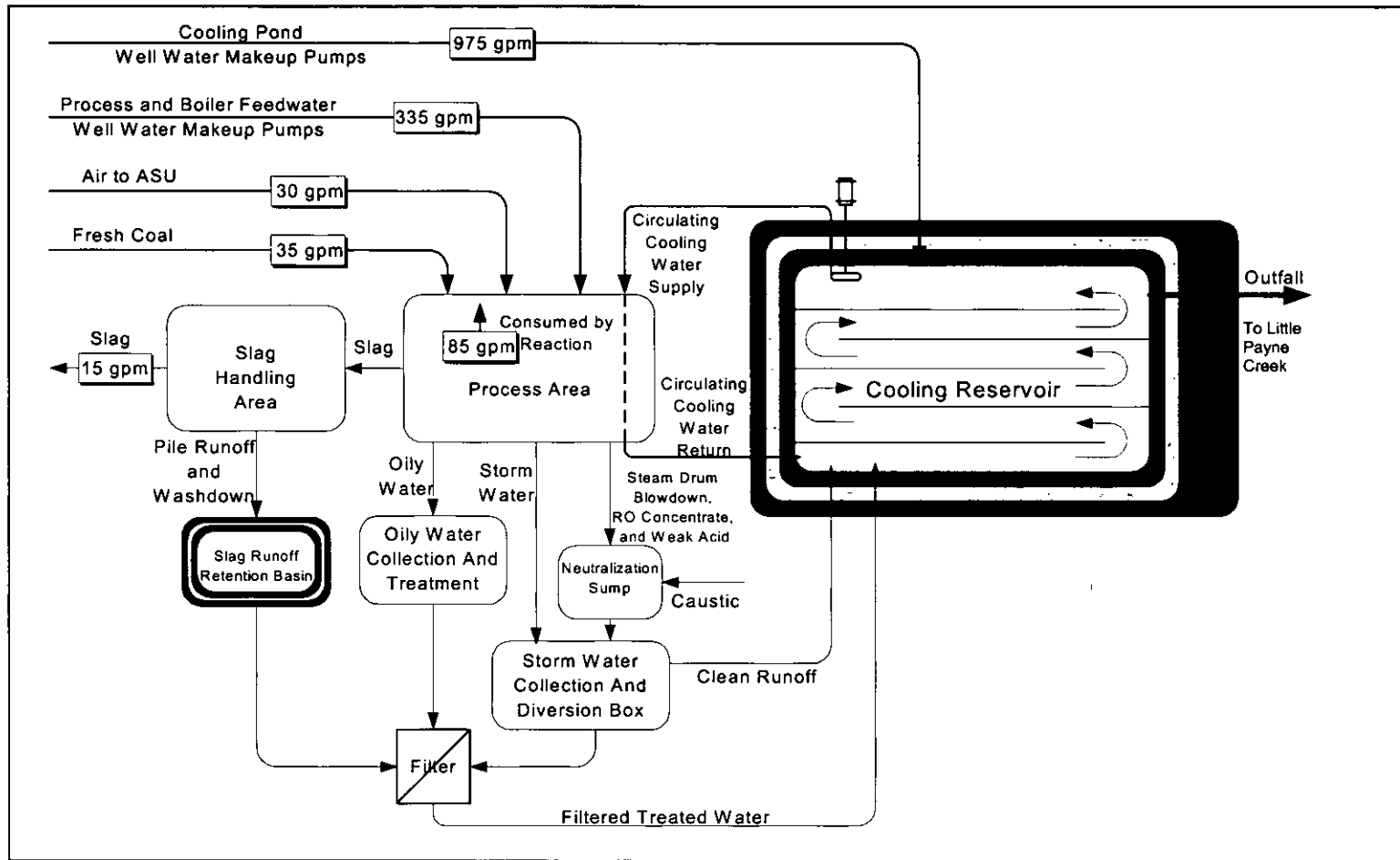


Figure 3-2 Water Supply, Treatment, And Discharge

the cooling reservoir. Most of this is blowdown from steam drums and concentrate from the reverse osmosis system. There is also a small weak acid stream from the sulfuric acid plant which could help adjust the pH of the cooling reservoir to a more desirable level if the operating permit did not require its neutralization before it is sent to the pond. The only "process" water which goes to the pond is currently about 5 gpm of slag pile runoff after filtration. The process has recently been reconfigured to strip this slag water of ammonia and eliminate chlorides (Section 1.3.5.6.1, items 5 and 6). All other process water is treated in the brine concentration unit and recycled (Section 1.3.5.1).

Joining this 300 gpm from the plant to the cooling reservoir is an additional 975 gpm (annual average) from another set of well water pumps which feed the cooling reservoir directly, plus a variable amount of rainfall.

The heat duty on the cooling reservoir is typically 1,000 MMBTU/Hr, 9% from gasification, 16% from the ASU, and 75% from the steam turbine condenser. This heat is dissipated by a combination of evaporation, convection, and conduction. Because of the evaporation and since the well water used for makeup contains 200 to 300 ppm of dissolved solids, some provision for blowdown from the pond is necessary to prevent dissolved solids from building up. Also, at times, heavy rainfall could cause the pond to overflow. The Polk Power Station (PPS) has been issued a State of Florida Industrial Wastewater Facility Permit under the provisions of Chapter 403, Florida Statutes, and applicable rules of the Florida Administrative Code. The permit constitutes authorization to discharge cooling reservoir blowdown water and storm water indirectly to Little Payne Creek, a Class III fresh water stream, regulated under the National Pollutant Discharge Elimination System (NPDES).

Since the startup of the power plant in 1996, reservoir blowdown has occurred intermittently. Tampa Electric suspended the discharge of blowdown since early 2000 due to a water quality problem in the reservoir, specifically the reservoir water quality does not meet discharge quality limits for pH, dissolved oxygen, chemical biological oxygen demand, and unionized ammonia (primarily a function of the water pH). Available data indicates that the growth of naturally occurring algae in the reservoir is a significant contributing factor to the water quality problem. Also, in the past, the slag pile runoff may have exacerbated the effect of this natural phenomena to the detriment of the pond water quality. Studies are under way to determine how best to return the cooling reservoir water parameters to compliance levels for discharge.

3.3 SOLID WASTE

The solid wastes from the Polk Power Station which are somewhat unique to an IGCC plant are slag, ammonium chloride, used filters, and spent catalysts.

Polk Power Station IGCC always generates slag from the coal feedstock during operation. Slag has been the plant's most troublesome solid waste by far. The slag consists of the non-combustible mineral matter of the coal along with unconverted carbon. Slag composition and yield is provided in Section 7.2. The gasification system was initially estimated to generate slag at a maximum rate of approximately 210 tons per

day on a dry basis. The slag was also initially classified as nonhazardous and non leachable and was to be marketed for various off site commercial uses such as abrasives, roof material, industrial filler, concrete aggregate, or road base material. A slag storage area was provided to accommodate periods when the slag by-product could not be sold in a timely manner. The area was designed to accommodate slag generated by approximately one year of operation of the IGCC unit at full capacity. Low carbon conversion of the gasifier sometimes resulted in three to four times more slag production than design (Section 1.3.5.6.1). This coupled with the inability of Tampa Electric to market the slag resulted in a large amount of slag being accumulated on site. The following key steps have been taken to reduce this stockpile:

- Some of the slag was sent to a Class I landfill to provide working space
- A second temporary on-site storage area was permitted and is being operated until the excess stored slag is marketed and/or consumed
- A contracted firm that specializes in coal combustion by-products is cleaning and separating the slag into its three useful components: the glassy frit which is being marketed to the cement industry, a fuel component which is being utilized in Tampa Electric's Big Bend Station, and a fines fraction which is being stockpiled for internal consumption at Polk.

Besides these steps, the actions described in Section 1.3.5.6.1 have reduced the net slag production rate to near the design rate and have dramatically improved its quality by reducing the ammonia and chloride content of the surface moisture. Facilities for complete on-line separation and internal recycle of the fines and fuel fractions are planned for the near future so all net slag production will be marketable.

A second solid waste stream generated at Polk is ammonium chloride derived from the coal's chloride content. It is produced in a brine concentration system described in Section 1.3.5.1. Also see Section 7.4 for its composition and general properties. Presently nearly 20 tons per month are produced and disposed of in a Class I landfill at approximately \$35 per ton.

In addition, filters in various systems must regularly be changed, which generates additional small quantities of solid waste. Most spent filters are from the MDEA acid gas removal system. The filter catch is primarily iron oxide or iron sulfide corrosion products. These amine filters are disposed of as a non-hazardous waste at a cost of \$65 per 55 gallon drum. About 2 drums per week are filled with spent filters during normal operation. Two to four more are filled with spent filters following each startup since the thermal contraction and expansion dislodges scale from the equipment.

Finally, catalysts in the sulfuric acid plant and COS hydrolysis systems must be changed periodically. The COS hydrolysis catalyst is non-hazardous, and disposal cost is about \$250 per ton for 10 to 20 tons per year, part of the total bed loading. The sulfuric acid plant catalyst is considered a hazardous waste, and its disposal cost is \$550 / cubic yard for 5 to 10 cubic yards per year.

CHAPTER 4 - COST

4.1 Capital Costs

The capital cost for each major section of the Polk Power Station IGCC is shown in Table 4-1. All project costs except interest during construction are included.

AREA or ACTIVITY	Actual Cost (\$000)	Escalated Cost To Mid-2001 (\$000)	Adjusted Escalated Cost (\$000)	Adjusted Escalated Cost (\$/kW)
Air Separation	35,067	36,795	37,580	150
Gasification	129,810	136,281	121,799	487
Cold Gas Clean-up and Sulfur Recovery	31,517	33,064	37,000	148
Hot Gas Clean-Up	23,271	24,350	0	0
Power Generation	104,156	112,755	112,181	449
Plant Water Systems	24,504	25,505	26,303	105
Electrical In-Plant Distribution & Switchyard	29,028	30,282	30,282	121
Miscellaneous Common Utilities & Buildings	46,778	48,595	46,579	186
SUBTOTAL-DIRECT COSTS	424,130	447,628	411,724	1,647
Site Acquisition and Development	65,391	70,256		
Construction Management, Startup, Operator Training, Warehouse Inventory	54,516	56,666		
Project Development and Management, Permitting, and Preliminary Engineering	59,482	64,185		
Miscellaneous Off-Site Cost: --Big Bend Coal Truck Loading Facility	3,397	3,516		
TOTAL PROJECT COST	606,916	642,251		
DOE COST SHARE	-122,659			
TOTAL COST TO TAMPA ELECTRIC (Excluding Interest During Construction)	484,257			

Table 4-1 Polk Unit 1 IGCC Capital Cost

The first column of the table shows Polk's actual cost. Figure 4-1 shows the specific years those costs were incurred as a fraction of the total cost. In interpreting the cash flow and some of the indirect costs, it is important to note that cost accrual

began prior to the project's DOE Clean Coal Technology Award in January 1990. Costs continued to accrue as the project changed sites and technologies. Consequently, the fraction of project costs incurred prior to 1994 is larger than it would be for a normal commercial project. Site development work finally began in early 1994. First commercial operation occurred in September 1996. The relatively higher fraction of overall costs incurred in 1996 reflects startup activities.

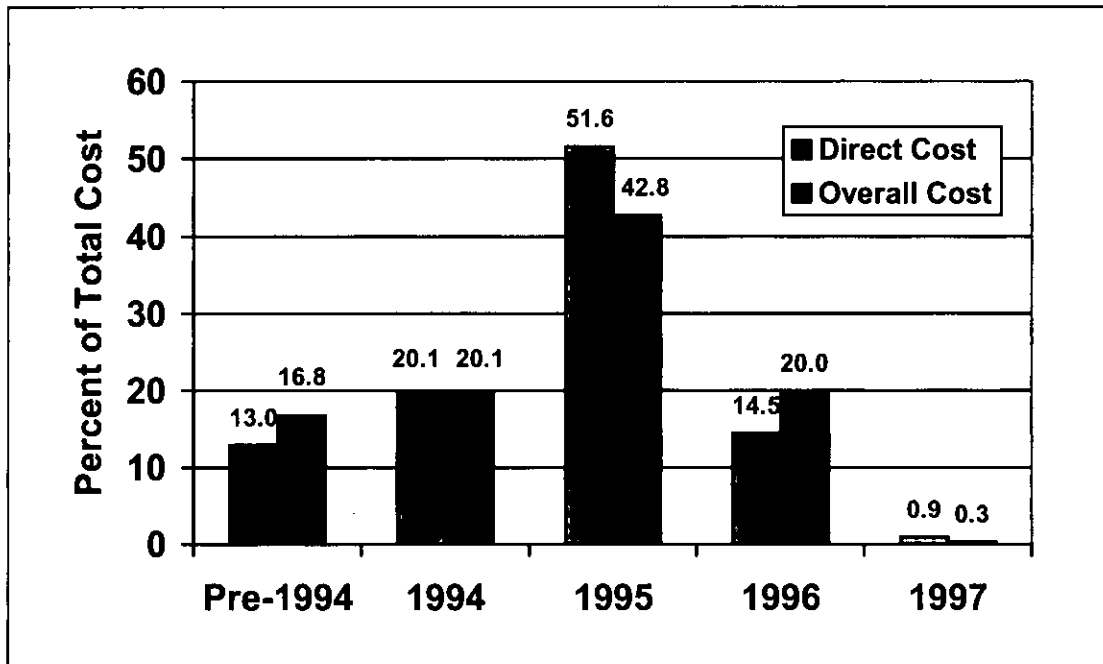


Figure 4-1 Cash Flow

The second column of Table 4-1 shows the column 1 costs escalated from the year they were expended to mid-year 2001 based on escalation factors from the Chemical Engineering Plant Cost Index. Consequently, the second column of Table 4-1 reflects the cost of the plant as if it were "instantaneously conceived, permitted, and erected" in 2001.

The third column of Table 4-1 is more important. It reflects our best estimate of the cost of replicating the Polk design in a new plant at the Polk site which incorporates all the lessons learned and changes made at Polk. It is on the same "instantaneously erected" basis as the second column. The fourth column expresses the costs from column 3 in \$/kW based on Polk's 250 MW net output.

The adjusted costs at \$1650/kW (mid-2001 dollars) are higher than we had hoped, but they are not surprising given Polk's site specific factors, most of which tend to increase the facility costs. For example, the relative scarcity of water in Florida dictates that diluent nitrogen be used as the primary means of NO_x suppression rather than the more efficient and very much less expensive syngas saturation approach. The ability to discharge even a relatively small amount of process

wastewater would obviate the need for the expensive brine concentration system. And Florida's high ambient temperature and relative humidity lead to higher cooling water temperatures and lower steam cycle output than in other parts of the country for the same capital investment, further lowering the plant's efficiency and increasing the net cost per kW. Also, Polk is a single-train unit with no economies of scale. Even using Polk's gasifier and combustion turbine size, significant economies of scale can accrue in virtually all other areas of the plant which account for well over 60% of the total direct costs. Given all the above factors, it is conceivable that costs as low as \$1300/kW could be projected in an ideal situation.

Capital Cost Adjustments

Over 90 adjustments were made to the original project scope and capital cost to estimate the cost of replicating the Polk design in a new plant incorporating all the lessons learned. These adjustments account for the difference between the second and third columns of Table 4-1. They totaled \$35.9 million or \$144/kW.

Note that only adjustments to the direct plant costs were attempted. In most cases, there will be significant savings in the indirect costs as well, but the issues vary too widely between sites and projects to make credible estimates. Consequently, only direct costs were considered. Even at that, there are many site-specific conditions as previously mentioned which dictate some aspects of the plant configuration and performance and these have a significant cost impact.

The following are the most important changes from Polk Unit 1 to this "next generation" plant in order of their financial impact.

\$25-\$30 Million

Eliminate Hot Gas Cleanup

Polk's hot gas cleanup system has never operated (Section 1.3.6.6.1) so it would not be included in a new plant based on Polk experience. Not only do significant savings accrue directly from eliminating the HGCU system, but additional savings in excess of \$2 million are realized by economies of scale with only one convective syngas cooler and syngas scrubber train instead of two.

\$10-\$15 Million

Reduce Scope of High Temperature Gas Cooling

The raw gas / clean gas exchangers were eliminated early in the project (Section 1.3.4.4.1) and most of the sootblowing system was more recently removed (Section 1.3.4.4.4). With these gone, the troublesome SGC MP steam system can also be eliminated (Section 1.3.4.4.8). In turn, these lead to significant cost reductions in the main gasifier structure. Together, the savings will be in the \$10 million to \$15 million range.

\$5-\$10 Million

Lower Direct Engineering Costs

By replicating the Polk design and reducing the engineering requirements in the difficult high temperature gas cooling area, direct engineering cost reductions of \$5 million to \$10 million, or even more, should easily accrue.

\$2 to \$5 Million

Add COS Hydrolysis

A COS hydrolysis system (Section 1.3.6.4.1) and the associated MDEA reclaim system (Section 1.3.6.4.2) will cost \$3 million to \$4 million.

\$750,000 to \$2 Million

Shorten Interconnecting Piping, Pipe Racks

Polk Unit 1 is spread out, resulting in higher than usual interconnecting piping costs. The pipe rack route from the ASU to the gasification structure is 600 ft, from the gasification structure to the power plant is 700 ft, and the ASU to the power plant is 900 ft. Locating the main subsystems closer together and more directly routing the piperacks would result in interconnecting piping cost reductions of \$2 million or more.

Add Slag Handling and Fines Separation Equipment

Polk's original slag handling system had several drawbacks. It was manpower intensive, it did not provide for separation of fines for recycle, and it did not eliminate chloride and ammonia laden grey water from coarse lockhopper slag which would have otherwise been marketable (Section 1.3.5.6.1). Also the fines handling system was pitifully undersized for the much higher than design fines production. The cost to remedy these deficiencies in a new plant would approach \$2 million.

Add Syngas Saturator

More diluent is needed than is available at Polk to meet Polk's future NO_x emission limits (Section 1.4.2.6.1). A syngas saturator is a good way of providing this supplemental diluent while efficiently recovering the low level waste heat that became available when the raw gas / clean gas exchangers were removed. Saturator system costs would approach \$1.5 Million.

Delete Water Wash Column

Polk's original design incorporated a water wash column to remove contaminants from the syngas which would form heat stable salts in the MDEA acid gas removal solvent. Extensive testing has shown that the water wash column is almost completely ineffective at removing these contaminants, and, in any case, an ion exchange system to regenerate the heat stable salts is very much less expensive than the water wash system which cost almost \$1 million.

\$250,000 to \$750,000

Increase Main Air Compressor Capacity

A modest increase in the air separation plant's main air compressor capacity costing less than \$500,000 in a new plant would provide sufficient oxygen year around to fully load the combustion turbine and recycle sufficient fines so the net slag produced would be marketable (Section 1.2.7.1)

Upgrade Slurry Materials

Materials and coatings in the slurry preparation system (Section 1.3.3.4.1) costing less than \$500,000 in a new plant would significantly reduce failures.

Delete Fines Filter

Off-site disposal of the fines produced by the gasifier is prohibitively expensive for Polk, and encumbering landfills with tons of material containing significant heating value is not appropriate. Recycling the fines as concentrated slurry from the settler bottoms to the slurry preparation system is Polk's current practice. This is a better alternative than producing a filter cake for disposal using the fines filters which cost almost \$500,000.

Modify Syngas Scrubber Design

Polk's syngas scrubbers have a persistent problem with water entrainment when operating at design conditions which has created some safety issues (Section 1.5.7.5.1) and other problems downstream (Section 1.3.6.5.1) Modifications to eliminate this problem could require substantially increasing the size of the vessel which would cost up to \$400,000.

Separate MDEA Acid Gas From Ammonia Gas

Line pluggage occurs wherever ammonia gas combines with acid gas (Section 1.5.7.5.2). Completely separating these systems in a new plant will cost up to \$400,000.

Rust-Resistant Coatings for Main Air Compressor Components

Most air separation plants operate continuously, but in an IGCC plant they are likely to start and stop more frequently. This promotes the formation and exfoliation of rust particles from the carbon steel piping and other main air compressor components. The rust particles plug the fins of intercoolers and aftercoolers, destroying their effectiveness and increasing pressure drop (Section 1.2.7.1). Coatings costing up to \$300,000 can eliminate this problem.

Other Accounted Changes and Net Change

On balance, the items detailed above account for almost a \$40 million cost reduction from the Polk cost in mid 2001 dollars. All the other changes individually cost relatively little by comparison to those identified above. Some of these other adjustments were additions and some deletions, but their net effect was to add approximately \$4 million to the cost, which resulted in the overall net reduction of \$35.9 million in the direct plant costs shown in Table 4-1.

4.2 Operating Costs

4.2.1 Operating Fuel

The highest annual cost element is, of course, fuel, and the vast majority consists of coal/petroleum coke for the gasifier. On a normalized basis, the expected annual gasifier fuel consumption would be:

$$\begin{aligned} & 2430 \text{ mmBTU/Hr (Section 6, Figure 6-1)} \\ & \times 8760 \text{ Hr / Yr} \\ & \times 0.80 \text{ Gasifier On-Stream Factor} \\ & \times \underline{0.95 \text{ Gasifier Output Factor}} \\ & = 16.2 \text{ million MMBTU / Year} \end{aligned}$$

The only other fuel consumed during normal operation is 40 gallons / day of propane for the flare pilot lights. Since the flare is almost always lit, this would amount to:

$$\begin{aligned} & 40 \text{ gal / day} \\ & \times 91,000 \text{ BTU/gal} \\ & \times \underline{360 \text{ days / year}} \\ & = 1300 \text{ MMBTU / Year} \end{aligned}$$

The combined cycle may be dispatched on distillate fuel when the gasifier is unavailable. This will depend entirely on the system demand, so this is not included here.

4.2.2 Startup Fuel

Additional propane and distillate fuel is consumed during gasifier startup and after gasifier shutdown.

The combustion turbine's startup and back-up fuel is low sulfur distillate. Minimum consumption would provide low load CT operation for one or two hours during gasifier lightoff and line out, and another one or two hours after gasifier shutdown. It would also typically be kept running during brief outages prior to gasifier hot restarts. The CT would consume about 50,000 lb of distillate per hour of low load operation or about 925 MMBTU/Hr. Of course, some power is generated to help offset these distillate fuel costs during this time, and the load may be increased to improve its efficiency during these periods.

The auxiliary boiler is also used to generate steam for regeneration of the ASU air dryers for its extended operation while it cools down before gasifier lightoff and for its operation to provide purge nitrogen for several hours following gasifier shutdown. An average of 87,500 lb of distillate fuel (1600 MMBTU) is consumed by the auxiliary boiler during each gasifier cold startup and shutdown for an extended period.

Propane is used to heat the gasifier and sulfuric acid plant during cold startups, and a small amount is used to maintain sulfuric acid plant catalyst bed and decomposition furnace heat during brief outages prior to hot restarts. Normally, 2000 gallons of propane (180 MMBTU) is consumed during a hot restart, and 16,000 gallons (1450 MMBTU) during a cold startup.

4.2.3 Plant Staff

Figure 4-2 is the station organization chart showing the permanent plant staff. The five operating and maintenance teams are its foundation. Each team nominally consists of 10 multi-skilled process specialists who operate the unit and perform and supervise the maintenance work. Supporting the teams are a six-person engineering staff, 9 specialists, a three person laboratory staff, and 10 administrative and management personnel.

4.2.4 Other Operating Costs

In addition to fuel and the salaries and fringe benefits for the permanent staff, the plant has historically incurred annual costs shown on Table 4-2:

ITEM	Annual Cost (\$ Million)
Catalysts and Chemicals: Water Treatment, Flocculent, Acid Gas Removal, COS & SAP Catalyst	1.0
O&M – General Maintenance and ASU: Building, Structure, and Site Maintenance; Safety and General Supplies; Waste Disposal (except slag)	1.5
O&M – Gasification: Coal and Slurry, High Temperature Gas Cooling, Slag and Fines Handling, Gas Cleaning, Sulfuric Acid Plant	4.5
O&M – Power Block, Common and Plant Water Systems	2.0
Sustaining Capital – Small Projects: Replacement of Worn Capital Equipment and Minor Improvements	2.0

Table 4-2 Annual Operating Costs

Slag handling and disposal costs are not included in the above table. The costs for plant modifications, the incremental fuel costs, and extra handling and waste disposal costs associated with the slag problem have totaled well over ten million dollars to date. These have been extremely burdensome, but we anticipate eliminating all or most of them with some capital improvements within the next 2 years. See Sections 1.3.5.6.1 for details on this issue.

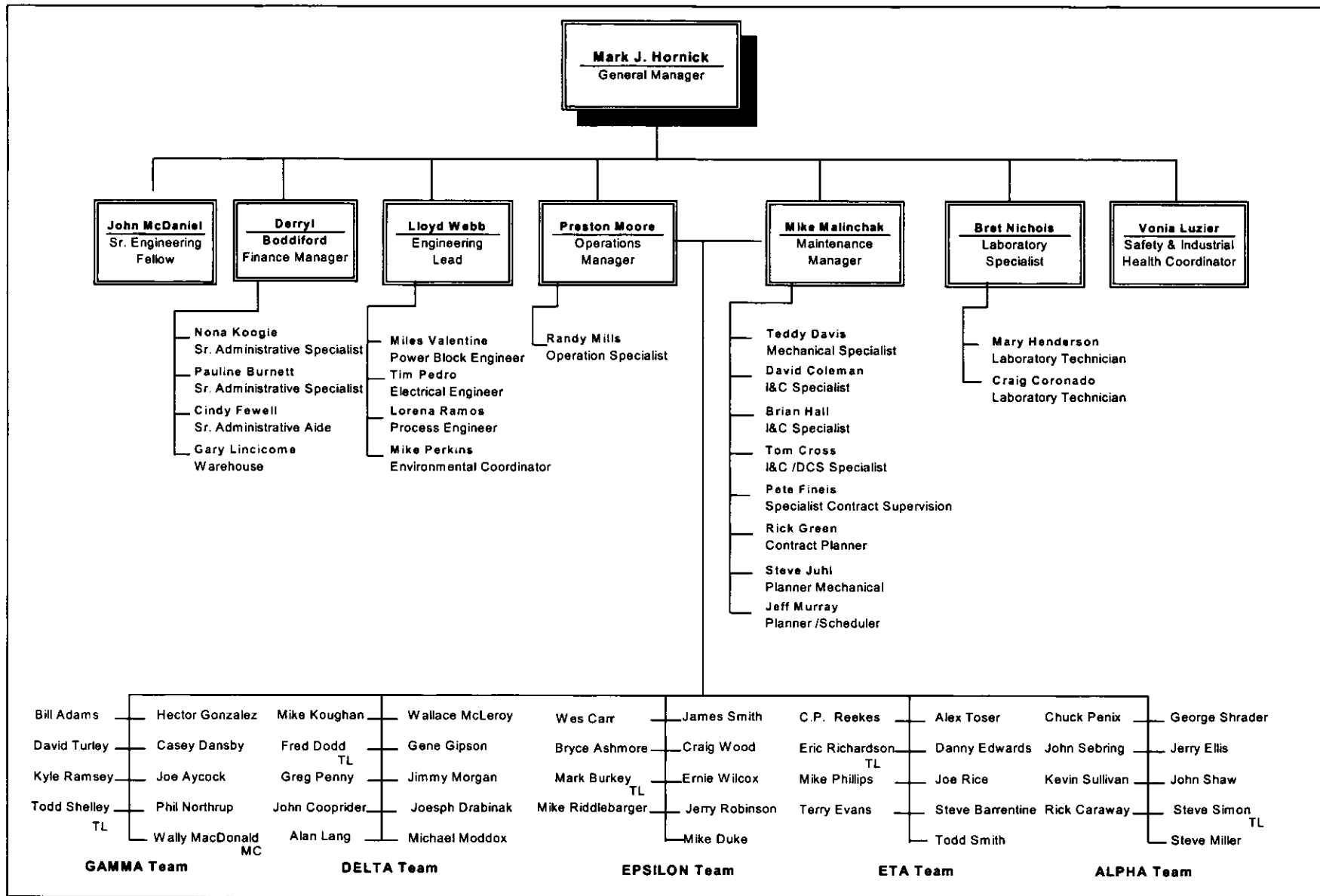


Figure 4-2 Polk Power Station Organization Chart

CHAPTER 5 - FUELS AND TEST BURNS

5.1 Fuel Quantities and Composition

Eleven U.S. Coals were gasified individually at Polk Power Station during the 5 year demonstration period. Six other fuels were gasified in combination with one another or in various blends with one of the eleven individual coals.

There were several reasons for so many fuels and fuel blends. Chief among them was to identify the fuel or blend which resulted in the lowest cost of electricity to the Tampa Electric ratepayers. Evaluating a potential fuel involves quantifying the impact of its characteristics on the processing cost. The cost impact of some fuel characteristics such as its sulfur and chlorine content are relatively easy to determine. Other characteristics such as carbon conversion and gasifier refractory liner life can be estimated from a chemical analysis but can only really be determined by full scale operation in the plant.

There were other reasons for changing coals. Two satisfactory coals became unavailable due to mine closure. Some coals or blends simply bridged a gap created by temporary inventory shortfalls. Also, the DOE Cooperative Agreement included a requirement to test four coals. Regardless of the reason each fuel or blend was processed, every one provided new insights to the IGCC process and helped demonstrate its fuel flexibility.

The fuels gasified and tonnage of each are identified in Table 5-1. Table 5-2 shows when each fuel was processed, and their analyses are in Table 5-3.

Seam	Mine	Supplier	Tons Gasified
Individual Coals			
Pittsburgh #8	Humphrey	Consolidation Coal Company	85,743
Pittsburgh #8	Williams #4	Bell Mining Company, Inc.	19,800
Pittsburgh #8	Loveridge	Consolidation Coal Company	125,256
Pittsburgh #8	Cumberland	RAG Cumberland Resources, LP	170,058
Pittsburgh #8	Blacksville	Consolidation Coal Company	349,805
Illinois #6	Old Ben No 11 mines	AEI Resources, Inc.	63,467
Illinois #6	Wildcat	Sugar Camp Coal , LLC	10,620
West Kentucky #11	Ohio No 11	Consol/Island Creek Coal Co.	563,436
Kentucky #9	Camp	Peabody CoalSales , Inc.	589,835
Kentucky #9	Patriot	Peabody CoalSales, Inc.	250,065
Indiana #5 & #6	Somerville	Black Beauty Coal Company	97,611
Blended Fuels			
Petroleum Coke	Chalmette	Oxbow Carbon/PCMC Petcoke	133,173
Indonesia	Paringin/Tutpan	P.T. Adaro Indonesia	72,433
Guasare Basin	Mina Norte	Peabody CoalTrade, Inc.	55,433
Pittsburgh #8	Powhatan #6	American Coal Company	30,593
Powder River Basin	Jacobs Ranch	Kerr McGee Coal Corporation	1,631
Biomass (Eucalyptus)	N/A	Common Purpose, Inc.	9

Table 5-1 Polk Fuels: Tonnage

Fuel: Mine/Supplier	1996	1997	1998	1999	2000	2001
Humphrey / Consol	46	144				
Williams No 4 / Bell		9				
Loveridge / Consol			26			
Cumberland / RAG					58	28
Blacksville / Consol					35	
Blacksville-Cumberland Blend					16	
Powhatan #6 + 40% Mina Norte						20
Old Ben No 11 mines / AEI Resources, Inc.		20	7			
Wildcat / Sugar Creek			6			
Camp / Peabody				65	164	
Camp + 20% Ky 11				5		
Patriot / Peabody						100
Somerville No 7 / Black Beauty						28
Ohio 11 (Kentucky 11) / Consol		5	191	51		
Ohio 11 Blended with:						
20% PRB			1	3		
25% Indonesian				44		
20% Indonesian				87		
Petroleum Coke Blended with:						
60% Black Beauty		6				
Various Mina Norte + Black Beauty						62
1% Biomass + Mina Norte + Black Beauty						1
60% Blacksville					10	
40% Blacksville					10	

Table 5-2 Polk Fuels – Days of Operation

Seam/Mine	Analysis – Dry Basis							Analysis - As Received Basis					Ash T ₂₅₀
	C	H	N	S	O	Ash	Cl	HHV	Moisture	VM	FC	Ash	
Pittsburgh #8													
Humphrey	76.52	4.90	1.58	1.87	5.91	9.14	0.08	13060	5.87	35.41	50.12	8.60	2645
Williams No 4	75.18	4.85	1.34	3.00	5.97	9.62	0.04	13201	3.82	38.06	48.87	9.25	2205
Loveridge	77.82	5.15	1.51	1.90	5.88	7.63	0.11	13670	2.11	37.10	53.32	7.47	2485
Cumberland	77.97	5.17	1.50	2.79	4.01	8.49	0.07	12696	8.79	35.12	48.35	7.74	2372
Blacksville	81.14	4.83	1.42	1.93	3.50	7.10	0.08	13667	4.03	30.38	58.78	6.81	2461
Powhatan #6	74.72	5.20	1.37	3.90	5.73	9.00	0.08	12634	6.18	38.18	47.20	8.44	2238
Illinois #6													
Old Ben No. 11	70.27	4.84	1.36	3.72	9.10	10.60	0.11	10934	13.70	34.62	42.53	9.15	2480
Wildcat	74.48	4.78	1.55	2.73	6.83	9.46	0.17	12597	5.99	33.92	51.20	8.89	2420
Kentucky #11													
Ohio No 11	73.54	5.05	1.56	3.20	9.66	6.88	0.11	11963	11.30	36.70	45.90	6.10	2265
Kentucky #9													
Camp	72.20	5.04	1.60	3.30	7.35	10.40	0.11	11510	11.00	34.99	44.75	9.26	2415
Patriot	72.39	5.01	1.59	3.01	7.77	10.18	0.05	11133	13.20	35.97	41.99	8.84	2391
Indiana #5 & #6													
Black Beauty	73.08	5.12	1.51	3.80	6.87	9.58	0.04	11317	12.90	37.06	41.70	8.34	2279
Miscellaneous													
Paringin Indonesian	72.64	4.97	0.86	0.13	20.20	1.21	0.02	9363	25.90	36.43	36.77	0.90	2235
Jacobs Ranch Powder River Basin	69.69	5.03	0.96	0.29	18.30	5.71	0.05	8847	26.70	33.21	35.90	4.19	2212
Petroleum Coke: Chalmette Refinery	88.67	3.27	2.24	4.61	0.63	0.54	0.04	13743	10.00	10.69	78.82	0.49	N/A
Mina Norte Guasare Basin	73.67	5.20	1.37	0.76	8.84	9.98	0.03	11665	11.15	32.79	47.20	8.87	2820

Table 5-3 Polk Fuels – Composition

5.2 Test Results

5.2.1 Sulfur Removal and Recovery

The sulfur removal system demonstrated the capability to meet the permitted SO₂ emission level of 357 lb/hr year around while processing fuels with a sulfur content up to about 3.5 % (wt-dry basis) or about 5.0 lb SO₂/MMBTU. Both the Old Ben and Black Beauty coals contain slightly more sulfur than this, but they were processed without difficulty during the winter months when the MDEA acid gas removal solvent is cooler and more effective.

5.2.2 Brine Concentration System

Brine concentration must remove all the coal's chlorine while maintaining the grey water chloride concentration at or below 3500 ppm (wt) to prevent corrosion. The brine unit can process about 100 gpm of grey water which removes 175 lb/hr Cl. This limits the fuel's Cl content to about 0.075 lb Cl/MMBTU at full load (250 MW net) at the normal coal-fired heat rate of 9500 BTU/kWH. The average coal HHV was 13,400 BTU/Lb, so the coal's Cl content is typically limited to 0.10% (wt-dry basis). The brine concentration unit was severely taxed when the plant was utilizing Loveridge, Old Ben No. 11, and Ohio 11 coals which contain 0.11% Cl. Wildcat coal with 0.17% Cl exceeded the Cl capacity as evidenced by the fact that the process water (grey water) turned very rusty red soon after the Wildcat was introduced. The Cl concentration in the process water at this point was between 4500 and 5500 ppm. A larger brine concentration system would be required to process many U.S. coals, particularly those in the Illinois Basin which typically contain 0.2 % (wt dry basis) Cl or more. The current base feedstock is a blend containing 55% (wt) petroleum coke, and since petroleum coke has very little chloride, the brine concentration system capacity is not now a significant issue.

5.2.3 Slurry Preparation System

Fuels express their individuality in the slurry preparation system as much as anywhere in the plant. Although we can estimate the characteristics of slurries produced from various fuels, most fuels present some surprises so full scale operation and experience is needed to really determine how to best prepare slurry from each.

Polk has a very limited oxygen supply. Consequently, a high slurry concentration is essential to produce enough syngas for base load operation (250 MW net). Some fuels require an additive to lower the apparent viscosity of the slurry at high concentrations so it will flow through the screens and the pump suction piping. Others require an additive to prevent the solid fuel particles from settling in the agitated tanks and lines. Slurries made from some fuels also require pH adjustment to minimize erosion/corrosion. Polk has used both a 50% caustic solution and anhydrous ammonia to control pH. Caustic is preferred. Table 5-4 indicates which fuels received pH adjustment and a viscosity reducing or stabilizing additive. The additive dose rates were not optimized on all fuels.

Mine/Supplier	PH Control	Viscosity/Stability Additive
Humphrey / Consol	No	No
Williams #4 / Bell Mining	No	No
Loveridge / Consol	No	No
Cumberland / RAG	Yes	Yes
Blacksville / Consol	Yes	Yes
Blacksville/Cumberland Blend	Yes	Yes
Powhatan #6 + 40% Mina Norte	No	No
Old Ben No 11 / AEI Resources	Sometimes	No
Wildcat / Sugar Camp	No	Yes
Camp / Peabody	Sometimes	Yes
80% Camp + 20% Ky 11	No	No
Patriot / Peabody	Yes	Yes
Somerville / Black Beauty	Yes	Yes
Ohio 11 / Consol, Island Creek	Sometimes	Sometimes
Ohio 11 Blended with:		
20% PRB	Yes	Sometimes
25% Indonesian	Yes	Yes
20% Indonesian	No	No
Petroleum Coke Blended with:		
60% Black Beauty	No	No
Various Mina Norte + Black Beauty	Yes	Sometimes
1% Biomass + Mina Norte + Black Beauty	Yes	Yes
60% Blacksville	Yes	Yes
40% Blacksville	Yes	Yes

Table 5-4 Slurry Additives

5.2.4 Carbon Conversion and Gasifier Refractory Liner Life

High carbon conversion is important for efficiency and to minimize or eliminate the amount of flyash for disposal which is very expensive. High conversion at high slurry concentration and low operating temperature is ideal since this extends the gasifier refractory liner life and minimizes the amount of oxygen needed. Minimizing oxygen consumption is particularly important at Polk since the oxygen supply is limiting. Flyash containing unconverted carbon can be recycled to the gasifier to eliminate the disposal cost, but this increases the oxygen requirement since it degrades the quality of the slurry fed to the gasifier. With 100% coal fuel, recycling flyash appears to have only a slight positive impact on overall efficiency (net heat rate) since the energy recovered from the recycled flyash is offset to a large extent by the incremental auxiliary power to produce the additional oxygen. With pet coke in the fuel blend, the positive impact of recycle on overall efficiency is greater since the recycled material is higher quality and there is more of it.

Carbon conversion and refractory liner life for a specific slurry can be estimated as a function of gasifier operating temperature. However, a full scale test is needed to

determine these important parameters at sufficient accuracy to develop the most cost-effective plant design. The Polk gasifier is the largest Texaco gasifier which had been built at that time, so it was not possible to conduct such a test before designing the plant. Had we been able to do this, the facility would not be subjected to the current oppressive flyash disposal costs and oxygen limitations which lead to load restrictions.

At Polk, we determine these parameters for the fuels we process through an extensive sampling, analytical, and data reduction effort. Once steady state plant operation is achieved, multiple samples of each important stream are gathered and analyzed over 4 to 12 hours which we refer to as a "heat and material balance period". The analytical results are then combined with other operating data (flows, temperatures, and pressures) using a non-linear regression technique to determine the "most likely" values of the key variables subject to known heat and material balance constraints. Each such effort results in one data point. 62 of these heat and material balances have been conducted to date.

Several data points are required to develop each fuel's "characteristic". This characteristic is best presented as a graph of carbon conversion versus indicated refractory liner life on which each point represents a different gasifier operating temperature or O/C ratio (oxygen to carbon atomic ratio). The characteristic curve for each fuel may shift with changes in any one of several independent variables, the most important of which are throughput, burner configuration, refractory liner quality or condition, slurry concentration, and fraction of flyash recycled. The characteristic curves are then used in an economic model to optimize plant operation, compare performance of different burner designs or refractory liners, compare fuels, or simply alert us to an unidentified change in some fuel property such as ash composition. Although there is some data scatter, the characteristic curves all show the expected trend of low operating temperatures associated with low carbon conversion and long liner life, and vice-versa. Some of the characteristic curves generated from the 62 heat and material balances will be presented and compared in the following discussions.

Humphrey Pittsburgh #8 and Refractory Liner Quality

The initial gasifier refractory liner was a low cost /low quality liner to avoid wasting an expensive liner because of startup upsets (Section 1.4.4.4.3). Humphrey Pittsburgh #8 was the closest fuel to the plant's design fuel that we could procure, so it was used as the startup fuel even though it was relatively expensive. Its characteristic curve on the standard high quality liner is compared to the data points generated while the startup liner was in service in Figure 5-1. The design and expected operating points are also shown. The inferior performance (short life) of the startup liner is obvious. It is equally obvious that this fuel's performance on the higher quality commercial liner was significantly below expected performance, and somewhat below design performance.

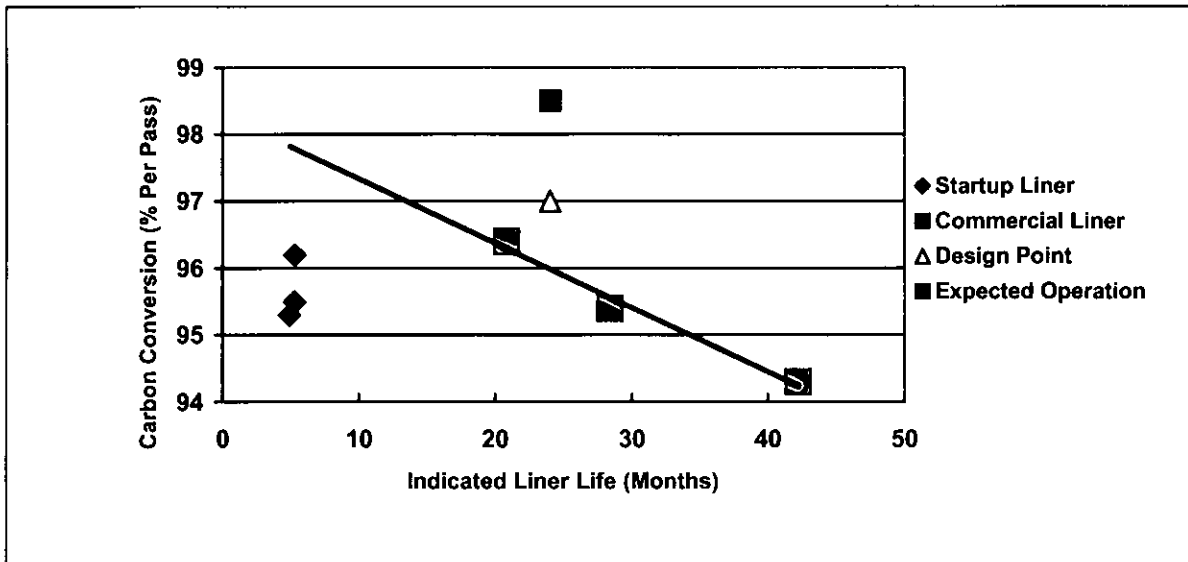


Figure 5-1 Startup Liner
Humphrey Pittsburgh #8

Burner Design

Recognizing the performance problem, Texaco cooperated with us in making several minor burner design modifications which did not have any statistically significant effect. In early 1999, we did test two radically different burner configurations while processing a blend of Kentucky 11 and Indonesian coals. Although there was more scatter than normal in the results shown in Figure 5-2, they do indicate that the standard burner design was superior to the two test designs.

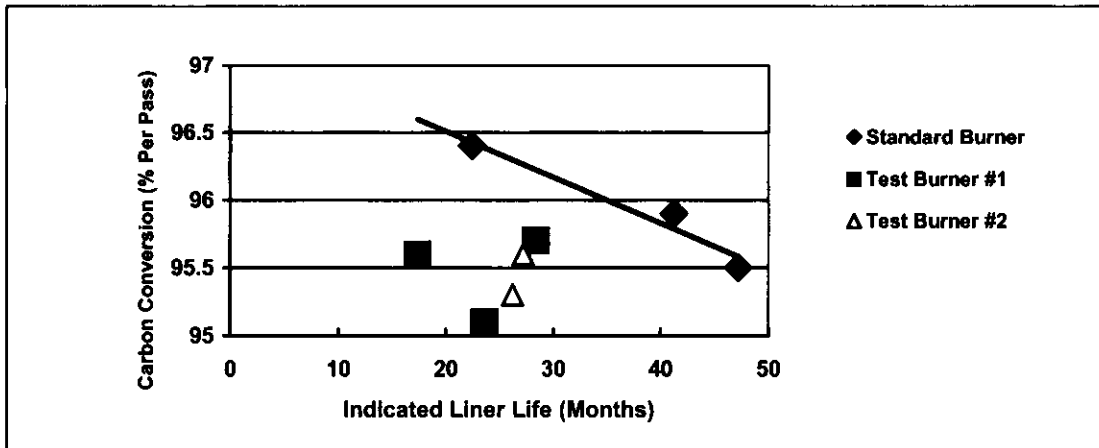


Figure 5-2 Test Burners #1 and #2

Kentucky #11 + Indonesian Coals.

In mid-2001, a third test burner was installed during operation on a blend of 40% to 50% petroleum coke with Black Beauty and Guesare Basin Mina Norte coals. This burner shows promise, but the results are mixed. 2 of the 4 data points show significant improvement over the standard burner, and the other 2 appear to be on the standard burner's characteristic curve as shown in Figure 5-3. More data is needed.

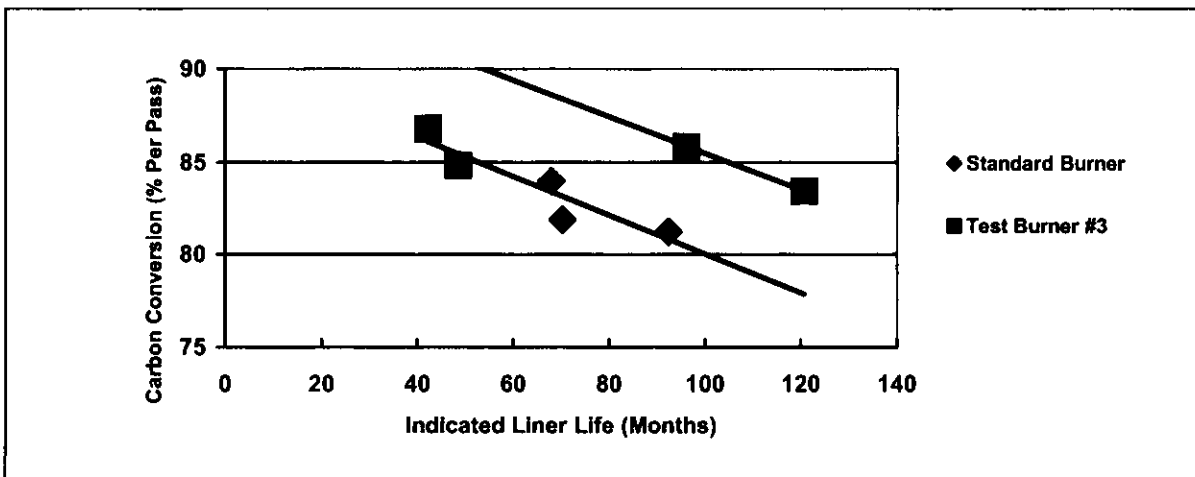


Figure 5-3 Test Burner #3

40%-50% Pet Coke with Mina Norte + Black Beauty

Effect of Recycling Flyash

Recycling flyash increases overall carbon conversion and oxygen consumption in all cases. For Kentucky 11 coal, recycle causes a significant drop in per-pass carbon conversion (Figure 5-4) which further increases the oxygen requirement. For the 40% to 55% petroleum coke blend with Black Beauty and Guasare Basin Mina Norte coals, the opposite is true; per-pass conversion improves with recycle (Figure 5-5) which partially mitigates the additional oxygen requirement. It would be convenient if a single parameter could explain the differences in the effects of recycle on the two fuels. Unfortunately it seems there are several competing factors at work such as changes in O/C ratio, slag traffic, and reactivity of the recycled material compared to that of the base fuel. It is likely that the relative importance of these factors changes between fuels in a way we don't understand at the present time. This is one reason a test is important in establishing a new plant design.

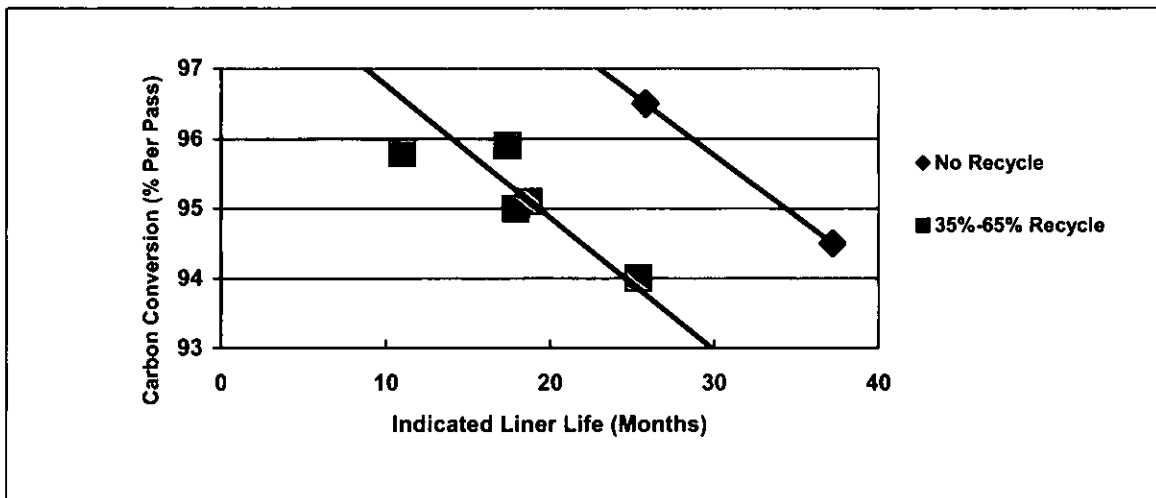


Figure 5-4 Effect of Recycle with Kentucky 11 Coal

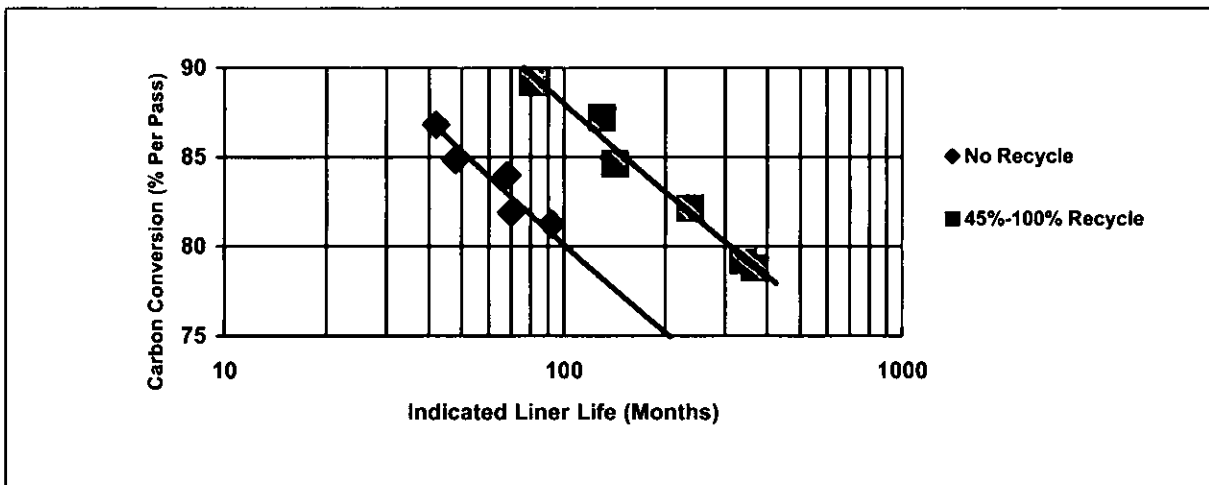


Figure 5-5 Effect of Recycle with Petroleum Coke Blend Fuel

Pittsburgh #8 Coals

Five coals from the Pittsburgh #8 seam were processed. Results are shown on Figure 5-6. Only the Humphrey data on this figure was generated without recycle. Between 30% and 75% of the settler bottoms flyash was returned to slurry preparation during data gathering for all the other coals.

The coals seem to be separated into two classes, but this is probably a mere coincidence. Humphrey (the startup coal) and Loveridge both performed reasonably well, within about 1% of design conversion at a two year liner life. For Bell, Blacksville, and Cumberland, conversion was almost 4% lower at conditions that would result in the same 2 year liner life.

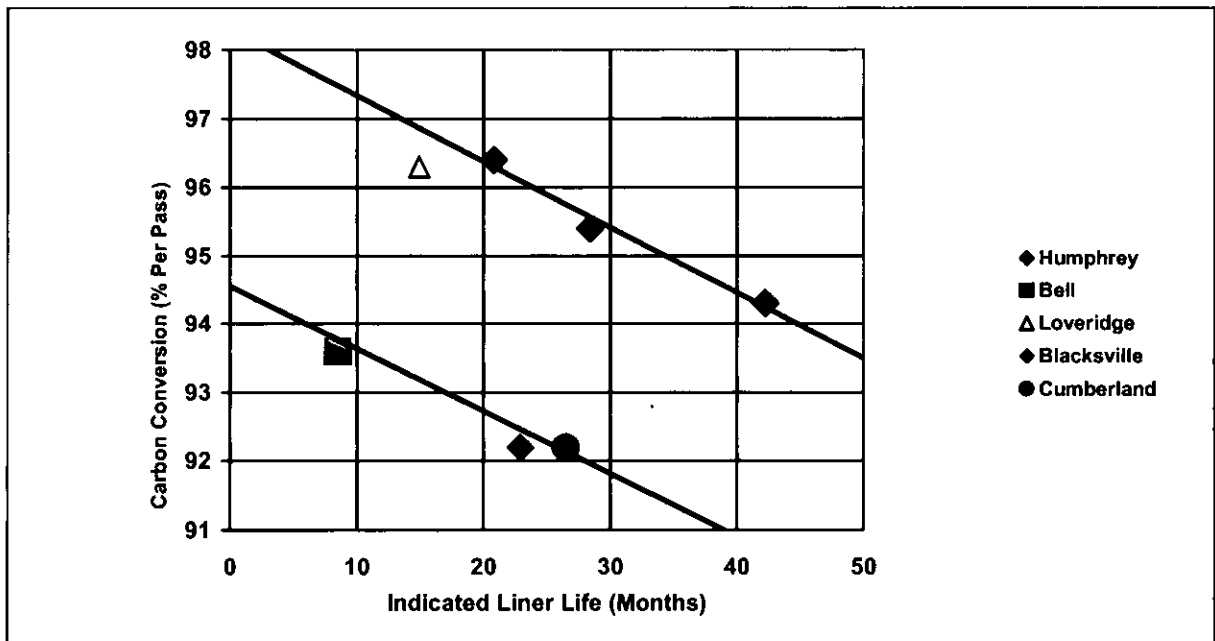


Figure 5-6 Pittsburgh #8 Coals

Illinois Basin Coals

Performance of the Illinois Basin coals is shown in Figure 5-7. All data presented here reflects performance with at least 30% recycle, but the relative performance without recycle is similar. All data points shown were generated with the standard burner except the Patriot data point which was with Test Burner #3. This may have contributed to its indicated superior performance. Performance of the Old Ben No. 11 was also excellent, but, as mentioned earlier, additional investment in the brine concentration system would be required to use it at Polk because of its high chloride content. Wildcat, Black Beauty, and Camp all appear to be capable of per-pass conversion of 95½% to 96% with a two year liner life. The Kentucky 11 conversion is about 1% lower for the same liner life.

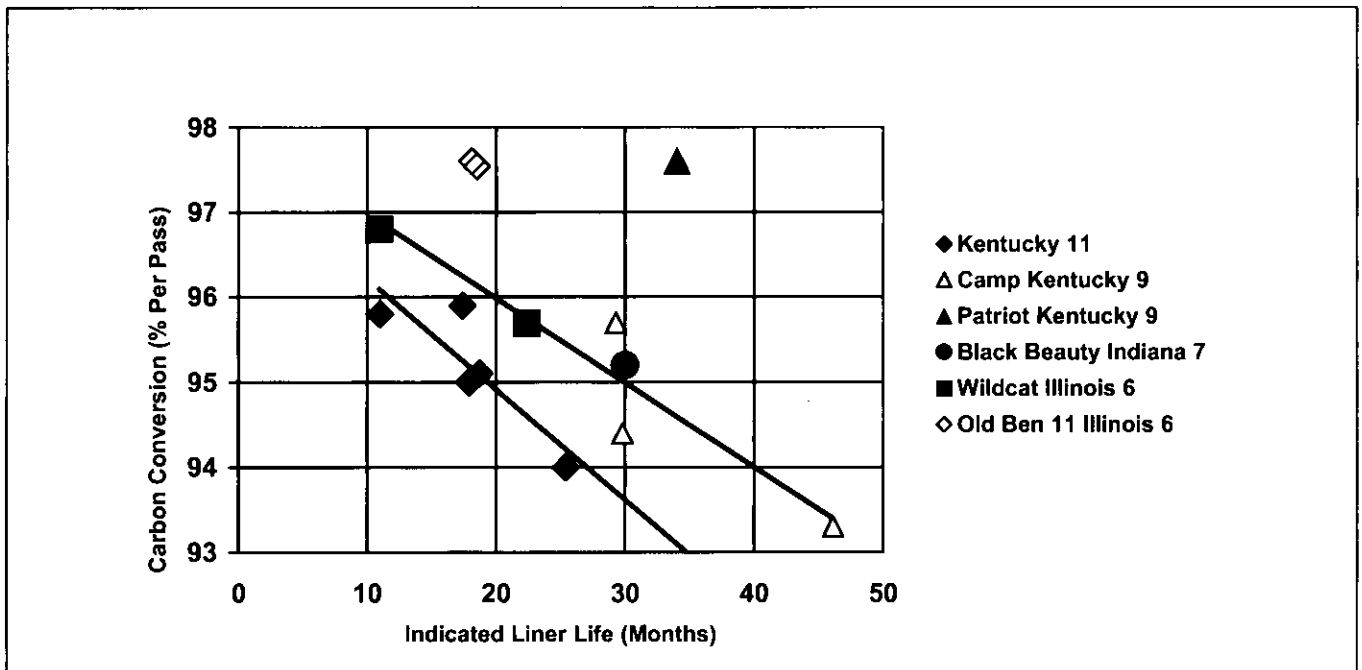


Figure 5-7 Illinois Basin Coals

Petroleum Coke Blends

Petroleum coke is a relatively inexpensive feedstock per unit of heating value compared to coal at the present time. In our efforts to lower the cost of electricity, it was natural to try blends of this fuel. Petroleum coke typically has more sulfur than the Polk sulfur removal and recovery systems can accommodate (5.0 lb/MMBTU), so it is necessary to blend the petroleum coke with lower sulfur coals. The coal ash also serves as a flux for the vanadium in the petroleum coke which has a very high melting point and would otherwise form deposits under gasification conditions. Figure 5-8 shows the key characteristics of the petroleum coke blends tested to date. All data points shown in the figure were generated with at least 30% recycle flyash using the standard burner.

The first petroleum coke blends tested at Polk utilized specially selected shipments of Blacksville Pittsburgh #8 coal. The first test series consisted of 40% coke and 60% coal with about 30% recycle. Indicated conversion was about 84% for a 2-year liner life. Petroleum coke was known to have lower conversion than coal, so this was pretty much as expected. The next test series consisted of a higher coke concentration, 60%, at a higher recycle ratio, 60%. Operation at the 84% to 86% per pass conversion level on this blend resulted in a significantly longer indicated refractory liner life. It is not clear whether this performance improvement was due to the higher recycle ratio or the higher concentration of petroleum coke in the fuel blend.

In an effort to further improve performance, we began to tailor the ash composition by blending a high ash fusion temperature coal from the Mina Norte mine in South America with Black Beauty Indiana #7 seam coal which has a relatively low fusion temperature. The performance of the final combination we tested exhibits the excellent liner life and acceptable conversion shown in the figure. This is now our base feedstock. Note that the projected liner life in the figure is presented on the more appropriate logarithmic scale. This indicates that liner loss during normal operation will be virtually insignificant, and the actual liner life will be determined almost entirely by that encountered during startup, shutdown, and upset periods which should also be relatively small.

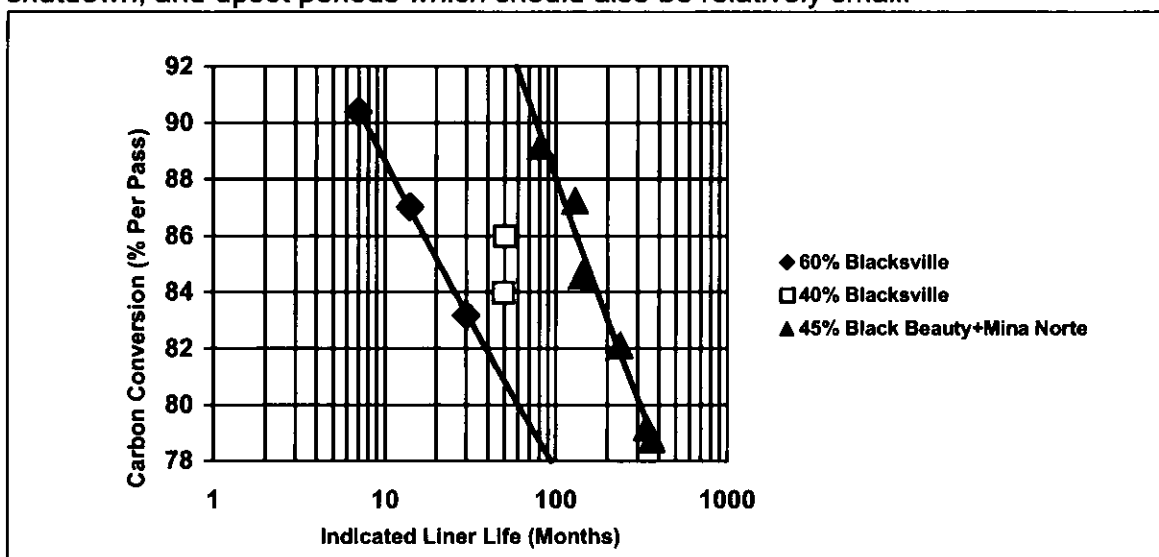


Figure 5-8 Petroleum Coke Blends

CHAPTER 6 - MASS AND ENERGY BALANCE, EFFICIENCY

6.1 Typical Steady State Energy Balance and Efficiency

Figure 6-1 shows the typical energy flows for the three main sections of the plant. The associated mass balance for the process plant is presented in Section 6.3.

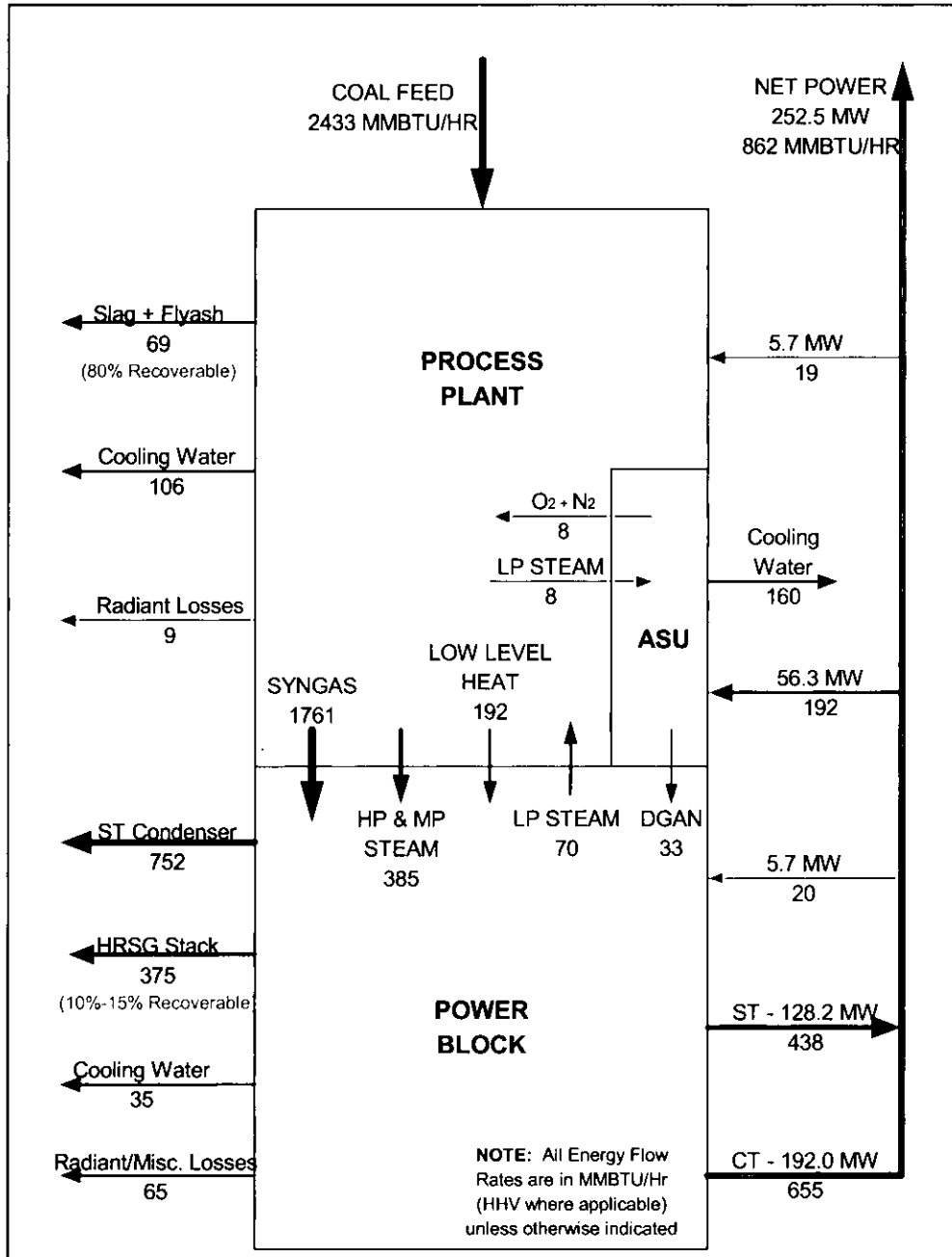


Figure 6-1 Energy Flow

B) Control Processors

All Bailey DCS control modules (40 in all) were originally MFP02's. The nomenclature refers indirectly to the power, speed and price of the controllers, i.e. MFP02's are better than MFP01's and MFP03's are better than MFP02's. When the DCS was quoted, the control system design by engineering was just starting, so the controllers were sized for the estimated amount of control logic plus some spare capacity. By the time the DCS was built and staged at the factory, the control logic from engineering had grown considerably and took nearly all the capacity of the MFP02's. By the end of the factory test prior to DCS shipment to the site, logic corrections and engineering changes and additions increased the loading on some of the MFP02's to the point where they were over-running. Over-running is a condition where the controller cannot finish performing all control logic within the assigned scan frequency.

C) Trends

Bailey Controls configured DCS trends to be their standard trend block which only has 30 minutes data capacity. Approx. 12 man weeks of effort was expended to change all standard trend blocks to enhanced trend blocks. Enhanced trends can hold a user selected number of data points, thus allowing plant operators to view trend data for hours to days depending on the enhanced trend block configuration. This implementation has been so successful that operators always have the trend data they need in the time period they need to see it in.

D) Alarm state conversion

Most alarm contacts in the plant were designed as de-energized to alarm (0). The DCS was originally configured by engineering as energize to alarm (1). Over 1000 alarm states were discovered to be backward from actual field design during checkout. All were corrected on the DCS and are now working properly.

E) Alarm Management

The original configuration on the DCS had just short of 10,000 possible alarms that were possible. Only 1000 alarms at a time can be displayed on a Bailey console. The rest are discarded by the console. Even at 1000 alarms, it is not possible for an operator to pay appropriate attention to alarms that really deserve his/her attention. An alarm priority scheme was developed and implemented. Thousands of alarms were eliminated by moving the default values out of the way for Bailey analog block alarm limits for tags that were not supposed to alarm. The rest require an alarm by alarm review that has continued into 1997 and will probably continue through the end of 1997. The partial result so far is that the operator has far fewer nuisance alarms and can concentrate on the alarms that require their attention.

APPENDIX C - PAPERS AND PUBLICATIONS

DOE CLEAN COAL TECHNOLOGY CONFERENCES

Fifth Annual: Tampa, Florida; January 7-10, 1997

Sixth Annual: Reno, Nevada; May, 1998

Seventh Annual: Knoxville, Kentucky; June, 1999

DOE CLEAN COAL TECHNOLOGY PROJECT REPORTS

Final Public Design Report July, 1996

1996 Annual Technical Report (Covering Startup) July, 1997

GASIFICATION TECHNOLOGIES CONFERENCES

Co-Sponsored by

Electric Power Research Institute (EPRI) and
Gasification Technologies Council (GTC)

San Francisco, California

1996, October 6-9

1997, October 5-8

1998, October 4-7

1999, October 17-20

2000, October 8-11

2001, October 8-10

2002, October 27-30

OTHER CONFERENCE PAPERS

Advanced Clean Coal Technology International Symposium '98
Tokyo, Japan
October 12-13, 1998

AIChE 3rd International Conference In Refinery Processing
Atlanta, Georgia
March 5-9, 2000

ECOS 2000 - Biomass, Coal, and Oil Gasification Session.
University of Twente
Enschede, Netherlands
Polk Power Station IGCC Project - 3½ Years of Operation
July 26, 2000

GlobeEX 2000 Conference and Trade Show
Las Vegas, Nevada
July 23-38, 2000

Note: All papers are included with the CD version of this report.

APPENDIX D - PATENT (COS HYDROLYSIS METHOD)

United States Patent
McDaniel

6,322,763
November 27, 2001

Method and apparatus for removing *carbonyl sulfide* from a gas stream via wet scrubbing

Abstract

Methods for removing *carbonyl sulfide* (COS) from a synthesis gas stream are disclosed. The method entails raising the water level of a wet scrubber so that hydrolysis of the COS may occur in the scrubber itself instead of a COS reduction chamber and no additional catalysts other than those naturally occurring in the production of the synthesis gas need be introduced into the scrubber. The water is raised, in one example, to a level such that water within an inner tube of the wet scrubber flows over an upper end of the inner tube. Raising the water level in the scrubber ensures intimate and vigorous interaction between the water, the COS, and the naturally occurring catalyst, and promotes the hydrolysis of the COS. In one example, the naturally occurring catalyst (e.g., alumina oxide) is present in the coal ash produced when coal is the fuel gasified that creates the synthesis gas stream.

Inventors: **McDaniel; John E.** (Riverview, FL)

Assignee: **Teco, Inc.** (Tampa, FL)

Appl. No.: **460634**

Filed: **December 14, 1999**

Current U.S. Class:

423/242.1; 423/243.01

Intern'l Class:

C10K 001/10

Field of Search:

423/242.1, 243.01, 651, 652 252/373

References Cited [Referenced By]

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0 443 661 A1	Aug., 1991	EP.	

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International Search Report for PCT.US99.29829 Filed Dec. 15, 1999.

Primary Examiner: Griffin; Steven P.

Assistant Examiner: Vanoy; Timothy C

Attorney, Agent or Firm: Wolf, Greenfield & Sacks

Parent Case Text

RELATED APPLICATION

This application claims priority to provisional application Serial No. 60/112,335, filed Dec. 15, 1998, the entire contents of which are incorporated by reference herein.

Claims

What is claimed is:

1. A method of removing *carbonyl sulfide* from a synthesis gas stream comprising the steps of:

(a) flooding a wet scrubber with substantially clean water, the step of flooding including filling the wet scrubber to a level such that water within an inner tube of the wet scrubber flows over an upper end of the inner tube;

(b) providing the synthesis gas to the wet scrubber; and

(c) bubbling the synthesis gas through the water in the wet scrubber so that the water hydrolyses the *carbonyl sulfide* to produce carbon dioxide and hydrogen sulfide, the hydrolysis occurring in the presence of a catalyst, wherein said catalyst is a product of the process that created the synthesis gas stream.

2. The method of claim 1, wherein the step of flooding the wet scrubber includes a step of raising the water level in the scrubber to substantially the same level as a location in the wet scrubber where synthesis gas is deflected down after passing through the water in a base of the scrubber.

3. The method of claim 2, wherein the step of the flooding the wet scrubber also includes a step of flooding at least one overhead tray of the wet scrubber.

4. The method of claim 2, wherein the step of flooding the wet scrubber also includes flooding an overhead output pipe of the wet scrubber.

5. The method of claim 4, further including a step (d) of allowing the synthesis gas stream to exit the wet scrubber through the flooded overhead output pipe.

6. A method of operating a wet scrubber to reduce the amount of carbonyl sulfide in a synthesis gas stream produced by the gasification of coal, the synthesis stream being provided to the wet scrubber though an input and leaving the wet scrubber though an output, the method comprising steps of:

(a) providing water though at least one water input at an input rate; and

(b) providing the synthesis gas and coal ash to the wet scrubber

(c) simultaneously with step (a) removing water from the scrubber through at least one water output at an output rate, the output rate being less the input rate, such that the wet scrubber is filled to a level such that water within an inner tube of the wet scrubber flows over an upper end of the inner tube and wet scrubber is flooded.

7. The method of claim 6, wherein the step of providing water includes providing water from a first water input and a

second water input, the first water input being located above a tray of the scrubber and the second water input being below the tray.

Description

BACKGROUND OF THE INVENTION

1. Field of the Invention

This invention relates to the removal of *carbonyl sulfide* from an effluent stream of synthesis gas and, more particularly, to removing the carbonyl sulfide in a wet scrubber without having to introduce catalysts for the hydrolysis of the *carbonyl sulfide* other than those naturally occurring in the synthesis gas stream.

2. Description of the Related Art

In situations where fossil fuels are partially oxidized, otherwise known as gasification, (e.g., in a power plant or a refinery) a gaseous mixture is produced. This gaseous mixture is commonly called "synthesis gas" and will be referred to herein as such. Synthesis gas may be used as a fuel or a feedstock for the production of chemicals. When gasifying fossil fuels such as coal or other mixtures containing coal, the synthesis gas that is produced includes particulate matter such as coal ash.

The synthesis gas may also contain a variety of sulfur-containing compounds such as hydrogen sulfide, *carbonyl sulfide*, dimethyl sulfide, carbon disulfide, and other sulfides and disulfides, and may also include ethyl and methyl mercaptan, thiols, and other sulfur-containing compounds. If the synthesis gas stream is burned as a source of energy, the emissions therefrom are regulated by governmental standards that define the acceptable limits and chemical composition of sulfur-containing compounds that may be released into the air. These regulations, while being extremely valuable to preserving the environment in which we live, create additional expenses for those in the business providing electrical energy, in particular. These expenses are occasioned by the need to remove the sulfur-containing compounds from the synthesis gas stream so that the sulfur-containing compounds or their combustion products are not released into the environment.

One such sulfur compound that is subject to output limitations through regulation is sulfur dioxide. Sulfur dioxide (SO₂) is produced when, for example, hydrogen sulfide (H₂S) or *carbonyl sulfide* (COS) is burned. Governmental agencies, on the federal, state, as well as local level, have currently been reducing through regulations the amount of SO₂ which industrial plants may release into the air.

There are currently existing methods (i.e., acid gas removal systems) that reduce the amount of H₂S, in a synthesis gas stream. In turn, reducing the amount of H₂S directly reduces the level of SO₂ that is emitted into the environment because SO₂ is formed when H₂S is burned.

However, these acid gas removal systems are not effective in removing *carbonyl sulfide* (COS). When COS is burned it is converted into SO₂ and carbon dioxide (CO₂). Thus, in order to maintain lower SO₂ emission levels, the amount of COS in the synthesis gas stream must be reduced before being treated in an acid gas removal system. Thus, the ever-tightening restrictions on SO₂ emissions have created the need for the efficient and cost-effective methods and apparatus for removing COS from synthesis gas streams.

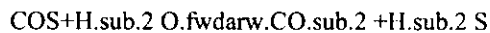
In order to reduce the amount of COS in the synthesis gas stream, a number of approaches have been proposed. The easiest to implement, when coal is the fuel, is simply to gasify coal that has a lower concentration of sulfur contained therein. If there is less sulfur in the coal, the amount of sulfur-containing products produced when the coal is gasified will be smaller. Because of the smaller amount of sulfur in the coal there is a lower concentration of sulfur containing products in the resulting synthesis gas. This, in turn, leads to a lower amount of COS being produced when the coal is gasified. Burning a synthesis gas with lower amounts of LOS, may yield SO₂ in quantities that are below the established emission limits. In that case, no processing of the synthesis gas is required in order to remove COS.

However, the price of coal is generally inversely proportional to its sulfur content; that is, the less sulfur in the coal, the more expensive the coal. The price of coal having sufficiently low sulfur concentrations such that removal of COS is not required is extreme; and in some cases (depending on market conditions) the cost of using such coal would actually create a financial loss as compared to the return based upon the energy produced from burning the coal. Further, as the world's supply of coal is further diminished, the price of low sulfur coal will continue to rise and low sulfur coal eventually will disappear.

Realizing that industry needs to gasify coal having appreciable sulfur contents, there has been much study of how to

remove COS from synthesis gas streams. However, COS is one of the most difficult sulfur compounds to remove from synthesis gas streams. It has a low boiling point similar to propane, so it is difficult to remove therefrom by fractionation. It is relatively stable toward acidic reagents and is only slowly affected by strong alkalies. Thus, the prior art methods for its removal involve complex processes and technically complex apparatuses.

Another approach taken in the prior art is the catalytic conversion of COS to H₂S via the COS hydrolysis reaction according to the following reaction:



H₂S is much more easily removed from the synthesis gas than COS by treating the H₂S in the synthesis gas stream with many common solvents. A typical process configuration utilizing COS hydrolysis is as follows.

The synthesis gas stream is output from a gasification chamber where coal is partially oxidized. On one hand, the partial oxidation of the coal provides a valuable source of energy as has been known for decades. On the other, it also produces compounds that, if not disposed of before combustion, create emissions that are unacceptable under the present emission laws.

This synthesis gas flows out of the gasification chamber through known exhaust piping. In some cases, a portion of the energy in the newly created synthesis gas, in the form of heat, is removed from the synthesis gas by a heat exchanger. The heat that is removed may be used later if desired. However, whether or not the synthesis gas is passed through a heat exchanger is optional and depends on the specific location where the process is being conducted.

Typically, synthesis gas contains excessive amounts of particulate matter. Thus, regardless of whether or not the synthesis gas is passed through a heat exchanger, the gas is then passed through a particulate removal device. The particulate matter is in the form of coal ash and the like. In order to remove this particulate matter many well-known particulate removal techniques and devices exist. For example, the device may be a dry device or a wet scrubber. Regardless of the type of device, the net effect is to remove, or at least reduce the amount of, the particulate matter from the synthesis gas. If a wet scrubber is used, water soluble-contaminants such as hydrogen chloride (HCL) are also removed from the synthesis gas stream. The particulate matter and the water-soluble contaminants should be removed in order for the hydrolysis of the COS to occur effectively, as is well known in the art. As is also well known in the art, in order for effective hydrolysis of COS to occur, the synthesis gas needs to be humidified. In the case of a wet scrubber, the scrubbing process also serves to humidify the synthesis gas. Due to the pressure in the scrubber and the temperature of the synthesis gas as it enters the scrubber, the temperature of the synthesis gas as it leaves the scrubber is typically about 300.degree.-500.degree. F.

The synthesis gas is then superheated by about 50.degree. F. in order to evaporate any entrained water in the synthesis gas. Entrained water in the synthesis gas stream can damage an expensive catalyst contained in a downstream COS hydrolysis reaction chamber (discussed below). The superheated humidified synthesis gas is then passed through a COS hydrolysis reaction chamber in order to convert the COS to hydrogen sulfide (H₂S). This hydrolysis reaction chamber contains catalysts that are required for the COS hydrolysis reaction.

The synthesis gas, now having the COS sufficiently converted so that emissions standards are not violated when the synthesis gas is burned, is then cooled to condense the water vapor therefrom. The synthesis gas must be cooled before it is passed to well known acid gas removal systems for removing the H₂S from the synthesis gas stream. Prior art acid gas removal systems typically operate at near ambient temperature (around 100.degree. F.). After removal of the H₂S, the synthesis gas may then be combusted in a steam generator (boiler), or turbine and expelled into the atmosphere. Alternatively, the synthesis gas could be used for chemical synthesis, typically after a polishing sulfur removal step.

Systems that remove COS in this manner suffer from many drawbacks. The largest of these drawbacks are the expenditures associated with them. A major cost comes from having to purchase the catalysts contained in the COS hydrolysis reaction chamber. Typical COS reaction chambers contain at least one, if not more, extremely expensive catalysts that have finite lifetimes. At present the cost of such a reaction chamber can vary from several hundred thousand dollars to numbers in the low millions of dollars. Given that these catalysts have a finite lifetime, this capital expense must be born periodically; in some cases, every four to five years. If, for example, a power plant was designed to operate for 20 years, the expense of equipping the synthesis gas treatment system with COS reaction catalysts alone could require millions of dollars for catalyst replacement.

In other prior art methods, the COS levels in a gas stream may be abated by treating the gas stream with a series of chemicals chosen such that COS is removed. An example of such a process is disclosed in U.S. Pat. No. 5,523,069 to Lin which is incorporated herein by reference. However, the methods disclosed require complex treatment of the synthesis

gas and are difficult to utilize.

SUMMARY OF THE INVENTION

The present invention overcomes the above and other drawbacks to conventional methods for the removal of *carbonyl sulfide* (COS) from synthesis gas. According to the present invention there is provided a method and system for removing COS that has a low cost and is compatible with existing synthesis gas processing apparatus so that the cost of retrofitting existing systems is low. These advantages and more are obtained, generally, by passing the synthesis gas through a wet scrubber where the wet scrubber and the overhead piping associated therewith have been flooded with water. Passing the synthesis gas through the water in the flooded wet scrubber allows the COS and the water to interact in the presence of a catalyst that is a natural by-product of the process that created the synthesis gas stream (e.g., coal ash). The vigorous and prolonged contact between the water, coal ash, and the COS in the scrubber and its overhead piping serves to promote COS hydrolysis such that the synthesis gas may be burned and its combustion products released into the atmosphere without having first been passed through a COS hydrolysis reaction chamber containing expensive catalysts.

Heretofore, it was not known, or even suspected, that one could remove COS from synthesis gas without having to pass the synthesis gas through a hydrolysis reaction chamber that contacts expensive catalysts with synthesis gas stream. Even more unexpectedly, it has been found that this can be accomplished in a conventional wet scrubber merely by flooding the wet scrubber and its associated output (overhead) piping with water. In one exemplary embodiment, the level of COS in a synthesis gas stream may be reduced without having to pass the synthesis stream gas through a COS hydrolysis reaction chamber. Further, because the synthesis gas stream is not passed through a COS hydrolysis chamber having water sensitive catalysts contained therein, there is no need to superheat the synthesis gas to ensure that the synthesis gas is not saturated with water. Also, because the synthesis gas is not superheated, there is a reduction in the amount of energy that needs to be provided to a cooling unit to remove the heat provided by superheating in order to condense most of the water out of the synthesis gas before passing it to an acid gas removal system.

In one embodiment of the present invention, a method of removing carbonyl sulfide from a synthesis gas stream is disclosed. The embodiment of this method includes steps of (a) flooding a wet scrubber with substantially clean water (b) providing the synthesis gas to the wet scrubber, and (c) bubbling the synthesis gas through the water in the wet scrubber so that the COS and the water interact in the presence of a catalyst that is a product of the process that created the synthesis gas stream.

In another embodiment of the present invention, an apparatus for removing *carbonyl sulfide* from a synthesis gas stream is disclosed. The apparatus of this embodiment includes a gasification chamber where sulfur containing compounds are partially oxidized to produce the synthesis gas stream. The apparatus of this embodiment also includes a wet scrubber that receives the synthesis gas stream and removes particulates and portions of the *carbonyl sulfide* from the synthesis gas stream. The water level in the wet scrubber is such that the *carbonyl sulfide* and water in the wet scrubber are brought into contact with each other in the presence of a catalyst that was produced when the sulfur containing compound was partially oxidized in the gasification chamber.

In another embodiment of the present invention, a method of operating a wet scrubber to reduce the amount of *carbonyl sulfide* in a synthesis gas stream produced by the gasification of coal, the synthesis stream being provided to the wet scrubber through an input and leaving the wet scrubber through an output, is disclosed. The method of this embodiment includes steps of: (a) providing water through at least one water input at an input rate and (b) simultaneously with step (a) removing water from the scrubber through at least one water output at an output rate, the output rate being less the input rate.

BRIEF DESCRIPTION OF THE DRAWINGS

The foregoing, and other objects and advantages, will be understood more clearly from the following detailed description and from the accompanying figures. This description is given by way of example only and in no way restricts the scope of the invention. This invention is illustrated with reference to the following drawings which show exemplary embodiments of the present invention. In the drawings, like reference numerals refer to the same or similar items and are arranged such that the leftmost digit of the reference numeral corresponds to the figure in which the item first appears. In the figures:

FIG. 1 is a block diagram of an example process by which the level of COS in a synthesis gas stream may be reduced;

FIG. 2 is an embodiment of a wet scrubber used by the present invention;

FIG. 3 is an embodiment of the wet scrubber shown in FIG. 2 that illustrates the level of water in the wet scrubber practiced in the prior art;

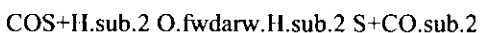
FIG. 4 is an embodiment of the wet scrubber shown in FIG. 2 in an example of a flooded state in order to remove COS from the synthesis gas stream according to the present invention; and

FIG. 5 is a block diagram of a process by which COS may be removed from a synthesis gas stream according to an embodiment of the present invention.

DETAILED DESCRIPTION

Most generally, the present invention relates to a method of removing COS from a synthesis gas stream. This is accomplished by promoting the hydrolysis of COS in a synthesis gas stream in a scrubber without having to introduce a catalyst other than those naturally occurring and present in the synthesis gas stream as a by-product of partially oxidizing (gasifying) a fossil fuel.

In general, the hydrolysis of COS contained in a synthesis gas stream occurs according to the following formula:



The reaction typically must have a catalyst to progress unless an extreme amount of heat is present.

FIG. 1 shows a simplified block diagram of an apparatus for removing COS from a synthesis gas stream. As shown, each process occurs in a block. The exact chemical process need not be completely described for each block as many of them are well known in the art. The direction the synthesis gas travels is shown by the arrows connecting the blocks of FIG. 1.

The apparatus of FIG. 1 includes a gasification chamber 102, a particulate removal device 104, a heater 106, a COS reaction chamber 108, a condenser/cooler 110, and an acid gas removal system 112. As described briefly above, the process as shown in FIG. 1 is an example process by which COS is removed from a synthesis gas stream according to the prior art. The operation of this prior art apparatus will now be described in greater detail.

First, a fossil fuel from which a synthesis gas stream may be created is introduced to the gasification chamber 102. In one example, the substance is coal that contains relatively high amounts of sulfur. However, according to this embodiment, as well as the present invention, the substance need not be limited to coal and may include any substance that produces COS when gasified. For example, the substance could be crude oil or any of its associated products such as petroleum coke or residual fuel oil, or another sulfur containing hydrocarbon-based fuel. The substance is gasified and, as it is gasified, a gas stream is created. For ease of discussion, only the gasification of coal will be discussed herein; however, it should be realized that this is by way of example only and any substance that produces a gas stream similar to that produced from coal could be used as fuel.

The gas stream created by the gasification of the fuel is referred to herein as synthesis gas. Immediately after the fuel (coal) is gasified, the synthesis gas is a particulate-laden mixture that includes several sulfur-containing compounds. The particulate material is primarily in the form of ash (i.e., coal ash) and often some residual unconverted carbon. The synthesis gas is then removed (i.e., let to escape) from the gasification chamber 102 via an outlet pipe.

Optionally, the synthesis gas may then be passed through a heat exchanger (not shown) to recover heat from the synthesis gas. As discussed above, the presence or absence of the heat exchanger is not of significant importance. However, as will be discussed in greater detail below, it may be desirable to exclude the heat exchanger so that the temperature of the synthesis gas remains high.

Next, the synthesis gas is passed through a particulate removal device 104. The device may be a wet scrubber or a dry particulate removal device. Typically, the particulate removal device 104 is a wet scrubber because the use of a dry scrubber would require an additional apparatus for humidifying the synthesis gas (not shown) so that the hydrolysis of the COS may occur and for the removal of other trace contaminants that could interfere with the hydrolysis (e.g., HCl). Thus, the particulate removal device serves two purposes. Examples of dry devices that remove particulates are electrostatic precipitators, filters and cyclones. However, because these dry devices do not effectively remove water soluble contaminants, it is preferred to use a wet scrubber. Accordingly, the term scrubbers and particulate removal device as used hereinafter both refer to wet scrubbers.

The synthesis gas is typically allowed to pass very rapidly through the wet scrubber 104. This entails allowing the gas to pass (i.e. bubble) through water that is present in the scrubber. The synthesis gas then quickly leaves the scrubber 104 through an overhead pipe. At this stage, the synthesis gas has had most of the particulate matter removed and now, additionally, has entrained water molecules present therein due to passing the synthesis gas through water. At this point, the amount of COS in the synthesis gas is relatively unchanged from the amount present when the synthesis gas left the combustion chamber 102. The wet scrubber also serves to remove chlorides from the synthesis gas. Chlorides, such as HCL, are very water soluble and thus, are easily removed from the synthesis gas with only a minimal exposure of the synthesis gas to water.

The substantially particulate-free, humidified synthesis gas must then be heated by the heater 106 to ensure that the synthesis gas is not saturated with water. Typically, the synthesis gas is heated by about an additional 50.degree. F. in the heater 106. This amount of heating typically is sufficient to cause the entrained water in the synthesis gas stream to be reduced such that the stream is not saturated.

The synthesis gas is then provided to a COS reaction chamber 108. In this chamber, the synthesis gas is exposed to catalysts that cause the above-identified chemical reaction to occur (i.e., the hydrolysis of the COS). Namely, through hydrolysis, the COS combines with the water entrained in the synthesis gas to produce H.sub.2 S and CO.sub.2.

Next, the synthesis gas is cooled in the condenser/cooler 110. The condenser 110 cools the synthesis gas so that most of the water vapor is contained and condenses and falls out of the gas. The condensed water is removed (i.e., drained) from the condenser 110.

After the condensation has occurred, the synthesis gas is then provided to the acid gas removal system 112. The acid gas removal system 112 removes both the H.sub.2 S created by the hydrolysis of the COS as well as any H.sub.2 S that was otherwise present in the synthesis gas. The synthesis gas is then burned in a combustion chamber 114. The combustion allows for the stored energy in the synthesis gas to be released and thereby, used for useful purposes, such as creating electrical power. The combustion products of the synthesis gas are then released into the atmosphere.

FIG. 2 shows an exemplary embodiment of a wet scrubber 104 that may be utilized with a prior art system of the type depicted in FIG. 1. The wet scrubber 104 of FIG. 2 may be and preferably is, utilized according to the present invention. Heretofore it has been thought that a wet scrubber such as wet scrubber 104 only served to remove particulates and some contaminants from a synthesis gas stream that is pass through the scrubber, and possibly to cool the synthesis gas stream a bit.

Synthesis gas is provided to the scrubber 104 through the input nozzle 202. At this point, the synthesis gas contains a high quantity of particulate matter. In particular, the synthesis gas contains coal ash produced when the coal was gasified. From the input nozzle 202, the synthesis gas is then passed into a dip tube 206. The dip tube 206 extends into a region of the scrubber that contains liquid water. As shown in FIG. 2, the region is defined as the region below the water level line 228. The height of water level line 228 shown in FIG. 2 is illustrated by way of example only. Typically, the water level line 228 is kept relatively low in the scrubber 104.

As the synthesis gas containing water and particulates enters the water in the scrubber 104, the synthesis gas simply bubbles through the water pool leaving most of the particulates, e.g., coal ash, in the pool. (The pool of water at the bottom of the scrubber 104 is typically called "black water" due to the color imparted to it from the coal ash and other particulates that are left there.) There are typically two locations where the water in the scrubber 104 is input from. First, there is water pool input 240 which provides water to the scrubber 104 near the lower end of the dip tube 206. Second, there is a clean water input 216 that is discussed in greater detail below.

The synthesis gas, after bubbling up through the water and crossing the water level line 228, then contacts a series of trays. As shown, two trays, first tray 212 and second tray 214, exist in the scrubber 104. However, the number of trays is highly variable and can vary from as few as one to as many as are desired for a particular scrubber.

The trays preferably contain perforations to permit the passage of the ascending synthesis gas upward through the trays. The first and second trays, 212 and 214, also include first and second downcomers 222 and 224, respectively. Clean water is introduced above the second tray 214 through clean water input 216. This water typically has not had any, or at least not enough, of a catalyst to cause a COS hydrolysis added thereto. Water that has not had enough (or any) catalyst to cause a COS hydrolysis, shall be referred to as substantially clean water. The water flows downward through the second tray 214 to the first tray 212, and further, via the first downcomer 222, into the water pool at the bottom of the scrubber 104. Thus, the descending clean water and the rising synthesis gas travel counter-current to each other from tray to tray. The synthesis gas continues to rise and then travels through a demisting pad 218 which removes most of the entrained

water from the synthesis gas and returns it the second tray 214.

The synthesis gas then rises out of the scrubber 104 through an output (overhead) pipe 220. As the synthesis gas leaves the scrubber, it is mildly humidified and is substantially particulate-free. The black water that pools in the bottom of the scrubber 104 is removed via an output 226. Water is also removed in the course of humidifying the synthesis gas stream. Typically, the water is removed (by both humidification and through output 226) at substantially the same rate at which clean water input 216 and water pool input 240 provide water to the scrubber. This ensures that the water level line 228 stays at a constant level. The level is typically significantly lower than the first tray 212 as well as the deflector cap 210. The function of the deflector cap 210 and the draft tube 208 of FIG. 2 will be discussed in greater detail below.

When operating the scrubber 104 as just described, which is the normal method of operating such a device, the amount of COS in the synthesis gas when it leaves the scrubber 104 is substantially the same as when the synthesis gas entered the scrubber 104. Thus, until the discovery that I have made as to how to operate a scrubber 104 to remove COS from a synthesis gas stream, it has been thought that a scrubber 104 was only useful for removing particulate matter and contaminants from the synthesis gas stream.

However, I have realized that by raising the level of the water level line 228 to substantially the same level as the deflector cap 210, or relatively near thereto, significant decreases in the amount of COS in the synthesis gas may be achieved. Raising the water level line 228, however, only achieves a portion of the decrease which is obtainable. By flooding the first and second trays, 212 and 214, respectively, as well as ensuring that the overhead pipe 220 is flooded with water, even larger amounts of COS may be removed.

It is believed that by flooding the scrubber 104 and the overhead pipe 220, a prolonged and more vigorous contact between the COS and the water is achieved. This prolonged contact increases the extent of the desired reaction.

However, as stated above, the reaction between COS and water is typified by the fact that it requires a catalyst in order to progress. It has been discovered that for coal, the very coal ash that the scrubber 104 is designed to remove contains an effective catalyst for the COS and water hydrolysis reaction. Thus, in order to increase the amount of time, as well as the violence with which the COS, water, and coal ash interact, it has been determined that flooding the scrubber 104 can ensure a sufficient amount of contact with required ferocity in order to spawn a reaction between the COS and the water. This allows for bubbling the synthesis gas through the water in the wet scrubber 104 so that the COS and the water interact in the presence of a catalyst that is a natural by-product of the process that created the synthesis gas stream. Advantageously, no additional catalysts need to be added to the water in order for this reaction to occur and thereby, a substantial savings in the cost of such catalysts is realized.

The scrubber 104 may be flooded in a variety of ways, however, it is believed that the most effective way to flood the scrubber is to ensure that the rate at which the influx of water provided by both the clean water input 216 and water pool input 240 exceeds the rate at which output 226 can remove water from the scrubber 104. Further, the rate at which water is input through clean water input 216 should be greater than the rate at which water may flow through the downcomers 222 and 224. This ensures that not only is the pool flooded, but also the overhead pipe 220 is flooded.

Coal ash may act as a catalyst because it contains, among other things, alumina oxide. Alumina oxide is a known catalyst for the COS/water reaction. The catalyst is present in the pool in the bottom of the scrubber 104, and by flooding the scrubber 104, a vigorous and lengthy contact between the water and the COS in the presence of catalyst can be achieved. Further, once the COS has begun reacting, with the water, further exposure to water (which still has some coal ash in it) in the overhead pipe 220 ensures that reaction the continues long, enough to convert enough COS into H₂S so that additional processing of the synthesis gas stream to remove COS need not be done before the synthesis gas is burned.

The contact between the water, COS and coal ash has been briefly described; however, this interaction will be further described with reference to FIGS. 3 and 4.

FIG. 3 shows a typical water level line 228 for operating a wet scrubber 104 as shown in FIG. 2. As can be seen, the water level line 228 is quite far below the deflector cap 210. When operating in this manner, the synthesis gas merely bubbles out of the water, leaving, the coal ash quickly behind. This, and the removal of water-soluble contaminants, has heretofore been all that was expected of such scrubbers.

Referring now to FIG. 4, an example is depicted to show how the synthesis gas interacts with the water in the scrubber 104 when the scrubber is flooded, according to an exemplary embodiment of the present invention. Flooding the scrubber 104 causes the hydraulic pressure outside the draft tube 208 to rise. When the hydraulic pressure is high, the synthesis gas

flows up the annulus between the dip tube 206 and the draft tube 208 in a three-phase (synthesis gas, water, and particulates) flow regime. This is illustrated in FIG. 4 by the bubbles 400 rising up between the dip tube 206 and the draft tube 208. Additional water is drawn into the bottom of the annulus between the dip tube 206 and the draft tube 208 when this occurs. This action produces more intimate and vigorous contact between the gas, water and particulates, and thereby results in better particulate removal. However, as described above, this intimate contact also serves to promote the hydrolysis reaction of the COS and is thus very desirable when attempting to remove COS from synthesis (as in a wet scrubber).

Further, as the water (as well as the synthesis gas) rises between the dip tube 206 and the draft tube 208 it is directed downwardly by the deflector cap 210. Typically, the gas would just continue to rise, the water and particulate matter would fall, and the contact between the water and the COS in the presence of the catalyst provided by the coal ash would cease. However, collected data indicates that a significant amount of water entrainment occurs in the area near the deflector cap 210. This indicates that the gas leaving the deflector cap impacts the water surface again (the level of the water being relatively close to the level of the deflector cap 210) causing a great deal of turbulence leading to the entrainment. Further, the high water flow into the area between the dip tube 206 and the draft tube 208 creates a vortex action that causes further vigorous contact.

Referring back now to FIG. 2, the entrained water and coal ash are carried upward with the synthesis gas to the first tray 212. The first downcomer 222 is typically not sized to accommodate both the entrained water in the synthesis gas and the flowing downward from the second downcomer 224. This leads to the flooding of the first tray 212. Synthesis gas, water and coal ash pass through the first tray 212 up to the second tray 214 which is has also been flooded. They entire overhead volume of the scrubber 104 is eventually flooded, including the overhead pipe 220. However, the additional water now contained in the overhead pipe 220 will require some sort of water removal means downstream from the scrubber 104, for example, the condenser 110 of FIG. 1.

Thus, it appears, that wholly unexpectedly I have achieved a method for reducing the amount of COS present in a synthesis gas stream by flooding a prior art wet gas scrubber.

The practical implications of this discovery are considerable. As described above with respect to FIG. 1, the removal of COS from synthesis gas typically involves using an expensive COS reaction chamber 108. Because of the discovery that COS may be removed from a stream of synthesis gas using only a scrubber having clean water in it, the expensive COS reaction chamber may be removed.

This may also be seen with reference to FIG. 5, which shows the limited number of blocks required to carry out the removal of COS from synthesis gas when a wet scrubber is operated in the manner discussed above (i.e., flooded). As shown in FIG. 5, only five of the seven blocks shown in FIG. 1 are needed to remove COS from a synthesis gas stream produced by gasification of coal having some level of sulfur contained in it. In particular, the process for removing COS according to one embodiment includes gasifying the coal in a gasification chamber 102 which produces a stream of synthesis gas containing particulate matter (e.g., coal ash) and COS, removing both particulate matter and COS from the synthesis gas stream in a scrubber 104 (when the scrubber is operated in accordance with the present invention), cooling the output of the scrubber 104 in a condenser 110 to remove water from the synthesis gas stream, providing the synthesis gas stream to an acid gas removal system 112 to remove the H₂S from the synthesis gas, and burning the synthesis gas in a combustion chamber 114 before it is released into the atmosphere.

As discussed in greater detail above, when sulfur-containing coal is gasified in the gasification chamber 102, a stream of synthesis gas is produced that contains particulate matter as well as amounts of COS, that when burned, would produce amounts of SO₂ in excess of what current emissions laws allow to be released into the atmosphere.

Optionally, the synthesis gas may then be provided to a heat exchanger (not shown) in order to extract heat energy from the synthesis gas stream for use in other applications or steps in the treatment of the synthesis gas stream. However, this heat exchanger is not necessary. In some cases, the presence of a heat exchanger may actually serve as a detriment to the removal COS in the scrubber 104. The hydrolysis reaction of COS actually is more efficient if conducted at higher temperatures, at least up to the point of thermodynamic equilibrium. If the heat exchanger removes too much of the heat from the synthesis gas stream, the gas stream may be cooler than allows for the optimal hydrolysis of the COS in the synthesis gas stream. However, conditions may vary such that the need for the energy from the synthesis gas stream removed from by a heat exchanger outweighs the reduction in hydrolysis efficiency and therefore, a heat exchanger is preferable. Regardless of whether a heat exchanger is present, if the scrubber 104 is operated in a manner in accordance with the present invention, COS may be removed from the synthesis gas stream in the scrubber 104.

The synthesis gas is then passed to the scrubber 104 which is preferably a wet scrubber having only clean water provided

thereto. The scrubber 104 removes chlorides and particulate matter from the synthesis gas no matter how it is operated. However, if the scrubber 104 is operated in accordance with the present invention, substantial amounts of COS are also removed therein.

At this point, the synthesis gas is provided directly to the condenser 110 to remove entrained water from the synthesis gas stream. Note that, as compared to FIG. 1, providing the synthesis gas directly to the condenser 110 bypasses both the heater 106 (not shown in FIG. 5) and the COS reaction chamber 108 (also not shown in FIG. 5). The profound advantages to bypassing these two items are readily apparent when one considers the costs involved with obtaining and operating them.

For example, because the COS reaction chamber is not needed, there is no need to superheat the synthesis gas stream to ensure that it is not water saturated. Thus, the heater 106 of FIG. 1 need not be purchased, resulting in a capital expenditure savings at least equal to the cost of a suitable heater. Further, because there is no heater, the expense of operating a heater is avoided. This results in saving the cost of operating a heater such as, for example, electricity or fuel needed to operate the heater and maintenance of the heater. Additionally, the monitoring equipment that is typically present to ensure the heater is operating correctly is no longer needed.

However, the most profound savings comes from not having to purchase catalysts for the COS reaction chamber. As discussed above, these chambers contain extremely expensive catalysts and the cost of purchasing such a unit can be upwards of a couple million dollars. Further, the catalysts in the reaction chambers must be periodically replaced, adding additional costs.

Additionally, removing both of these units saves in the physical space required to contain a system to cleanse synthesis gas. As the cost of physical space increases, such as due to inflation, it is preferable to use as much space as possible for revenue generating activities instead of compliance measures. If two space-consuming devices are not required, the space that normally would be required could be used for other purposes.

Thus, it is quite apparent that the unexpected discovery that COS may be removed in existing wet scrubbers, and the resulting reduction in capital expenditures occasioned by this discovery, holds great financial as well as environmental rewards.

Also, in some cases the amount of COS removed in the wet scrubber when operated in accordance with the present invention, may not be sufficient to meet certain environmental standards or for the creation other of end uses of synthesis gas such as chemical manufacture. In these cases, it may still be necessary to employ a heater and COS reaction chamber. However, because the level of COS in the synthesis gas has been reduced significantly in the scrubber 104 as operated in accordance with the present invention, the efficiency of the COS reaction chamber need not be as great. Thus, the COS reaction chamber may be a cheaper version that is not as efficient. This reduction in expense alone could be quite significant. These advantages all flow from the discovery that operating a wet scrubber so that water and COS vigorously contact one another in the presence of the coal ash that is a natural by-product of gasifying coal, serves to reduce the amount of COS in a synthesis gas stream.

EXAMPLE

The following example is presented to further illustrate and explain the present invention and should not be taken as limiting in this regard. This example summarizes the results of tests performed using a synthesis gas treatment system having a conventional wet scrubber similar to the one illustrated in FIGS. 2-4. The wet scrubber in this case actually comprised two parallel wet scrubbers, each receiving approximately one-half of the synthesis gas stream.

Typically, each scrubber is operated having a water level line approximately 42 inches above the base of the scrubber. The total COS concentration in the synthesis gas stream at the output of both scrubbers is in the range of 320 ppm.

When the water level of one of the scrubbers was raised to a relatively high level, approximately 55-60 inches (e.g., the scrubber was flooded), the concentration of COS in the synthesis gas stream fell to about 270 ppm. This represents about a 16% reduction in the amount of COS in the synthesis gas stream.

Next, the water level in the second scrubber was raised to a relatively high level, approximately 55-60 inches. This led to a further decrease in the COS concentration; the reduction was approximately another 50 ppm. Thus, the concentration COS, when both scrubbers were being operated according to the present invention, dropped approximately 100 ppm to a level of 220 ppm. This translates into approximately a 30% drop in the COS contained in the synthesis gas after passing

through the scrubbers.

While various embodiments and examples of the present invention have been described above, it should be understood that they are presented by way of example only, and are not intended as limitations. For example, the exact configuration of the scrubber and the water levels described therein are not the only ones where the present invention may operate; the only requirement is that, in the scrubber and its overhead piping, the synthesis gas and water come into intimate and vigorous contact in the presence of a catalyst, such as coal ash. Further, coal ash has been explained as being a catalyst that naturally occurs when coal is gasified; other naturally occurring catalysts may exist in, for example, the gasification of crude oil or any other hydro-carbon based fuel; and the present invention is equally compatible with a system for removing COS from a gas stream produced in the burning thereof. Accordingly, the breadth and the scope of the present invention should not be limited by any of the above-described exemplary embodiments or examples, but are defined only in accordance with the following claims and their equivalents.

* * * * *

APPENDIX E - AWARDS

The Ecological Society of America Corporate Award

The Timer Powers Conflict Resolution Award from the State of Florida

The Florida Audubon Society Corporate Award.

1996 Association of Builders and Contractors award for construction quality.

The 1997 Power plant award by Power Magazine.

Induction into the Power Magazine Power Plant Hall of Fame

APPENDIX F - VISITORS

Polk Visitors

Since its inception Polk Power Station has been of interest to a variety of people and institutions. Visits were restricted in the construction phase and initial start-up. These restrictions were lifted in 1997, and Polk Power Station has averaged over 400 visitors per year. Over 2,500 visitors have toured the IGCC facility here at Polk. Many countries are represented by the individuals, companies, universities, research groups, legislators, regulatory groups, governmental agencies, utilities and others who came to visit Polk Power Station. Below are a few of the groups who have visited and some of the countries they represented.

Countries Represented

Australia	Brazil	China
England	France	Germany
Guatemala	Italy	Japan
Korea	Mexico	Pan American States
Spain	Taiwan	Turkey
United Kingdom	Venezuela	

Some Visiting Organizations

Air Gas Carbonics	Air Products
BASF	Black & Veach
BOC Gases	Calpine
Center for Energy and Economic Development	Charah Environmental
Chevron	Citgo
Clark Environmental	Clean Air Task Force
Congressional Aids	Congressmen
CRIEPI (Japan)	DeMag Deleval
Department of Energy	Dominion Power
Environmental Protection Agency	EPRI
Exxon	Formosa Plastics
General Electric	Global Energy
Institute of Applied Energy (Japan)	John Rich Co.
Kinectrics	Legislators
Messer Group	Metcalf & Eddy
Mobil	NARUC
National Public Radio	New York Power Authority
Peabody Coal	Peoples Gas
Progress Energy	Rochester Gas & Electric
Salof Industries	Senators
Shell	Tennessee Valley Authority
Texaco	University of Kentucky
University of South Florida	Williams Co.

APPENDIX G - BIOMASS TEST REPORT

Biomass Test At Polk Power Station Unit 1 IGCC

SUMMARY

Part of a closed loop biomass crop was recently harvested to produce electricity in Tampa Electric's Polk Power Station Unit #1. No technical impediments to incorporating a small percentage of biomass into Polk Power Station's fuel mix were identified. Appropriate dedicated storage and handling equipment would be required for routine biomass use.

TEST DETAILS

Polk Unit #1 is an integrated gasification combined cycle (IGCC) power plant. IGCC is a new approach to generating electricity cleanly from solid fuels such as coal, petroleum coke, and now biomass. Solid fuel is first ground into a water slurry which is pumped into the gasifier. There it is converted into a high pressure combustible gas from which pollutants such as particulates and sulfur compounds are easily removed. The clean gas then fuels a combined cycle consisting of a combustion turbine plus a steam turbine. The combustion turbine operates much like a jet engine to produce electricity. The steam turbine produces additional electricity from the system's waste heat, making the combined cycle the most efficient way to produce electricity on a large commercial scale.

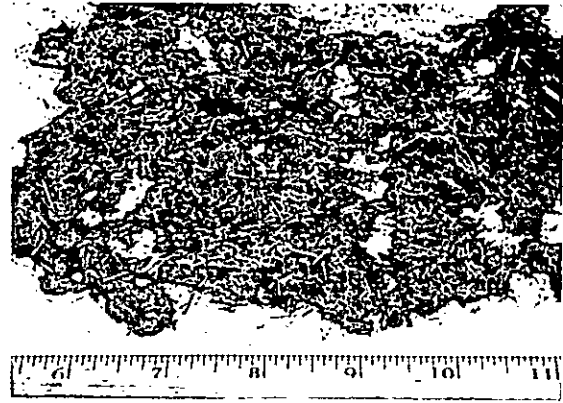
The closed loop biomass crop is a 600 tree eucalyptus grove planted in 1996 by Common Purpose, Inc., on land provided by the Tampa Port Authority. 10% of the crop was harvested in late December 2001. The felled trees were cut into 4 foot logs. These were processed through a portable commercial hammer mill and trommel screen. After 5 passes through the mill and screen, the trees were reduced to 8.8 tons of material with the consistency of coarse sawdust. The particles needed to be this fine to avoid plugging the pumps and screens in the power plant's fuel slurry feed system.



Biomass Crop – Eucalyptus Grove (Processing Equipment in Foreground)

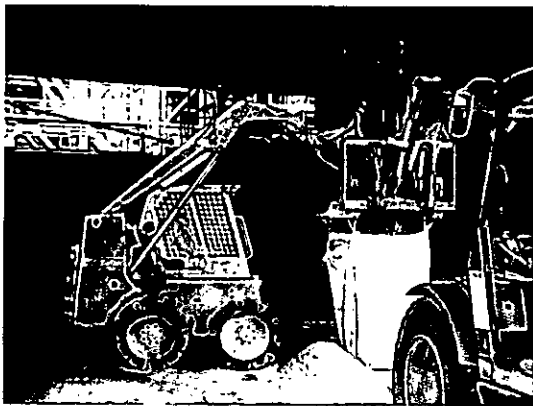


Eucalyptus Logs



Eucalyptus Fuel After 5th Mill Pass

The fuel was transported by special closed trailer to Polk Power Station located in the southwest corner of Polk County. A slag bin that usually holds the non-combustible residual mineral matter from coal gasification had been thoroughly cleaned to receive the biomass and serve as the staging area. Expensive automated solids handling and feeding equipment that would be used for long term commercial operation was not installed for the brief test. Instead, the biomass was manually loaded into 22 tote sacks which held an average of 800 lb each. The totes were emptied over an 8½ hour test period into a stirred tank which supplies some of the water and recycled fines to the plant's coal/water slurry preparation system.



Loading Tote Sacks



Emptying Totes Into Mixing Tank

The test went very smoothly. The biomass comprised 1.2% of the plant's fuel during the 8½ hours it was being fed. Plant performance during the biomass test was statistically indistinguishable from operation on the plant's base fuel, a blend of coals and petroleum coke. The biomass yielded 860 kW (7700 kWh total) of electricity during the test period based on the relative heating values and flow rates of the biomass and base fuel. Overall test results are summarized in Table 1 below.

TABLE 1: Biomass Test – Overall Results

	Base Fuel	Biomass	Total/Average
Fuel Feed Rate (Lb/Hr As Received)	164,840	1,945	166,786
Moisture Content (Wt %)	7.82%	46.8%	8.27%
Higher Heating Value (BTU/ Lb As Received)	13,322	4,424	13,218
Higher Heating Value (MMBTU/Hr)	2196	8.6	2205
Net Power Production (kW)	219,640	860	220,500

There was only 1 minor incident during the test. Despite the extreme care taken to exclude all oversized material during biomass preparation, 3 wood chips did find their way into the 21st tote. These plugged the suction to one of the pumps in the slurry feed system. The chips were easily removed in a few minutes without any interruption to gasification or power production. A commercial biomass feed system could be easily configured to prevent this from recurring.



From the positive test results, we conclude there is no technical impediment to incorporating small percentages of biomass into the Polk Power Station IGCC fuel mix. The biomass feeding method used for the test was obviously very labor intensive. Dedicated receiving, storage, handling, and feeding systems would be required for practical routine biomass gasification.

Figure 1 on the following page is a block flow diagram of the Polk Power Station IGCC syngas fuel production system. Table 2 shows the overall mass balance across this system. Tables 3 and 4 provide compositions and elemental balances for major constituents (C, H, S, N, O, Ash) of all the individual streams.

Table 5 presents the detailed analysis of the biomass and of the coal/petroleum coke blend, the plant's normal feedstock. Other documentation of the test such as the log of the biomass feed rate and certified truck scale tickets of the biomass delivery to the plant are available upon request.

Polk Power Station IGCC Syngas Fuel Production System

FIGURE 1 – Block Flow Diagram

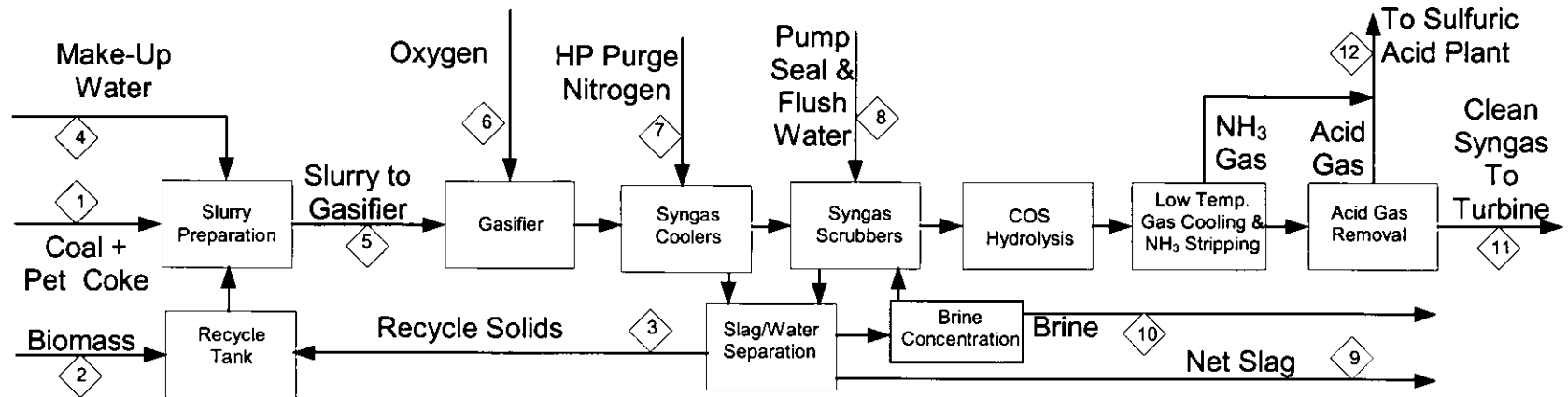


TABLE 2 – Overall Mass Balance During Biomass Test

INPUT (FEED) STREAMS		
Stream Number	Stream Description	Flow (KPPH)
1	Coal / Petroleum Coke Blend	164.84
2	Biomass	1.95
4	Make-Up Water To Slurry	16.50
6	Oxygen To Gasifier	166.94
7	High Pressure Purge/Sootblowing N ₂	11.07
8	Pump Seal/Instrument Flush Water	19.49
TOTAL SYSTEM INPUT STREAMS		380.79

PRODUCT (OUTPUT) STREAMS		
Stream Number	Stream Description	Flow (KPPH)
9	Slag	17.36
10	Brine	.02
11	Clean Syngas To Combustion Turbine	337.78
12	Acid and NH ₃ Gas To Sulfuric Acid Plant	25.62
TOTAL SYSTEM OUTPUT STREAMS		380.78

KEY INTERNAL STREAMS		
Stream Number	Stream Description	Flow (KPPH)
5	Slurry To Gasifier	264.40
3	Recycle Solids To Slurry Preparation	81.12

TABLE 3 – Slurry Preparation Area Stream Flows and Compositions

	Stream Number	1	1	2		3	4	5
	Units	COKE + COAL (Lab)	COKE + COAL (Calculated)	BIOMASS	COMBINED FRESH FUELS	RECYCLE SOLIDS	MAKE-UP WATER	SLURRY TO GASIFIER
COMPOSITION								
C	Wt % Dry	82.88	82.24	49.18	82.02	66.26		80.68
H	"	4.50	4.71	5.78	4.71	0.29		4.34
N	"	1.85	1.83	0.24	1.81	0.95		1.74
S	"	2.99	3.15	0.06	3.13	2.31		3.06
O	"	3.53	3.67	39.42	3.92	0.00		3.58
ASH	"	4.25	4.40	5.32	4.41	30.19		6.60
TOTAL	"	100.00	100.00	100.00	100.00	100.00		100.00
MASS FLOW								
SUBTOTAL FLOW		KPPH DRY	151.950	151.950	1.035	152.985	14.196	167.181
H2O	Wt % AR	7.82	7.82	46.8	8.27	82.50		36.77
H2O	KPPH	12.891	12.891	0.910	13.801	66.924	16.496	97.220
TOTAL FLOW		KPPH AR	164.841	164.841	1.945	166.786	81.120	264.401
C	Dry Lb/Hr	125936	124962	509	125471	9406		134877
H	"	6838	7150	60	7210	41		7251
N	"	2811	2774	2	2777	135		2911
S	"	4543	4791	1	4791	328		5119
O	"	5364	5582	408	5990	0		5990
ASH	"	6458	6691	55	6746	4286		11031
Ar	"	0	0	0	0	0		0
SUBTOTAL-Dry Solids		"	151950	151950	1035	152985	14196	167181
WATER / MOISTURE		"	12891	12891	910	13801	66924	97220
TOTAL		"	164841	164841	1945	166786	81120	264401
HEAT CONTENT								
Calculated HHV	BTU/Lb (Dry)	14491	14511	8419	14470	9698		14065
Measured HHV	BTU/Lb (Dry)	14435		8213		9811		13990
Balance HHV	BTU/Lb (Dry)	14452	14452	8315	14411	9701		14011
Balance HHV	BTU/Lb (AR)	13322	13322	4424	13218	1698		
Balance HHV	MMBTU/Hr	2196	2196	8.60	2205	138		2342

Notes: Calculated HHV is by the Mason Formula. Difference between "Lab" and "Calculated" Coke+Coal composition is within sampling and analytical accuracy range.

TABLE 4 – Gasification System Stream Flows and Compositions

STREAM NUMBER		GASIFICATION SYSTEM INPUTS					GASIFICATION SYSTEM OUTPUTS					
		5	6	7	8		9	3	10	11	12	
GAS STREAMS	UNITS	SLURRY TO GASIFIER	OXYGEN	HP PURGE NITROGEN	SEAL & FLUSH WATER	TOTAL SYSTEM INPUT	SLAG	RECYCLE SOLIDS	BRINE (NH4Cl)	CLEAN SYNGAS	ACID GASES	TOTAL SYSTEM OUTPUT
CO	VOL %		0.00	0.00						44.72	2.06	
H2	VOL %		0.00	0.00						36.02	0.52	
CH4	VOL %		0.00	0.00						0.02	0.02	
CO2	VOL %		0.00	0.00						15.01	66.42	
N2	VOL %		1.08	99.99						3.33	0.00	
Ar	VOL %		2.01	0.00						0.65	0.00	
H2O	VOL %		0.00	0.00						0.21	5.26	
H2S	VOL %		0.00	0.00						0.01	21.02	
COS	VOL %		0.00	0.00						0.01	0.06	
NH3	VOL %		0.00	0.00						0.00	4.62	
O2	VOL %		96.90	0.01						0.00	0.01	
TOTAL	VOL %		100.00	100.00						100.00	100.00	
MOLECULAR WT	LB/MOLE		32.12	28.02						21.10	38.76	
FLOW	KSCFH		1972.6	149.9						6075.5	250.9	
SOLID AND LIQUID STREAMS												
C	WT %	80.68					42.37	66.26				
H	WT %	4.34					0.31	0.29	7.49			
N	WT %	1.74					0.44	0.95	26.22			
S	WT %	3.06					1.47	2.31				
O	WT %	3.58					0	0.00				
ASH	WT %	6.60					55.41	30.19	66.29			
TOTAL	WT %	100.00					100.00	100.00	100.00			
DRY FLOW	KPPH	167.181					12.149	14.196	0.021			
H2O	WT %	36.77					30	82.50				
H2O FLOW	KPPH	97.220			19.489		5.207	66.924				
TOTAL FLOW	KPPH	264.401					17.356	81.120				
ELEMENTAL FLOWS / BALANCE												
C	LB/HR	134877	0	0		134877	5148	9406		114880	5443	134877
H	LB/HR	18130	0	0	2181	20311	620	7530	2	11709	450	20311
N	LB/HR	2911	1580	11066		15558	53	135	6	14936	428	15558
S	LB/HR	5119	0	0		5119	179	328		144	4469	5119
O	LB/HR	92331	161177	1	17308	270817	4624	59435		191926	14832	270817
ASH	LB/HR	11031	0	0		11031	6732	4286	14	0	0	11031
Ar	LB/HR	0	4184	0		4184				4184	0	4184
TOTAL	LB/HR	264401	166941	11067	19489	461898	17356	81120	21	337779	25623	461898

TABLE 5 – Feedstock Analysis

	Fuel	Coal/Coke Blend	Biomass
	Units		
Total Moisture	Wt %	7.82	46.8
Ultimate Analysis			
Ash	Wt % (Dry Basis)	4.25	5.32
C	Wt % (Dry Basis)	82.88	49.18
H	Wt % (Dry Basis)	4.5	5.78
N	Wt % (Dry Basis)	1.85	0.24
S	Wt % (Dry Basis)	2.99	0.06
O	Wt % (Dry Basis)	3.53	39.42
Heating Value			
Measured HHV	BTU/Lb (Dry Basis)	14435	8213
Calculated HHV	BTU/Lb (Dry Basis)	14490	8419
Miscellaneous			
Chlorine	Wt % (Dry Basis in Coal)	0.02	0.07
Fluorine	Wt % (Dry Basis in Coal)	<0.01	34
Chromium	PPM (Wt) In Ash	136	85.9
Vanadium	Wt % In Ash	2.286	0.63
Nickel	ug/g dry coal	166	1300
Arsenic	ug/g dry coal	2.1	35.3
Mercury	ug/g dry coal	0.03	0.02
Lead	ug/g dry coal	2.6	116
Beryllium	ug/g dry coal	1.3	9.2
Ash Minerals			
CrO	Wt % In Ash	0.02	0.01
V2O5	Wt % In Ash	4.08	1.12
NiO	Wt % In Ash	0.50	0.17
As2O3	Wt % In Ash	0.0065	0.0047
Hg	Wt % In Ash	0.000071	0.000002
PbO	Wt % In Ash	0.0066	0.0125
BeO	Wt % In Ash	0.0085	0.0026
SiO2	Wt % In Ash	49.21	40.7
Al2O3	Wt % In Ash	20.52	4.98
TiO2	Wt % In Ash	0.93	0.29
Fe2O3	Wt % In Ash	12.89	6.12
CaO	Wt % In Ash	3.34	22.31
MgO	Wt % In Ash	1.91	1.85
Na2O	Wt % In Ash	0.57	1.41
K2O	Wt % In Ash	2.04	3.64
P2O5	Wt % In Ash	0.16	1.44
SO3	Wt % In Ash	3.4	3.67
Sum of Determined Minerals	Wt % In Ash	99.07	87.73
Undetermined Ash Minerals	Wt % In Ash	0.93	12.27

APPENDIX H - MATERIAL SAFETY DATA SHEETS

Fine Slag

Coarse Slag

Ammonium Chloride

Ammonium Chloride Solution

Sulfuric Acid

Material Safety Data Sheet		PC/C Fine Slag Polk Power Station
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1.0 General Information

Item Name: Fine Slag
 Company's Name: Tampa Electric Company - Polk Power Station
 Company's Address: P.O. Box 111
 Company's City: Tampa
 Company's State: Florida
 Company's Zip Code: 33601
 Company's Emergency Phone Number: (813) 228-4111
 Company's Information Phone Number: (813) 228-4111
 Date of MSDS Preparation: March 3, 2000

Signature of Preparer: K. Tapscott

2.0 Ingredients/Identity Information

Proprietary: No

Ingredients:

Hazardous Component	OSHA PEL	ACGIH TLV	IDLH	CAS Number	%
Silica (SiO ₂)	133 mg/M ³	3 mg/M ³	3,000 mg/M ³	7631-86-9	40-60
Alumina (Al ₂ O ₃)	5 mg/M ³	10 mg/M ³	NE	1344-28-1	15-35
Ferric oxide (Fe ₂ O ₃)	10 mg/M ³	5 mg/M ³	2,500 mg/M ³	1309-37-1	5-25
Calcium oxide (CaO)	5 mg/M ³	2 mg/M ³	25 mg/M ³	1305-78-8	1-10
Potassium oxide (K ₂ O)	NP	NP	NE	NE	1-5
Sodium oxide (Na ₂ O)	NP	NP	NE	NE	1-5
Balance of ingredients					<1
Nuisance Dust (Total)	15 mg/M ³	10 mg/M ³	NP-Not Published		
Nuisance Dust-Respirable	5 mg/M ³	5 mg/M ³	NE-Not Established		

Material Safety Data Sheet		PC/C Fine Slag Polk Power Station
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3.0 Physical/Chemical Characteristics

Boiling Point	N/A	Specific Gravity	2.7 g/cc
Vapor Pressure (mm Hg)	N/A	Melting Point	>2,300 °F
Vapor Density (Air = 1)	N/A	Evaporation Rate (Butyl acetate = 1)	N/A

N/A Not Applicable

Solubility in Water: Slight
 Appearance and Odor: Black "sand-like" solid with no appreciable odor when dry. An ammonia-like odor may be present with wetted material.

4.0 Fire and Explosion Data

Flash Point	N/A	Flammable Limits	N/A
Lower Explosive Limit (LEL)	N/A	Upper Explosive Limit (UEL)	N/A

Extinguishing Media: Use media suitable for surrounding fire.

Special Fire-fighting Procedures: N/A

Unusual Fire & Explosion Hazards: Can be used as a fuel for a high temperature boiler.

Material Safety Data Sheet		PC/C Fine Slag Polk Power Station
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5.0 Reactivity Data

Stability:	Stable	Stable under anticipated storage conditions.	
Hazardous Polymerization	Will not occur	Conditions to avoid:	N/A

Incompatibility: Hydrofluosilic and hydrofluoric acids.

No Hazardous Decomposition or Byproducts are anticipated for the material.

6.0 Health Hazard Data

Route(s) of Entry:	Inhalation - Yes	Skin - Yes	Ingestion - Yes
Carcinogenicity:	NTP - No	IARC Monographs - No	OSHA Regulated - No
Boiler slag is not a recognized carcinogen. Free silica comprises <0.1%.			

Health Hazards:
Overexposure may cause symptoms of respiratory, eye, skin, and nose irritation. Persistent exposure to airborne dust may decrease pulmonary functions. Prolonged exposure may cause skin irritation.

Signs and Symptoms of Exposure:
The material can be drying and irritating to mucous membranes.

Medical Conditions Generally Aggravated by Exposure:
Pre-existing conditions, particularly respiratory, may be aggravated by prolonged exposure.

Emergency and First Aid Procedures:
Eyes: Flush with water for at least 15 minutes. Skin: Flush with water for at least 15 minutes. Inhalation: Remove to fresh air. Ingestion: Rinse mouth with water. Do not induce vomiting. Get medical attention.

7.0

Precautions for Safe Handling and Use

Steps to Be Taken in Case Material is Released or Spilled:

Vacuum or wet sweep into an appropriate container.

Waste Disposal Method:

Disposal should follow all environmental regulations. Dispose of in accordance with local, state, and federal regulations.

Precautions to Be Taken in Handling and Storing:

Avoid creating an airborne dust. Wetting with water will reduce airborne dust.

Other Precautions:

None.

8.0

Control Measures

Respiratory Protection:

Respiratory protection is not required below the PEL. A dust mask or half-mask air-purifying respirator with HEPA cartridge is recommended for exposures between 5 and 50 mg/M³. Between 50 and 500 mg/M³, a full-face air-purifying respirator with HEPA cartridge is recommended. Exposures above 500 mg/M³ require use of supplied air.

Ventilation:

Use local exhaust where feasible. Use mechanical ventilation as required to maintain employee exposure below the PEL/TLV.

Personal Protective Equipment:

Use cotton work gloves with dry material. Use acid-resistant if material is wet. Protective goggles or side-shield safety glasses. Wearing of contact lenses is not recommended.

Work/Hygiene Practices:

Wash hands/face prior to eating, drinking, or applying cosmetics.

Material Safety Data Sheet		PC/C Fine Slag Polk Power Station
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9.0	U.S. DOT Classification
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Material is not regulated by U.S. DOT as a hazardous material.

Material Safety Data Sheet		PC/C Course Slag Polk Power Station
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1.0 General Information

Item Name: Course Slag
 Company's Name: Tampa Electric Company - Polk Power Station
 Company's Address: P.O. Box 111
 Company's City: Tampa
 Company's State: Florida
 Company's Zip Code: 33601
 Company's Emergency Phone Number: (813) 228-4111
 Company's Information Phone Number: (813) 228-4111
 Date of MSDS Preparation: March 3, 2000

Signature of Preparer: *K. Tapscott*

2.0 Ingredients/Identity Information

Proprietary: No

Ingredients:

Hazardous Component	OSHA PEL	ACGIH TLV	IDLH	CAS Number	%
Silica (SiO ₂)	133 mg/M ³	3 mg/M ³	3,000 mg/M ³	7631-86-9	10-25
Alumina (Al ₂ O ₃)	5 mg/M ³	10 mg/M ³	NE	1344-28-1	5-15
Ferric oxide (Fe ₂ O ₃)	10 mg/M ³	5 mg/M ³	2,500 mg/M ³	1309-37-1	1-15
Calcium oxide (CaO)	5 mg/M ³	2 mg/M ³	25 mg/M ³	1305-78-8	1-10
Potassium oxide (K ₂ O)	NP	NP	NE	NE	1-5
Sodium oxide (Na ₂ O)	NP	NP	NE	NE	1-5
Balance of ingredients					<1
Nuisance Dust (Total)	15 mg/M ³	10 mg/M ³	NP-Not Published		
Nuisance Dust-Respirable	5 mg/M ³	5 mg/M ³	NE-Not Established		

The following notes are useful in interpreting Figure 6-1:

1. All numbers on the diagram reflect energy flows in MMBTU/Hr except where otherwise indicated.
2. Sensible heat flows are referenced to ambient temperature
3. The coal, flyash, and syngas energy flows are based on higher heating value (HHV)
4. The low level energy stream from the process plant to the power plant consists of the sensible heat delivered to the clean syngas in the clean gas preheater and the sensible heat delivered to the steam turbine condensate in the vacuum flash overhead condenser and steam turbine condensate heater.
5. HP and MP steam energy flow from the process plant to the power block reflects the net energy delivered to the steam cycle from the process plant. Specifically, it is the enthalpy of the steam from the process plant minus the enthalpy of the economized feedwater from the power block used to produce it. Likewise, the LP steam heat flow from the power block to the process plant reflects the net energy delivered to the process plant.
6. The 375 MMBTU/Hr in the HRSG stack stream consists of 244 MMBTU/Hr of sensible heat plus 131 MMBTU/Hr of latent heat of vaporization of the water formed from syngas combustion. This latent heat must be included since the coal, flyash, and syngas stream energy flows are reported as higher heating value (HHV) where the reference state for water is liquid. If the diagram were based on lower heating value (LHV), those four numbers would change as shown in Table 6-1 below. In addition, we would have to consider the energy of the water consumed in the gasification reactions which enters the system as a liquid. Water vapor (not liquid) is the reference state when using LHV as the basis, so that stream would have a negative value as shown in the table.

Stream	Units	HHV	LHV
Coal	MMBTU/Hr	2433	2348
Water Consumed	MMBTU/Hr	0	-43
Syngas	MMBTU/Hr	1761	1633
Slag & Flyash	MMBTU/Hr	69	68
HRSG Exhaust	MMBTU/Hr	375	244
Net Efficiency	%	35.4	36.7
Net Heat Rate -Coal	BTU/kWh	9643	9306
Net Heat Rate -Syngas	BTU/kWh	6988	6480

Table 6-1 LHV vs. HHV Data and Efficiency

7. Figure 6-1 was based on data gathered during full load operation on 100% Peabody Camp Kentucky #9 coal in November 1999. 57% of the settler bottoms flyash was being recycled at the time. Carbon conversion was 94.4% per pass and 96.0% overall. Indicated refractory liner life was 2.42 years.

8. Performance indicated in Figure 6-1 was adjusted for two important changes in the plant configuration and one important operational change since the data was taken:

- The brine concentration system falling film evaporator was being operated as a direct steam driven evaporator at the time the data was taken. It has since been returned to the more efficient vapor compression cycle configuration (See Section 1.3.5.6.2)
- Some steam traps were malfunctioning by bypassing a significant amount of steam at the time the data was taken. These traps have since been replaced with condensate pots operated on level control to prevent this steam loss.
- The ammonia stripper was not being operated when the data was taken. It is now routinely operated to provide ammonia-free water for the lockhopper system (See Section 1.3.5.6.1)

Steam distribution in the process plant before and after these changes is shown in Figures 6-2 and 6-3 respectively. Almost 40,000 lb/hr of medium pressure (410 psig) and low pressure (65 psig) steam was saved as a result of these changes. This steam is now being used to generate an additional 2.5 MW in the steam turbine. The brine compressor consumes 500 kW, so the net (adjusted) output is 2.0 MW higher than when the data was actually taken. These adjustments improved the reported heat rate by 87 BTU/kWh and efficiency by 0.3%.

9. Some of the energy losses shown on Figure 6-1 are recoverable. Much of the 69 MMBTU/Hr lost with the slag and flyash can be recovered by recycling more flyash. However, as noted in Section 5, at some point, the energy recovered through flyash recycle is almost completely offset by the additional auxiliary power used to generate the extra oxygen needed for processing this lower quality fuel. Recovering this 69 MMBTU/Hr by recycling would not offer a significant efficiency boost in this case since carbon conversion is already high and the quality of the fines available for recycling is relatively low. However, recycling will reduce the burdensome slag disposal cost, so there is a strong economic incentive to do so.
10. The HRSG stack temperature was 333°F at the time the data was taken (a typical value) compared to the plant design of 262°F. This temperature difference reflects 70 MMBTU/Hr lost from the cycle. 40 MMBTU/Hr of this loss resulted directly from removing the raw gas / clean gas exchangers in 1997 (See Section 1.3.4.4.1). At least some of this 70 MMBTU/Hr can be effectively recovered in a syngas saturator to improve heat rate and to help meet lower NO_x emissions restrictions (Section 1.4.2.6.1). Just how much of the total 70 MMBTU/Hr can ultimately be recovered in this manner depends on how low the stack temperature can be driven before sulfur deposits in the HRSG become unmanageable (See section 1.4.3.5.1).

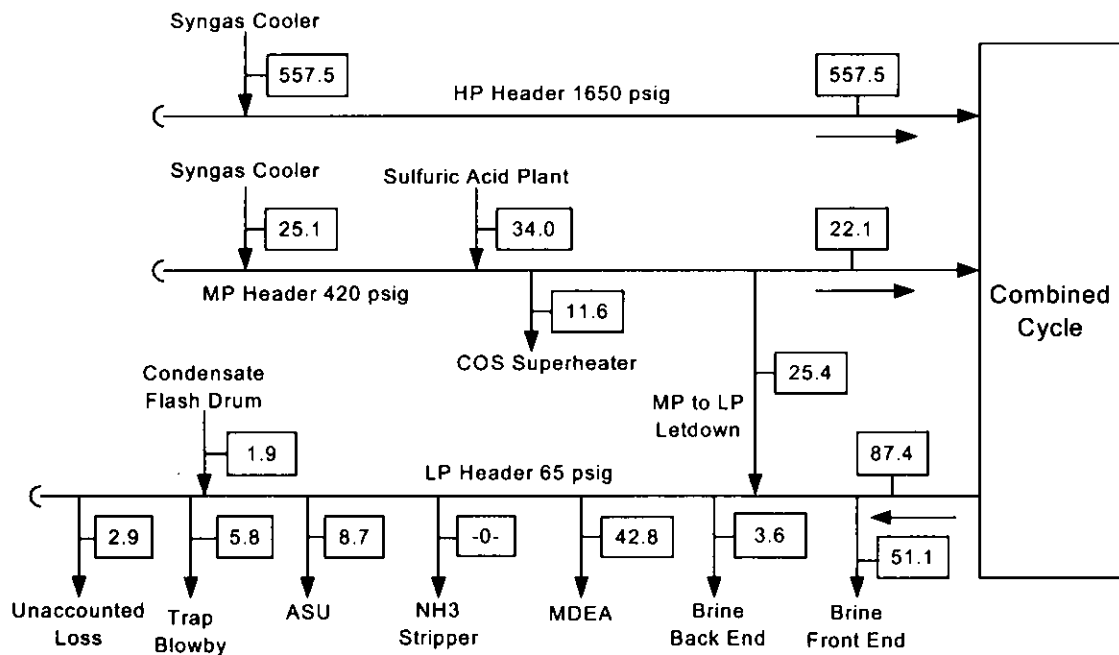
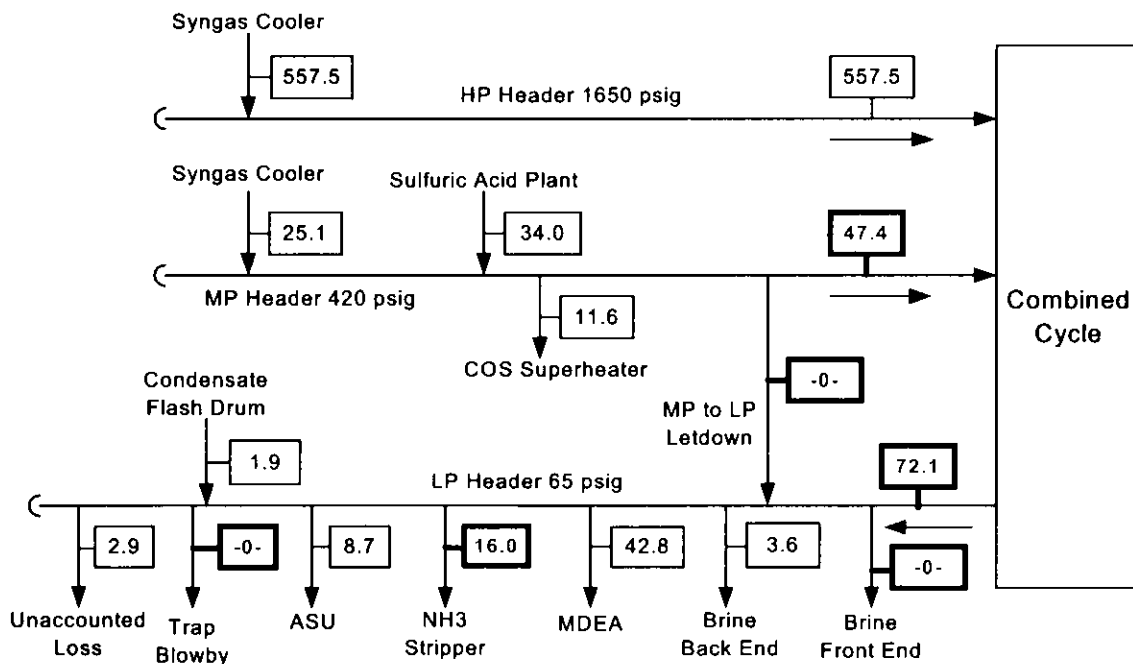


Figure 6-2 Actual Process Plant Steam Distribution



Legend: x x = Steam Flow (KPPH) x . x = Adjusted Steam Flow (KPPH)

Figure 6-3 Adjusted Process Plant Steam Distribution

6.2 Factors Which Change Efficiency

Process Plant Steam Distribution

Note 8 in Section 6.1 identified steam distribution changes which influenced net power production and efficiency. A detailed steam cycle model quantified the value of steam consumed or produced in the process plant. The results of that analysis are shown in Table 6-2. These values were verified during plant operation to the extent possible.

	Value/Cost To Steam Cycle of Saturated Steam Produced or Consumed in the Process Plant (kWh/10,000 Lb Steam)	
	Produced In Process Plant	Consumed by Process Plant
HP (1650 psig)	740	790
MP (420 psig)	680	660
LP (50 psig)	600	600

Table 6-2 Power Value/Cost of Steam

These factors can be used to quickly determine the impact of changes in the plant configuration or in certain coal properties. For example, increases in the coal's sulfur content would require proportionately more MDEA circulation, which in turn would require proportionately more LP stripping steam to the MDEA reboiler. This increase in LP steam consumption in MDEA would be partially offset by more MP steam produced in the Sulfuric Acid Plant. Table 6-2 can be used to estimate the change in net plant power output resulting from these steam flow changes.

Ambient Temperature

The period from early December 1997 to mid January 1999 provided a good deal of useful data for developing empirical correlations for several reasons:

- Much of the time was spent on the same coal (Consol Kentucky 11),
- The mass spectrometer had high availability during the period so the syngas composition was known, and
- The plant operated over a wide range of ambient temperatures and loads.

Figure 6-4 shows the weak correlation which exists between ambient temperature and net heat rate at normal full load conditions. Heat rate is steady down to about 70° F, about where the CT compressor guide vanes are closed. Once the CT guide vanes are closed, the turbine exhaust temperature falls as ambient temperature continues to drop, causing overall cycle efficiency to deteriorate slightly.

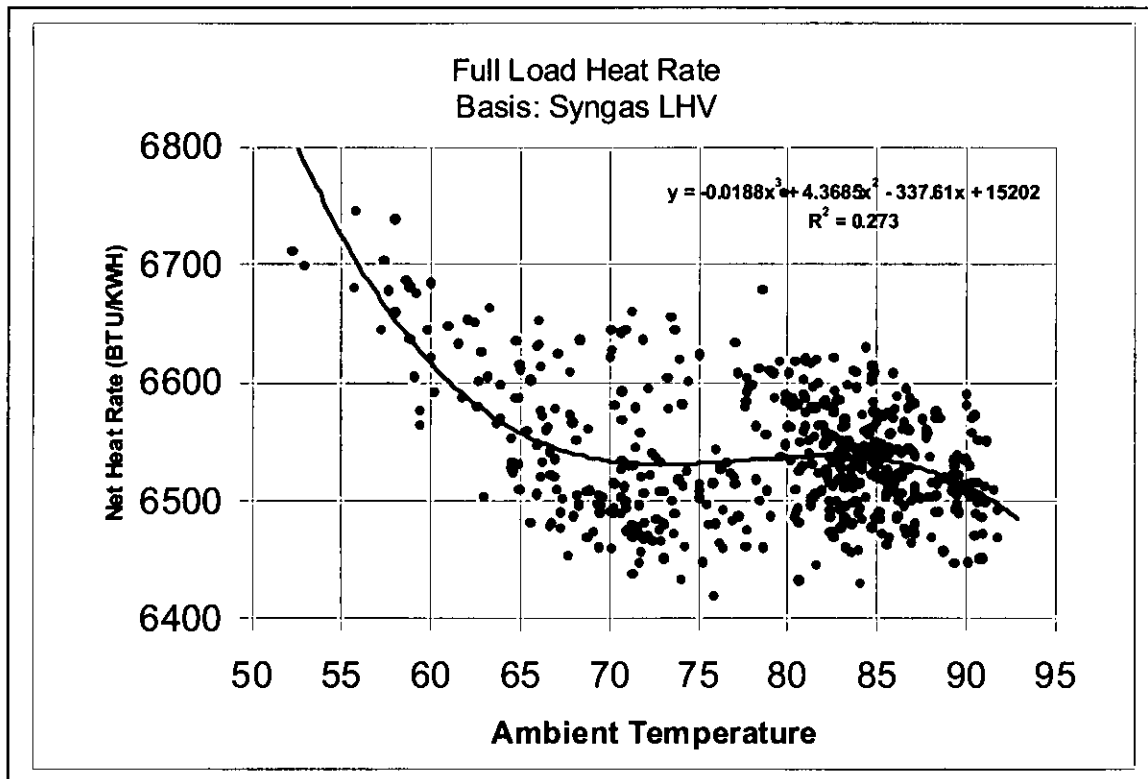


Figure 6-4 Full Load Heat Rate vs Ambient Temperature

Diluent Nitrogen

It is not unusual for useful (or at least interesting) information to arise from a malfunction. The CT's control algorithms adjust the ratio of diluent nitrogen to syngas based partially on the relative humidity of the ambient air. The relative humidity meter failed and could not be repaired for a period of about 3 weeks in August / September 1998. As a result, the controls delivered about 580 KSCFH (10%) less DGAN to the CT than normal. Figure 6-5 shows that there is a noticeable decline in CT efficiency (increase in heat rate) with less DGAN. This is as expected. Without the DGAN, the CT air compressor must supply more air to control the firing temperature. In so doing, the compressor consumes additional energy equivalent to 12.5 MMBTU/Hr of syngas LHV:

$$\begin{aligned}
 (8615-8550) &= 65 \text{ BTU/kWh at } 80^\circ \text{ F (Figure 6-5)} \\
 &\times 192,000 \text{ kWh} \\
 &\times \frac{1 \text{ MMBTU}}{1,000,000 \text{ BTU}} \\
 &= 12.5 \text{ MMBTU/Hr}
 \end{aligned}$$

This makes each SCF of DGAN worth about 21.5 BTU of syngas LHV to the CT. At an overall cycle heat rate based on syngas LHV of 6550 BTU/kWh (Figure 6-4 above), this makes each KSCFH of DGAN worth 3.28 kWh to the cycle. This isn't completely free, though. The DGAN compressor consumes 1.44 kWh/KSCFH of DGAN which partially offsets the advantage. But the DGAN would still have a positive value of 1.84

kWh/KSCF injected. This is only true if DGAN is available at the DGAN compressor's normal suction pressure, i.e., it is not attractive if the MAC throughput has to be increased to produce additional DGAN. Furthermore, it is only true while the CT compressor inlet guide vanes have room to back off, and as long as the combined syngas mixed with the DGAN has a high enough heating value to produce a stable flame in the CT combustors. Finally, the steam cycle will suffer incrementally, perhaps as much as 1 kWh/KSCF of DGAN, due to the reduced syngas flow and associated reduction in SGC steam production. A similar analysis would indicate that syngas saturation is more efficient than DGAN injection up to the limit of availability of low level heat to humidify the syngas. This information will be factored into the design of the additional NO_x abatement required at Polk by mid-2003.

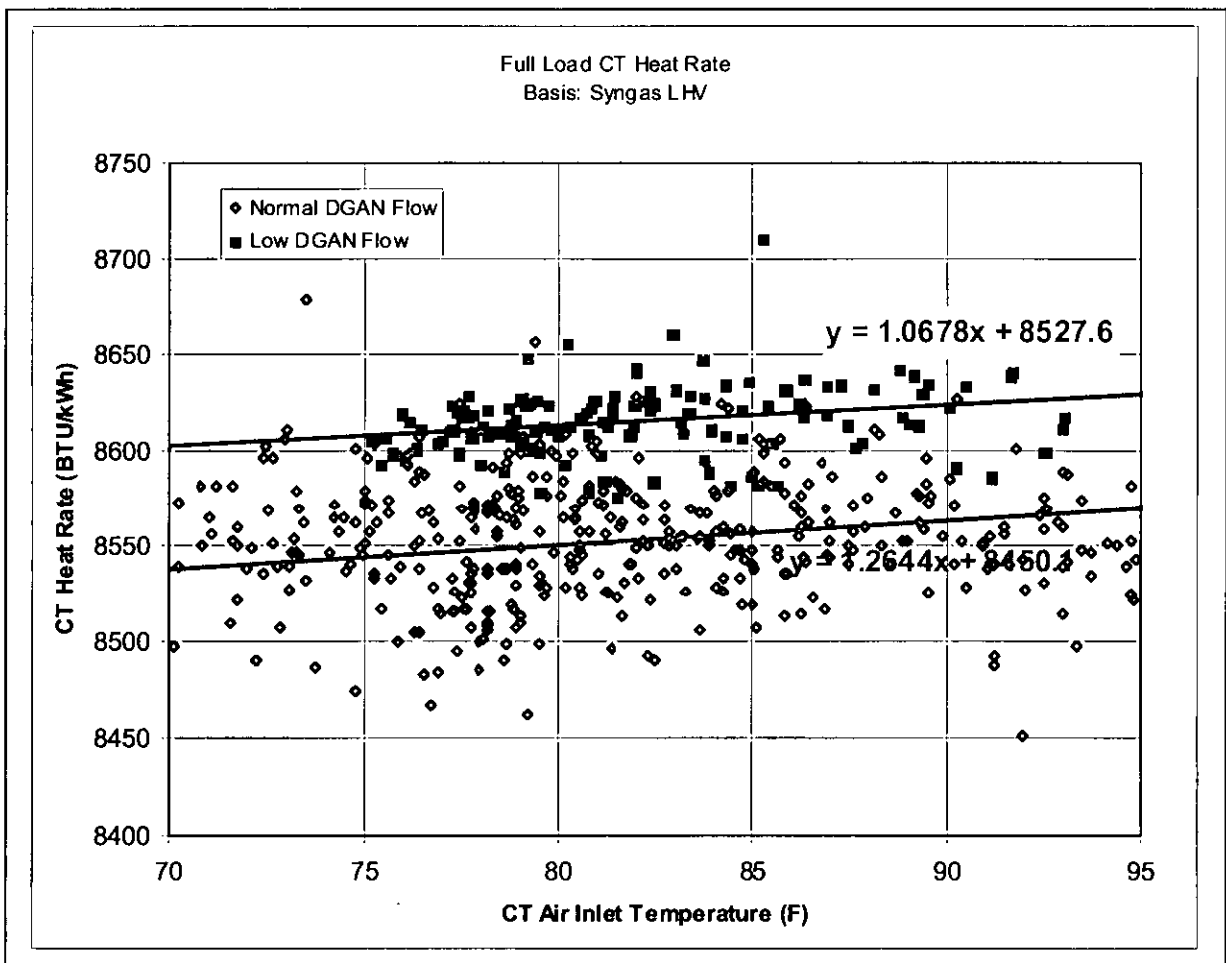


Figure 6-5 CT Heat Rate and DGAN Injection

Load

Figure 6-6 shows how the plant net heat rate based on syngas LHV to the CT varies with CT load. Only the data above 70° F was used to avoid the need to make any significant compensation for differences in ambient temperature, and the data with low DGAN flow to the CT has been excluded. Otherwise, it is based on the same data as the previous figures 6-4 and 6-5

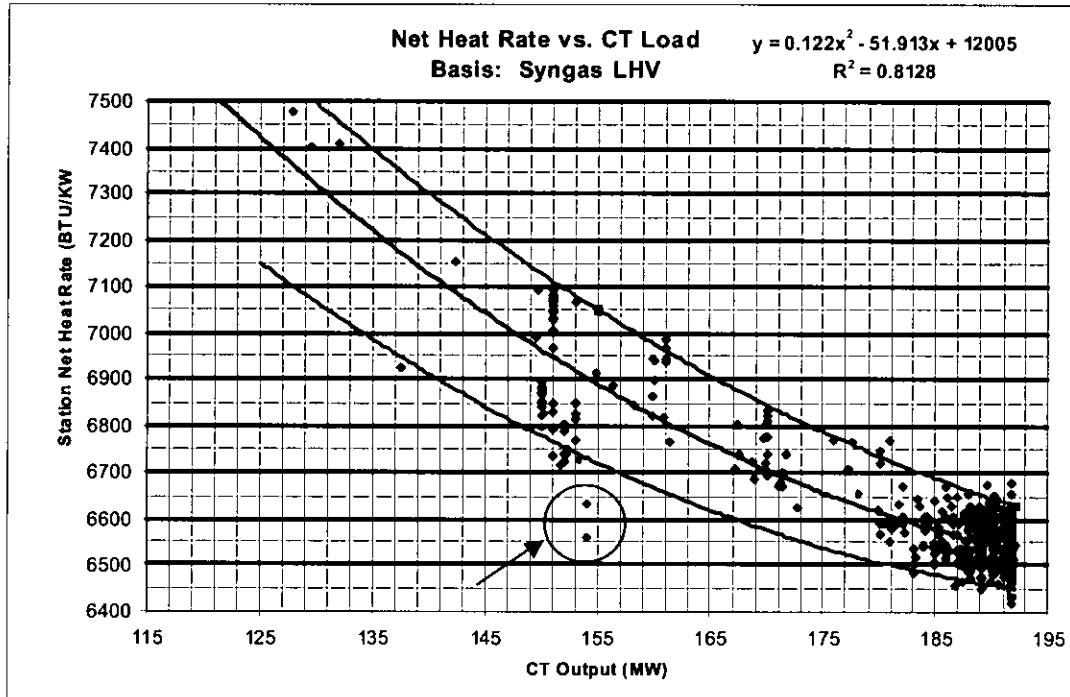


Figure 6-6 Heat Rate vs. CT Load

The full load data are almost all contained within a 2.7% band (6450 to 6625 BTU/kWh). This band is remarkably narrow considering the potential for variation. The "Typical" case presented in Figure 6-1 and Table 6-1 (192 MW, 6480 BTU/kWh) is in the higher efficiency part of the range since inefficiencies due to known steam leaks have been factored out. That case otherwise reflects normal full load operation.

As expected, the heat rate increases at lower loads, consistent with the typical performance profile of a combined cycle. The range (scatter) of the data also expands at lower loads, reflecting some of the vagaries of turndown operation. In most cases, explanations for the variations can be identified with patient searching. For example, the two encircled data points with relatively low heat rate at 154 MW were generated when neither the brine concentration system nor the ammonia stripper were operating. Operation of both these units result in higher heat rate. Also, as will be seen in the next section, some of the variation in the Figure 6-6 data, especially that at reduced CT loads, is attributable to differences between coals.

Differences Between Coals – Impact on Power Block

Figure 6-7 below presents the same data as the previous Figure 6-6 used to illustrate the influence of load on heat rate. However, now the different coals which were the source of the syngas are identified on the figure, making it clear that some coals perform better than others. Ohio 11, the base coal during the period, exhibited about average full load heat rate, but it did better than the other coals at reduced load. The two Pittsburgh #8 seam coals, Humphries and Bell, seemed to perform very much according to the average regression line for all the data, with a slight deviation toward lower efficiency at the very low loads. Wildcat seemed to do slightly better than average, while the other Illinois #6 seam coal, Zeigler, seemed to do slightly worse.

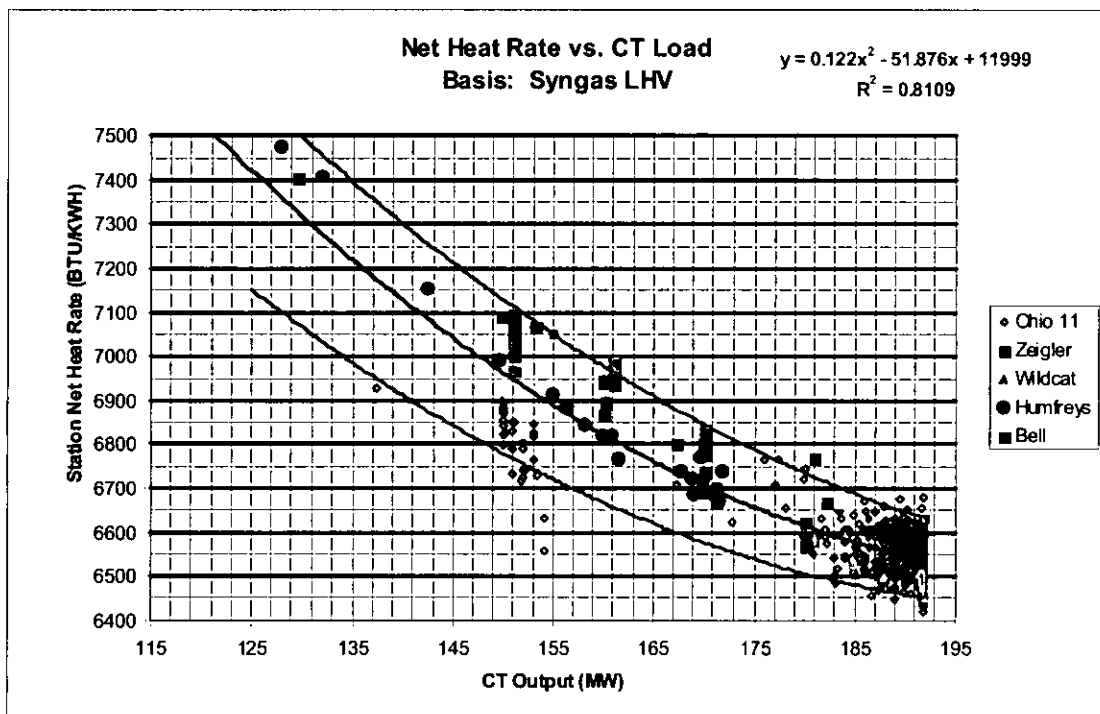


Figure 6-7 Effect of Coal Type and CT Load on Efficiency

Another important aspect of overall performance is net output. Figure 6-8 is the important companion to the above Figure 6-7 which shows the ratio of net station output to CT output for the various coals. The same data set was used to generate both figures. The ratio of net output to CT output is relatively constant, but the regression line does show a slight decline at lower load, reflecting the expected inefficiencies of turn-down on other parts of the plant besides the CT. The one exception is the base fuel, Ohio 11, which has a slightly higher ratio at lower CT loads. This could perhaps be due to an improvement in syngas cooler specific steam production at lower throughput for this one fuel which overrides the other inefficiencies of turndown.

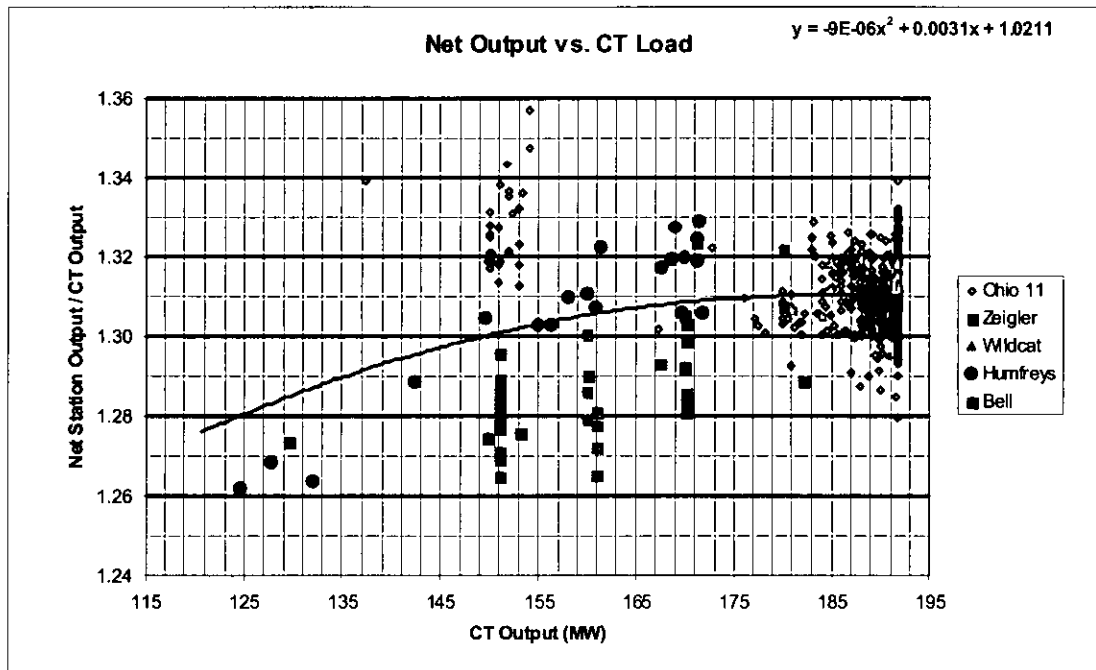


Figure 6-8 Effect of Coal Type on Net Output

Gasifier Efficiency

The final very important aspect of IGCC efficiency is that of the gasifier itself in the context of the combined cycle. Most of the combined cycle's energy is provided by the lower heating value of the syngas fuel. Previous sections of this chapter have discussed how the combined cycle's output varies with syngas fuel LHV as ambient temperature, load, diluent nitrogen rate, and coal source vary. That information is relatively easy to generate since it is based on data gathered with on-line instruments and continuous analyzers. However, an IGCC is, by definition, a solid fuel fired power plant, so the overall efficiency must ultimately be related to the heating value of its solid fuel. Sampling and measurement of the important properties of solid fuel streams is much more difficult. For this information, we must again turn to the results of the heat and material balance periods discussed in Chapter 5. The specific information we need is the relationship between the solid fuel high heating value (HHV) and the syngas lower heating value (LHV). One form of that relationship is illustrated in Figure 6-9 for the Pittsburgh #8 coals and in Figure 6-10 for the Illinois Basin coals tested at Polk. We expect higher efficiency at higher slurry concentration since burning coal or syngas to evaporate extra slurry water cannot be efficient. Consequently, gasifier efficiency (gas LHV / coal HHV) is plotted in the figures versus slurry concentration. However, a direct plot of these parameters shows an almost random pattern. An important reason for the scatter is the widely varying carbon conversion between the cases. Unconverted carbon cannot contribute to the gas heating value. The scatter is significantly reduced if we divide the efficiency by the overall carbon conversion. This enables us to evaluate

the efficiency based on the carbon which actually participates in the gasification reactions. Conversion information on the various fuels is presented in Chapter 5. Although significant scatter still remains, the graphs do show the expected trend of increasing efficiency with increasing slurry concentration.

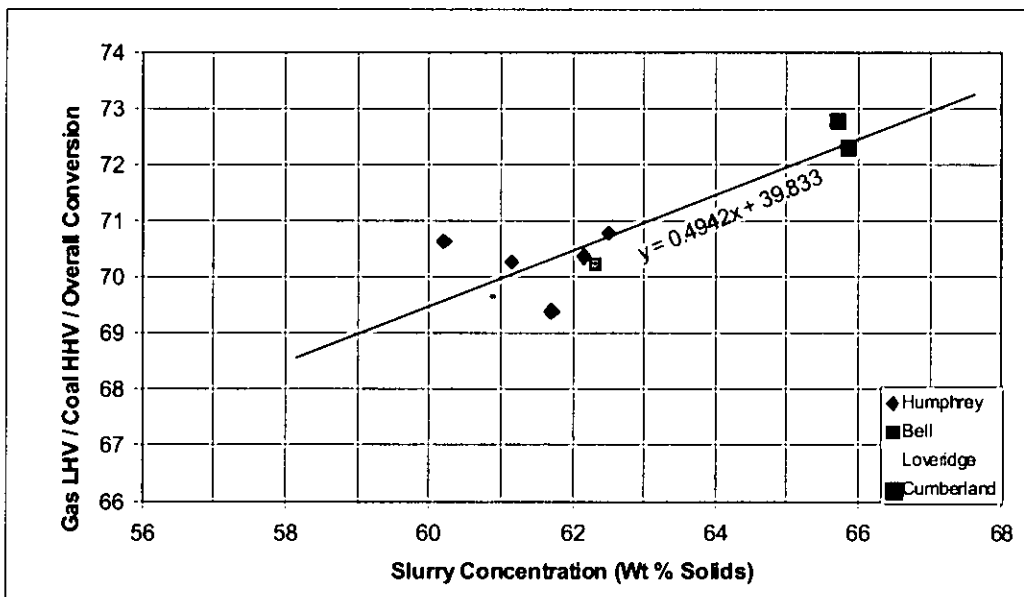


Figure 6-9 Gasifier Efficiency – Pittsburgh #8 Coals

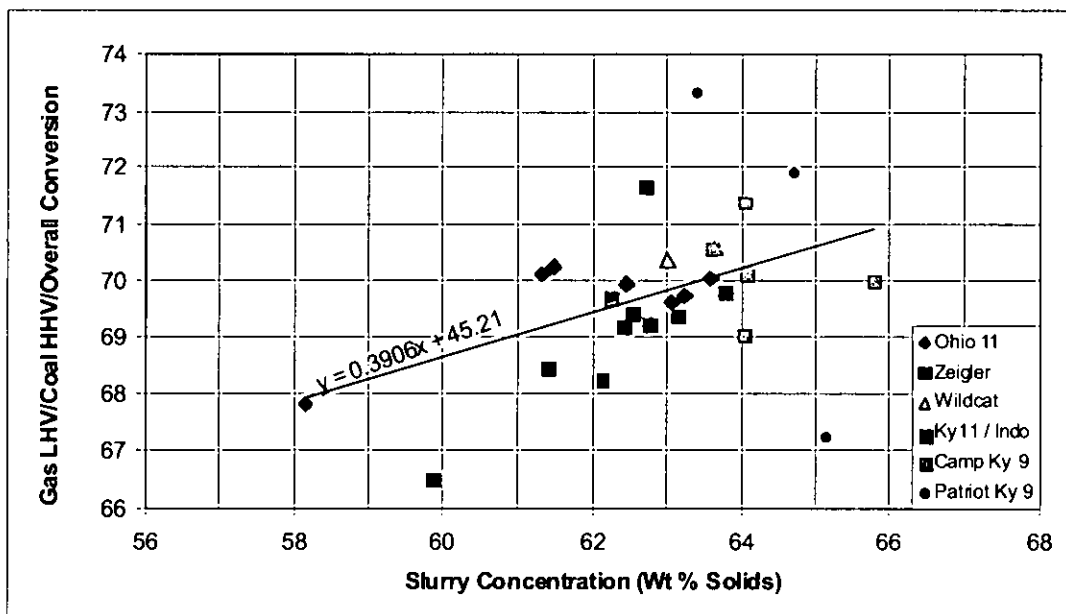


Figure 6-10 Gasifier Efficiency – Illinois Basin Coals

6.3 Mass Balance

Figure 6-11 is a block flow diagram of the process plant with numbered input, output, and key internal streams. Table 6-3 on the same page shows the total flow rates of these numbered streams, and Table 6-4 shows their compositions and elemental balances for C, H, O, N, S, and ash. This material balance is associated with the energy balance discussed in Section 6.1, and is based on full load operation with Patriot Kentucky #9 coal in November, 1999. Comparable material balance information from part load operation with a petroleum coke blend and a small percentage of biomass fuel can be found in Appendix G.

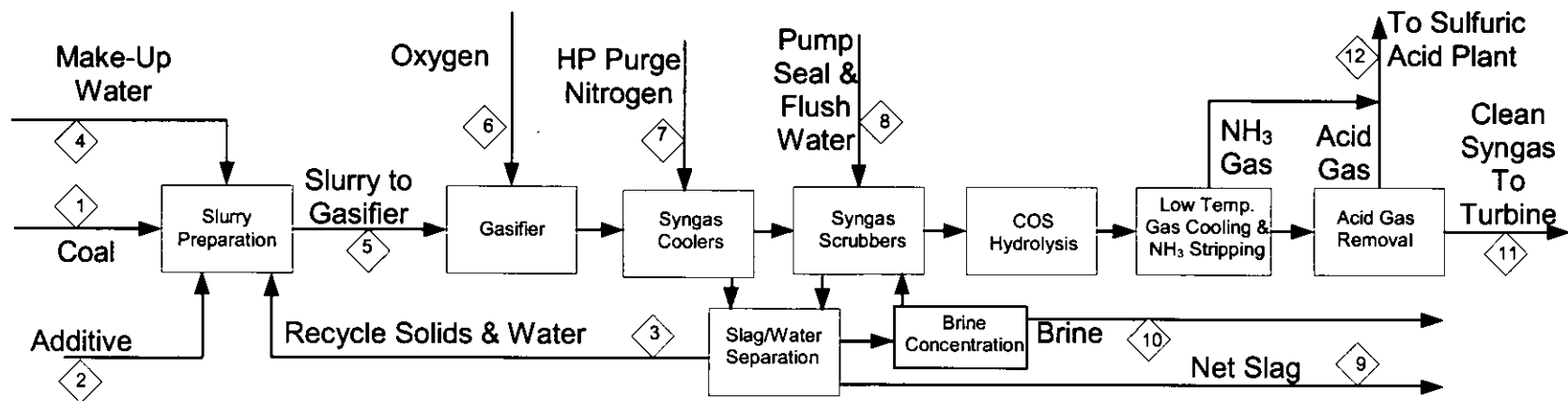


Figure 6-11 Process Plant Mass Balance Block Diagram

Input (Feed) Streams			Product (Output) Streams		
Stream Number	Stream Description	Flow (KPPH)	Stream Number	Stream Description	Flow (KPPH)
1	Coal	213.6	9	Slag	34.1
2	Additive	0.0	10	Brine	0.6
4	Make-Up Water To Slurry	16.8	11	Clean Syngas To Combustion Turbine	375.6
6	Oxygen To Gasifier	178.8	12	Acid and NH ₃ Gas To Sulfuric Acid Plant	27.7
7	High Pressure Purge/Sootblowing N ₂	13.6	TOTAL SYSTEM OUTPUT STREAMS		
8	Pump Seal/Instrument Flush Water	15.2			438.0
TOTAL SYSTEM INPUT STREAMS		438.0	Key Internal Streams		
			5	Slurry To Gasifier	307.6
			3	Recycle Solids/Water To Slurry Prep.	77.2

Table 6-3 Overall Mass Balance

STREAM NO.	GASIFICATION SYSTEM INPUTS							GASIFICATION SYSTEM OUTPUTS					INTERNAL STREAMS	
	1	2	4	8	6	7		11	12	9	10		5	3
UNITS	COAL	ADDITIVE	SLURRY MAKE-UP WATER	SEAL & FLUSH WATER	OXYGEN	HP PURGE N2	TOTAL SYSTEM INPUT	CLEAN SYNGAS	ACID GASES	NET SLAG	BRINE (NH4Cl)	TOTAL SYSTEM OUTPUT	SLURRY TO GASIFIER	RECYCLE TO SLURRY PREP
GAS STREAM COMPOSITIONS														
CO	VOL %							42.39	0.33					
H2	VOL %							37.27	0.57					
CH4	VOL %							0.07	0.02					
CO2	VOL %							15.45	68.36					
N2	VOL %				1.43	99.99		3.63	0.05					
Ar	VOL %				2.66	0.00		0.82	0.00					
H2O	VOL %							0.33	3.57					
H2S	VOL %							0.02	23.58					
COS	VOL %							0.01	0.07					
NH3	VOL %							0.00	3.45					
O2	VOL %				95.90	0.01		0.00	0.00					
TOTAL	VOL %				100.00	100.00		100.00	100.00					
MOLECULAR WT	LB/MOLE				32.12	28.02		20.85	39.51					
FLOW	KSCFH				2113	184		6837	266					
SOLID & LIQUID STREAM COMPOSITIONS														
C	WT %	71.78	42.02							22.57	0.00		70.56	36.48
H	WT %	4.84	4.39							0.12	7.49		4.68	0.36
N	WT %	1.56	2.99							0.24	26.22		1.54	0.98
S	WT %	3.04	5.99							1.11	0.00		3.01	2.15
O	WT %	9.15	40.12							0.00	0.00		8.83	0.00
ASH + Cl	WT %	9.63	4.49							75.96	66.29		11.38	60.04
TOTAL DRY SOLIDS	WT %	100.00	100.00							100.00	100.00		100.00	100.00
DRY SOLIDS FLOW	KPPH	190.1	0.0							23.9	0.3		197.0	6.8
H2O	WT %	11.00	50.00	100.00	100.00					30.00	50.00		35.97	91.14
H2O FLOW	KPPH	23.5	0.0	16.8	15.2					10.2	0.3		110.7	70.4
TOTAL FLOW	KPPH	213.6	0.0	16.8	15.2					34.1	0.6		307.6	77.2
ELEMENTAL FLOWS / BALANCE:-														
C	LB/HR	136481	0				136481	125307	5791	5383	0	136481	138976	2495
H	LB/HR	11827	0	1876	1698		15401	13710	465	1172	54	15402	21604	7901
N	LB/HR	2966	0			2235	13567	18768	347	57	75	18773	3033	67
S	LB/HR	5782	0				5782	206	5316	265	0	5786	5929	147
O	LB/HR	38267	0	14888	13474	170683	1	237314	212203	15780	9078	255	237315	115667
ASH + Cl	LB/HR	18309	0					18309	0	18116	190	18307	22416	4107
Ar	LB/HR	0	0			5919	0	5919	5921	0	0	5921	0	0
TOTAL	LB/HR	213632	0	16764	15172	178837	13568	437974	375640	27699	34071	574	437984	307625

Table 6-4 Stream Compositions and Elemental Balances

CHAPTER 7 - SYNGAS AND BYPRODUCT COMPOSITION

Polk Power Station's product is electricity whose composition is pondered by physicists. However, Polk does have a key intermediate product (clean syngas) and some byproducts (slag, sulfuric acid, and brine) whose composition warrants discussion. Material Safety Data Sheets (MSDS) for the byproducts are provided in Appendix H.

7.1 Clean Syngas

The composition of clean syngas is given in Table 7-1. The syngas from coal data is from 7 coals operating with 3 different burners. There is relatively little variation in the syngas produced from the coals as evidenced by the low standard deviations. The syngas composition data from petroleum coke blends also has a low standard deviation; hence that syngas is also quite consistent. However, the difference between the average composition of syngas from coal and syngas from petroleum coke is statistically significant.

Component	Units	Coal			Petroleum Coke Blends		
		Mean	Median	Standard Deviation	Mean	Median	Standard Deviation
H ₂ S+CO ₂	PPMV	415	404	62	282	319	105
CH ₄	PPMV	532	468	281	244	214	94
CO	Vol %	44.06	44.07	0.97	48.29	49.16	2.21
CO ₂	Vol %	14.73	14.45	0.93	13.61	13.23	1.17
H ₂	Vol %	37.95	38.01	1.06	34.02	33.72	1.48
N ₂	Vol %	2.28	2.32	0.33	3.02	3.00	0.24
Ar	Vol %	0.88	0.88	0.13	1.00	1.01	0.08
Total	Vol %	100.00			100.00		
HHV	(BTU/SCF)	263.2	264.2	3.5	264.0	264.5	3.6
LHV	(BTU/SCF)	244.3	245.0	3.2	247.0	247.7	3.9

Table 7-1 Syngas Composition

7.2 Slag

"Slag" has two constituents:

- Coarse glassy frit containing relatively little carbon
- Smaller char particles containing most of the gasifier's unconverted carbon.

There are several important aspects of the slag's composition.

- 1) Ash mineral analysis. The slag's ash mineral analysis almost exactly mirrors that of the feed fuel with the following exceptions.
 - a. The fuel's chloride, usually considered as part of its ash, is converted to HCl in the gasifier and goes to the process water instead of to the slag.

- b. The ultimate fate of a significant fraction of the fuel's mercury and smaller fractions of a few other volatile trace elements such as arsenic is elusive.
- c. Chromium from the gasifier's refractory liner is found in the frit. The chromium content of the frit is between 100 and 1500 ppm higher than that of the feed fuel's ash. We try to minimize the amount of chromium picked up by the frit since less chromium in the frit reflects lower refractory wear rate. Testing has verified that the chromium is not in the form of potentially hazardous Chromium VI.

2) Loss On Ignition, Heating Value

Loss on Ignition (LOI) is the sum of the non-ash constituents of the slag (C, H, O, N, and S). A low LOI value is required for virtually all non-fuel end uses of slag such as for cement and blasting grit. The glassy frit is generally suitable for such applications after most of the char is removed. On the other hand, the char has a higher LOI value. Higher LOI is directly related to higher heat content (HHV) which makes the char more suitable for recycling to the gasifier or burning elsewhere. Table 7-2 shows the average ultimate analyses and heating value of slag from Kentucky and Pittsburgh seam coals and from petroleum coke blends. Separate analyses are provided for the char portion and for the frit as well as for the overall (mixed) slag.

3) Contaminants in surface moisture (chloride and ammonia)

If no special effort is made to dry or dewater the slag, it will retain approximately 30% (wt) surface moisture. In Polk's original configuration, this moisture consisted of grey or black water containing up to 3500 ppm (wt) chloride and approximately an equal amount of ammonia. These made the frit unsuitable for end-use applications. The chloride is corrosive in end products such as cement, and the ammonia content was high enough that the odor was objectionable to potential users. Consequently, Polk was reconfigured so only stripped process condensate now contacts the frit. See Section 1.3.5.6.1, Items 5 and 6. Process condensate contains virtually no chloride and stripping reduces its ammonia content to less than 500 ppm so the ammonia odor is barely detectable in the slag. This reconfiguration reduced the concentration of contaminants by over an order of magnitude, making the frit suitable for some end uses.

Slag composition is more variable than that of syngas as can be seen from the ultimate analyses provided in Table 7-2. The table indicates that when the fuel is coal, the ultimate analysis of each of the two constituents of slag, the frit and the char, is relatively constant from coal to coal. Note the low standard deviation for the composition constituents of char and slag from the Kentucky and Pittsburgh coals. As net carbon conversion changes with changes in fines recycle or operating temperature, the ratio of frit to char simply adjusts accordingly. However, for petroleum coke, the composition of the char and of the frit changes with the changes in overall conversion resulting from different settler bottoms recycle rates. The current practice is to recycle as much of the char as we can recover, so the resulting frit would be suitable for end-use applications once the char is removed.

FUEL	Kentucky #9 & #11		Pittsburgh #8		Petroleum Coke Blends		
	Average	Std Deviation or Range	Average	Std Deviation or Range	Average	Average	Average
RECYCLE CONDITIONS							
Recycle % of Settler Bottoms	33%	0-100%	63%	53%-74%	100%	45%	0%
Recycle % of Total Char Produced	22%	0% - 64%	48%	42%-54%	72%	33%	0%
SLAG CONSTITUENTS							
% of Frit in Net Slag	32%	24%-49%	36%	29%-43%	35.98	7.47	2.36
Frit Ultimate Analysis							
%C	2.82	0.29	4.23	0.21	2.22	13.50	34.47
%H	0.04	0.01	0.02	0.00	0.00	0.03	0.07
%N	0.04	0.01	0.05	0.00	0.02	0.13	0.35
%S	0.20	0.06	0.16	0.01	0.07	0.41	1.02
%Ash	96.90	0.36	95.54	0.23	97.68	85.93	64.09
Char Ultimate Analysis							
%C	37.60	0.22	43.87	0.40	71.87	77.09	84.19
%H	0.46	0.07	0.26	0.01	0.10	0.19	0.14
%N	0.48	0.06	0.51	0.01	0.67	0.75	0.86
%S	2.94	0.67	1.81	0.04	2.40	2.35	2.62
%Ash	58.52	0.78	53.55	0.36	24.96	19.62	12.19
Char Heating Value (HHV)							
BTU/Lb - Dry Basis	5451	72	6253	57	10464	11310	12374
OVERALL (NET) SLAG							
Average Quantity							
Lb Dry Net Slag/Net MWH	81		78		58	121	195
Lb Dry Net Slag/Lb Dry Fuel	0.109		0.116		0.085	0.169	0.256
Ultimate Analysis							
%C	26.13	1.15	29.51	3.94	46.81	72.34	83.02
%H	0.32	0.03	0.17	0.03	0.07	0.18	0.14
%N	0.33	0.03	0.34	0.04	0.44	0.70	0.85
%S	2.02	0.40	1.21	0.20	1.56	2.21	2.58
%Ash	71.19	0.84	68.76	4.21	51.13	24.57	13.41
Heating Value (HHV)							
BTU/Lb Dry Basis	3587	149	3990	625	6585	10573	12193

Table 7-2 Slag Composition

7.3 Sulfuric Acid

The sulfuric acid produced at Polk averages 98.3% assay, i.e., 98.3% (wt) H₂SO₄ and 1.7% (wt) H₂O. Typical contaminants are 12 ppm iron and 20 ppm of substances reducing KMnO₄ (predominantly SO₂ and some NO_x). The Polk acid is well suited for use in the local fertilizer industry. However, that market does experience periods of weakness, so equipment to produce an acid for water treatment is being commissioned. Those specifications require slightly weaker acid (93%) with lower SO₂.

7.4 Brine

The brine concentration unit produces a salt with a typical analysis of 64.1 % (wt) Cl and 32.4 % (wt) NH₄ with 3.5 % moisture. It normally leaves the process as a dry white solid cake, but sometimes with a grey tint due to minor contamination with coal fines from the process water. Even when it is snow white as it leaves the process, it tends to discolor as it absorbs moisture from the atmosphere. The chloride in the brine represents almost all of the chloride in the feed coal.

CHAPTER 8 - OUTLOOK

The IGCC demonstration project at Polk Power Station has attracted a great deal of attention from industry, government and academia. Since its inception, the plant has hosted over 2500 visitors from over 20 countries (Appendix F). The reason for the interest in the project is varied, but typically focuses on the technology used, environmental performance, system reliability and capital cost.

Many of our visitors are in the process of evaluating IGCC as an option for generation expansion. Their interest stems from the advantage of using coal (or other solid feedstocks) as a secure, low cost, fuel for power generation. The IGCC process allows the use of coal in an environmentally acceptable manner.

Visitors to the site leave with their own opinions as to the pros and cons of the process. Typical conclusions as to the benefits of IGCC include:

- Polk has demonstrated the flexibility of using a number of different solid fuels including over 15 coal types, petroleum coke and biomass. This is seen as a major advantage over natural gas from a price, volatility and security of supply standpoint.
- Polk has demonstrated superior environmental performance regarding SO₂, NO_x and particulate matter versus other coal technologies.
- IGCC is well suited for mercury and CO₂ removal if and when these constituents become regulated.
- Polk has demonstrated the use of IGCC in a commercial size for power generation.
- IGCC generally has a higher cycle efficiency than other coal fired technologies.

The typical concerns expressed by our visitors regarding their adoption of IGCC technology include:

- IGCC has a high level of capital investment required versus NGCC plants. The capital costs of the Polk project are discussed in detail within this report. There is general agreement that capital costs will be lower for the next generation of IGCC, but the uncertainties of returns in future power markets have made it difficult for potential users to select the high capital cost option.
- IGCC has a lower equipment availability than NGCC and perhaps other coal fired technologies. Polk's equipment availability is discussed in detail within this report. As a demonstration plant, Polk's availability has been lower than the next generation plant would be. Based on the lessons learned here and at other demonstration plants, the next IGCC plants will incorporate improvements in equipment/material selection, operating procedures and level of redundancy. An important point, that is undervalued by many visitors, is that the overall availability of the plant, including operation on backup fuel in conventional combined cycle mode, is very high. Where a natural gas supply exists, a future IGCC plant might be considered as a high availability NGCC plant with a

moderate availability gasifier on the front end. Gasifier availability could be engineered to be as high as the particular project economics dictate.

- Operation of an IGCC plant requires different technical skills than those with which power generating utilities are generally familiar. The Polk project has demonstrated that a modest size utility, with expertise in coal fired generation, can build and operate an IGCC plant. Tampa Electric paid careful attention to personnel selection and training to make this project a success.
- Existing IGCC plants have been engineered and constructed as an assembly of individual process units. The process unit suppliers will offer performance guarantees at their boundary limits, but no guarantee is typically available for the overall IGCC plant. The assumption of the overall plant performance risk has made financing and ultimately the selection of IGCC technology more difficult.

A common sentiment expressed by visitors from other electric utilities is that they would like to see someone else take the risk in building the next IGCC plant. The "risk" being quoted seems about equally split between a perceived availability risk and an economic risk. We believe that the demonstration plants, including Polk, have shown that the availability issue can be effectively managed, particularly in the next generation of plants. The economic risk is a bit more complicated. The higher initial costs for IGCC can be offset by long term fuel savings, (depending, of course, on the fuel forecast in use). In the last few years, a litany of external factors such as deregulation, power market pricing, California, ENRON and most recently stock devaluation have impacted the risk tolerance of potential users. At this point, it seems everyone "wants the other guy to go first" when it comes to IGCC.

The Department of Energy has been, and continues to be, very supportive of IGCC process. In their "Vision 21" program, the DOE lists IGCC as a key core technology. Vision 21 describes a 21st century energy plant that eliminates the environmental issues associated with the use of fossil fuels and provides energy efficiency through production of electric power, heat, chemicals and fuel gases. The DOE projects these plants to be in service by 2015.

The path from the current situation of unwillingness to accept the perceived risks of an IGCC plant, to the widespread use envisioned by the DOE, is unclear. A number of factors could tip the risk vs. reward scale in favor of IGCC for the next plants to be built. These include:

- Another round of governmental co-funding of IGCC through CCT, or other program.
- A lasting change in the expected availability or price differential of natural gas to coal.
- Environmental legislation requiring mercury and or CO₂ removal.
- Economic stability that allows potential users to take a longer term investment view.

The outlook for IGCC is good. The technology needs one or two more successful projects for widespread use to take place.

APPENDIX A - COALS AND OUTAGE CAUSES

1996 Polk IGCC Fuels and Shutdown Causes

Sun Mon Tu Wed Thu Fri Sat

					07/20	07/21	Excess Fines
07/22	07/23	07/24	07/25	07/26	07/27	07/28	
07/29	07/30	07/31	08/01	08/02	08/03	08/04	
08/05		08/07	08/08	08/09	08/10	08/11	ST Condensate Pumps
08/12	08/13		08/15	08/16	08/17	08/18	Geho Flush Procedure
08/19	08/20	08/21	08/22	08/23	08/24		
08/26		08/28	08/29				Burner Cooling Logic Error
09/02	09/03	09/04	09/05	09/06	09/07	09/08	Excess Fines
09/09	09/10	09/11		09/13	09/14	09/15	RG/CG Exchanger
09/16	09/17	09/18	09/19	09/20	09/21	09/22	
09/23	09/24	09/25	09/26	09/27	09/28	09/29	STARTUP
09/30		10/02	10/03	10/04	10/05	10/06	COMMERCIAL OPERATION
10/07	10/08	10/09	10/10	10/11			RG/CG Exchanger
			10/17	10/18	10/19	10/20	CT Broken Bolt
10/21	10/22	10/23	10/24	10/25	10/26	10/27	Clean RG/CG & CSC
			10/31	11/01	11/02	11/03	ST Excitation
		11/05	11/07	11/08	11/09	11/10	ST Excitation
	11/12						DCS Maintenance
	11/19	11/20	11/21				Line Voltage
11/25	11/26						Line Voltage, Slurry Erosion
		12/04	12/05	12/06	12/07	12/08	Line Voltage
12/09	12/10	12/11	12/12	12/13	12/14	12/15	Planned Outage
12/16	12/17	12/18	12/19	12/20	12/21		GOX Silencer
12/23							DGAN Surge Controls

FUEL LEGEND:

■ Pittsburgh #8 - Consol Humphreys

1997 Polk IGCC Fuels and Shutdown Causes

Sun	Mon	Tu	Wed	Thu	Fri	Sat		Sun	Mon	Tu	Wed	Thu	Fri	Sat	
								06/30	07/01				07/05	07/06	Geho Trip
								07/07	07/08	07/09	07/10	07/11	07/12	07/13	
								07/14	07/15	07/16					
		01/22	01/23	01/24			GOX Surge Control								
	02/11	02/12	02/13	02/14	02/15	02/16	Excess Fines	08/11	08/12						Geho Trip and Excess Fines
02/17	02/18	02/19					Y Strainer Removal							08/24	Scrubber Circ Water Piping
									08/26	08/27	08/28	08/29	08/30	08/31	RSC Dome Seal Leak
	03/04	03/05	03/06	03/07	03/08	03/09	Nozzle Scrubber; O2 Line	09/01	09/02	09/03	09/04	09/05	09/06	09/07	
03/10	03/11	03/12	03/13			03/16	O2 Line Brittle Rupture	09/08	09/09	09/10	09/11	09/12	09/13	09/14	
03/17	03/18	03/19	03/20	03/21	03/22	03/23	RG/CG Exchanger	09/15	09/16	09/17	09/18	09/19	09/20	09/21	
03/24	03/25	03/26	03/27	03/28	03/29	03/30	CT Damage	09/22	09/23				09/27		Voltage Spike
03/31	04/01	04/02	04/03	04/04	04/05	04/06	Remove 1 RG/CG Shell						10/11	10/12	Nozzle Scrubber Leak
04/07	04/08	04/09	04/10	04/11	04/12	04/13		10/13	10/14						O2 Block Valve Limit Switch
04/14	04/15	04/16	04/17	04/18	04/19	04/20		10/21	10/22	10/23	10/24	10/25	10/26		
04/21	04/22	04/23		04/25	04/26	04/27	RG/CG Exchanger								
04/28	04/29	04/30	05/01	05/02	05/03	05/04	Leak From Last Repair								
05/05	05/06	05/07	05/08	05/09											
								11/10	11/11	11/12			11/15	11/16	Excess Fines
								11/17	11/18	11/19	11/20	11/21	11/22	11/23	RSC Roof Seal Leak
	05/27	05/28	05/29	05/30	05/31	06/01	RG/CG Exchanger	11/24	11/25	11/26	11/27	11/28			
06/02	06/03	06/04	06/05	06/06	06/07	06/08	Turbine Damage-Pipe Scale	12/01	12/02	12/03	12/04	12/05	12/06	12/07	
06/09	06/10	06/11	06/12	06/13	06/14	06/15	Remove Remaining RG/CG	12/08	12/09			12/12	12/13	12/14	
06/16	06/17	06/18	06/19	06/20	06/21	06/22		12/15	12/16	12/17	12/18	12/19	12/20	12/21	
06/23	06/24	06/25	06/26	06/27	06/28	06/29		12/22	12/23	12/24	12/25	12/26	12/27	12/28	
								12/29	12/30	12/31					

FUEL LEGEND:

- Pittsburgh #8 - Consol Humpries
- Pittsburgh #8 - Bell
- Indiana #7 Black Beauty / Pet Coke Blend

- Illinois #6 - Zeigler
- Kentucky #11 - Consol Ohio 11

1998 Polk IGCC Fuels and Shutdown Causes

Sun	Mon	Tu	Wed	Thu	Fri	Sat		Sun	Mon	Tu	Wed	Thu	Fri	Sat		
				01/01	01/02	01/03	Scrubber Leak			07/06	07/07	07/08	07/09		Geho Check Failure	
01/04	01/05	01/06	01/07	01/08	01/09	01/10	RSC Sump Pluggage							07/16	07/17	Clean CSC
01/11	01/12	01/13	01/14	01/15	01/16	01/17	GOX Intercooler Gasket	07/18	07/19	07/20	07/21		07/23	07/24		
01/18	01/19	01/20	01/21		01/23		Acid Gas Flare, Restart Failure	07/25	07/26	07/27	07/28					
		02/17	02/18	02/19	02/20	02/21	SAP Furnace Hot Spot									
02/22	02/23	02/24														
														09/11	Loss of Condenser Cooling	
		03/09	03/10				Power Surge, MAC IGV's	09/12	09/13	09/14	09/15					
												09/29	09/30	10/01	Syngas Leak - Scrubber O'Head	
				04/01	04/02	04/03	Plugged Geho Suction							10/15	10/16	Clean CSC
04/04														10/15	10/16	RSC Lower Waterwall Tube Leak
				04/15	04/16	04/17	1sr Scrubber O'Head Leak	10/17	10/18	10/19	10/20	10/21	10/22	10/23		
								10/24								
								10/31								
04/25	04/26	04/27	04/28	04/29	04/30	05/01	CSC Tube Leak									
05/02	05/03	05/04	05/05	05/06	05/07	05/08	Planned Outage									
05/09	05/10	05/11	05/12	05/13	05/14	05/15		11/14	11/15	11/16	11/17	11/18	11/19	11/20	Leak: Replace Scrubber O'Head Lines	
05/16	05/17	05/18	05/19	05/20	05/21	05/22		11/21	11/22	11/23	11/24	11/25	11/26	11/27	Tie-In High Speed Flare	
05/23	05/24	05/25						11/28	11/29	11/30	12/01	12/02	12/03	12/04	Clean CSC	
								12/05	12/06			12/10	12/11		RSC Sump Pluggage - Fuel	
		06/09	06/10	06/11			Scrubber "B" Nozzle Leak	12/12	12/13	12/14	12/15	12/16	12/17	12/18		
								12/19	12/20	12/21						

FUEL LEGEND:

- Pittsburgh #8 - Consol Loveridge
- Kentucky #11 - Consol Ohio 11
- Kentucky #11 / Powder River Basin Blend

- Illinois #6 - Zeigler
- Illinois #6 - Wildcat

1999 Polk IGCC Fuels and Shutdown Causes

Sun	Mon	Tu	Wed	Thu	Fri	Sat	
		01/05	01/06			01/09	MAC IGV Positioner
						01/16	Clean CSC
01/17	01/18	01/19		01/21	01/22	01/23	RSC Sump Pluggage - Fuel
01/24							
				02/04	02/05	02/06	
02/07	02/08	02/09	02/10	02/11	02/12	02/13	
02/14	02/15	02/16	02/17	02/18	02/19	02/20	Gas Leak, Elbow by Aspirator
02/21	02/22	02/23	02/24	02/25	02/26	02/27	
02/28	02/29	03/01	03/02	03/03	03/04	03/05	
03/06	03/07	03/08	03/09	03/10	03/11	03/12	
03/13	03/14	03/15	03/16	03/17	03/18	03/19	Clean CSC, Test Burner #1
03/20	03/21	03/22	03/23	03/24	03/25	03/26	
03/27	03/28	03/29	03/30	03/31	04/01	04/02	Clean CSC, Test Burner #2
04/03	04/04	04/05	04/06	04/07	04/08	04/09	RSC Sump Pluggage - Fuel
04/10	04/11	04/12	04/13	04/14	04/15	04/16	RSC Sump Pluggage - Fuel
04/17	04/18	04/19	04/20	04/21	04/22	04/23	Planned Outage
04/24	04/25	04/26	04/27	04/28	04/29	04/30	CSC Modifications
05/01	05/02	05/03	05/04	05/05	05/06	05/07	
05/08	05/09	05/10	05/11	05/12	05/13	05/14	
05/15	05/16	05/17	05/18	05/19	05/20	05/21	RSC Sump Pluggage - Fuel
05/22	05/23	05/24	05/25	05/26	05/27	05/28	RSC Sump Pluggage - Fuel
05/29	05/30	05/31	06/01	06/02	06/03	06/04	Planned Outage
06/05	06/06	06/07	06/08	06/09	06/10	06/11	
06/12	06/13	06/14	06/15	06/16	06/17	06/18	Vertical Hot Face Refractory
06/19	06/20	06/21	06/22	06/23	06/24	06/25	CT Combustion Inspection
06/26	06/27	06/28	06/29	06/30	07/01	07/02	
07/03							

Sun	Mon	Tu	Wed	Thu	Fri	Sat	
07/04	07/05	07/06	07/07	07/08	07/09	07/10	
07/11	07/12	07/13	07/14	07/15	07/16	07/17	
07/18	07/19	07/20	07/21	07/22	07/23	07/24	Clean CSC
07/25	07/26	07/27	07/28	07/29	07/30	07/31	Slag Crusher Seal
08/01	08/02	08/03	08/04	08/05	08/06	08/07	
08/08	08/09	08/10	08/11	08/12	08/13	08/14	SGC MP Drum Level, Slag Crusher Seal
08/15	08/16	08/17	08/18	08/19	08/20	08/21	COS Tie-in
08/22	08/23	08/24	08/25	08/26	08/27	08/28	Clean CSC, Replace Slag Crusher Seal
08/29	08/30	08/31	09/01	09/02	09/03	09/04	
09/05	09/06	09/07	09/08	09/09	09/10	09/11	
09/12	09/13						
	10/04	10/05	10/06	10/07	10/08	10/09	Cooling Water Leak Into MDEA
	10/10						Clean CSC, CT Start Failure
		10/19	10/20	10/21	10/22	10/23	
10/24	10/25	10/26	10/27	10/28	10/29	10/30	
10/31	11/01	11/02	11/03	11/04	11/05	11/06	Burner Leak, CT Restart Failure
11/07	11/08	11/09	11/10	11/11	11/12	11/13	
11/14	11/15	11/16	11/17	11/18	11/19	11/20	
11/21	11/22	11/23	11/24	11/25	11/26	11/27	
11/28	11/29	11/30	12/01	12/02	12/03	12/04	
12/05	12/06	12/07	12/08	12/09	12/10	12/11	
12/12	12/13	12/14	12/15	12/16	12/17	12/18	Planned CT Stack Test, Clean CSC
12/19	12/20	12/21	12/22	12/23	12/24	12/25	
12/26	12/27	12/28	12/29	12/30	12/31		

FUEL LEGEND:

3/1 Kentucky #11 / Indonesian Blend
 4/1 Kentucky #11 / Indonesian Blend
 Kentucky #11 / Powder River Basin Blend

Kentucky #9 - Peabody Camp
 Kentucky #11 - Consol Ohio 11
 4/1 Kentucky #9/Kentucky #11

2000 Polk IGCC Fuels and Shutdown Causes

Sun	Mon	Tu	Wed	Thu	Fri	Sat	
						01/01	
01/02	01/03	01/04	01/05	01/06	01/07	01/08	
01/09	01/10	01/11	01/12	01/13	01/14	01/15	
01/16	01/17	01/18	01/19	01/20	01/21	01/22	
01/23	01/24	01/25	01/26	01/27	01/28	01/29	
01/30	01/31	02/01	02/02	02/03	02/04	02/05	Clean CSC's, Rebuild Geho
02/06	02/07	02/08	02/09	02/10	02/11	02/12	ST Main Breaker Ground
02/13	02/14	02/15	02/16	02/17	02/18	02/19	
02/20	02/21	02/22	02/23	02/24	02/25	02/26	Planned Outage:
02/27	02/28	02/29	03/01	03/02	03/03	03/04	CT Hot Gas Path Inspection
03/05	03/06	03/07	03/08	03/09	03/10	03/11	Gasifier Throat Refractory
03/12	03/13	03/14	03/15	03/16	03/17	03/18	ASU Cold Box Leak
03/19	03/20	03/21	03/22	03/23	03/24	03/25	
03/26	03/27	03/28	03/29	03/30	03/31	04/01	
04/02	04/03	04/04	04/05	04/06	04/07	04/08	Atomizing Air Compressor
04/09	04/10	04/11	04/12	04/13	04/14	04/15	
04/16	04/17	04/18	04/19	04/20	04/21	04/22	
04/23	04/24	04/25	04/26	04/27	04/28	04/29	
04/30	05/01	05/02	05/03	05/04	05/05	05/06	
05/07	05/08	05/09	05/10	05/11	05/12	05/13	
05/14	05/15	05/16	05/17	05/18	05/19	05/20	
05/21	05/22	05/23	05/24	05/25	05/26	05/27	
05/28	05/29	05/30	05/31	06/01	06/02	06/03	
06/04	06/05	06/06	06/07	06/08	06/09	06/10	
06/11	06/12	06/13	06/14	06/15	06/16	06/17	
06/18	06/19	06/20	06/21	06/22	06/23	06/24	
06/25	06/26	06/27	06/28	06/29	06/30	07/01	CSC's, Geho, MAC Coolers

Sun	Mon	Tu	Wed	Thu	Fri	Sat	
07/02	07/03	07/04	07/05	07/06	07/07	07/08	
07/09	07/10	07/11	07/12	07/13	07/14	07/15	
07/16	07/17	07/18	07/19	07/20	07/21	07/22	
07/23	07/24	07/25	07/26	07/27	07/28	07/29	
07/30	07/31	08/01	08/02	08/03	08/04	08/05	
08/06	08/07	08/08	08/09	08/10	08/11	08/12	
08/13	08/14	08/15	08/16	08/17	08/18	08/19	
08/20	08/21	08/22	08/23	08/24	08/25	08/26	
08/27	08/28	08/29	08/30	08/31	09/01	09/02	CT Restart Failure: Fuel Fire
09/03	09/04	09/05	09/06	09/07	09/08	09/09	
09/10	09/11	09/12	09/13	09/14	09/15	09/16	
09/17	09/18	09/19	09/20	09/21	09/22	09/23	
09/24	09/25	09/26	09/27	09/28	09/29	09/30	DGAN Suction Vent
10/01	10/02	10/03	10/04	10/05	10/06	10/07	
10/08	10/09	10/10	10/11	10/12	10/13	10/14	
10/15	10/16	10/17	10/18	10/19	10/20	10/21	
10/22	10/23	10/24	10/25	10/26	10/27	10/28	Nozzle Scrubber Leak
10/29	10/30	10/31	11/01	11/02	11/03	11/04	
11/05	11/06	11/07	11/08	11/09	11/10	11/11	
11/12	11/13	11/14	11/15	11/16	11/17	11/18	
11/19	11/20	11/21	11/22	11/23	11/24	11/25	
11/26	11/27	11/28	11/29	11/30	12/01	12/02	
12/03	12/04	12/05	12/06	12/07	12/08	12/09	MDEA Heat Stable Salts
12/10	12/11	12/12	12/13	12/14	12/15	12/16	
12/17	12/18	12/19	12/20	12/21	12/22	12/23	
12/24	12/25	12/26	12/27	12/28	12/29	12/30	
12/31							

FUEL LEGEND:




- Cumberland Pittsburgh #8
- Blacksville Pittsburgh #8
- Blacksville / Cumberland Blend

- Kentucky #9 - Peabody Camp
- Black Beauty Indiana #5 / Pet Coke Blend




2001 Polk IGCC Fuels and Shutdown Causes

Sun	Mon	Tu	Wed	Thu	Fri	Sat	
	01/01	01/02	01/03	01/04	01/05	01/06	
01/07	01/08	01/09	01/10	01/11	01/12	01/13	MAC Discharge Vent I/P
01/14	01/15	01/16	01/17	01/18	01/19	01/20	
01/21	01/22	01/23	01/24	01/25	01/26	01/27	RSC Lower Seal
01/28	01/29	01/30	01/31	02/01	02/02	02/03	
02/04	02/05	02/06	02/07	02/08	02/09	02/10	
02/11	02/12	02/13	02/14	02/15	02/16	02/17	
02/18	02/19	02/20	02/21	02/22	02/23	02/24	
02/25	02/26	02/27	02/28	03/01	03/02	03/03	CSC Plugging/Tube Leak
03/04	03/05	03/06	03/07	03/08	03/09	03/10	
03/11	03/12	03/13	03/14	03/15	03/16	03/17	Planned Outage:
03/18	03/19	03/20	03/21	03/22	03/23	03/24	Refractory Vertical Hot Face
03/25	03/26	03/27	03/28	03/29	03/30	03/31	CT Combustion Inspection
04/01	04/02	04/03	04/04	04/05	04/06	04/07	
04/08	04/09	04/10	04/11	04/12	04/13	04/14	
04/15	04/16	04/17	04/18	04/19	04/20	04/21	
04/22	04/23	04/24	04/25	04/26	04/27	04/28	
04/29	04/30	05/01	05/02	05/03	05/04	05/05	
05/06	05/07	05/08	05/09	05/10	05/11	05/12	
05/13	05/14	05/15	05/16	05/17	05/18	05/19	
05/20	05/21	05/22	05/23	05/24	05/25	05/26	RSC Exit Plug-Sootblower
05/27	05/28	05/29	05/30	05/31	06/01	06/02	MAC 4th Stage Impeller
06/03	06/04	06/05	06/06	06/07	06/08	06/09	
06/10	06/11	06/12	06/13	06/14	06/15	06/16	
06/17	06/18	06/19	06/20	06/21	06/22	06/23	
06/24	06/25	06/26	06/27	06/28	06/29	06/30	

FUEL LEGEND:

	Pittsburgh #8 - Cumberland
	60% Powhatan / 40% South American
	South American / Black Beauty / Pet Coke Blend

Sun	Mon	Tu	Wed	Thu	Fri	Sat	
07/01	07/02	07/03	07/04	07/05	07/06	07/07	
07/08	07/09	07/10	07/11	07/12	07/13	07/14	MAC Discharge Vent Valve Solenoid
07/15	07/16	07/17	07/18	07/19	07/20	07/21	
07/22	07/23	07/24	07/25	07/26	07/27	07/28	
07/29	07/30	07/31	08/01	08/02	08/03	08/04	COS Catalyst Plugging
08/05	08/06	08/07	08/08	08/09	08/10	08/11	
08/12	08/13	08/14	08/15	08/16	08/17	08/18	
08/19	08/20	08/21	08/22	08/23	08/24	08/25	
08/26	08/27	08/28	08/29	08/30	08/31	09/01	Scrubber B Pigtail Leak, O2 Vent Valve
09/02	09/03	09/04	09/05	09/06	09/07	09/08	
09/09	09/10	09/11	09/12	09/13	09/14	09/15	
09/16	09/17	09/18	09/19	09/20	09/21	09/22	Slag Disposal, Sootblower Removal
09/23	09/24	09/25	09/26	09/27	09/28	09/29	
09/30	10/01	10/02	10/03	10/04	10/05	10/06	
10/07	10/08	10/09	10/10	10/11	10/12	10/13	
10/14	10/15	10/16	10/17	10/18	10/19	10/20	LH Recirculation Line Fitting Failure
10/21	10/22	10/23	10/24	10/25	10/26	10/27	
10/28	10/29	10/30	10/31	11/01	11/02	11/03	Nozzle Scrubber A Barrel Crack
11/04	11/05	11/06	11/07	11/08	11/09	11/10	CSC Plugging
11/11	11/12	11/13	11/14	11/15	11/16	11/17	Failed Elbow, Syngas to Scrubber
11/18	11/19	11/20	11/21	11/22	11/23	11/24	
11/25	11/26	11/27	11/28	11/29	11/30	12/01	
12/02	12/03	12/04	12/05	12/06	12/07	12/08	
12/09	12/10	12/11	12/12	12/13	12/14	12/15	
12/16	12/17	12/18	12/19	12/20	12/21	12/22	
12/23	12/24	12/25	12/26	12/27	12/28	12/29	
12/30							

	Indiana #5 - Black Beauty
	Kentucky #9 - Peabody Patriot
	1% Biomass in Pet Coke Blend

APPENDIX B - EXCERPT FROM 1996 STARTUP REPORT

SECTION IX C: INITIAL OPERATION

Each section below discusses specific operations issues by plant area.

POWER GENERATION

1. COMBUSTION TURBINE MODIFICATIONS

During the checkout and start up of the General Electric Supplied combustion turbine (CT), modifications were made to correct issues discovered during the checkout of similar machines that had been put in service prior to Polk turbine being made ready for service. The corrections discussed below were all made by General Electric and paid for by General Electric. No Impact to the overall Plant start-up schedule occurred. All of the design changes made were done in cooperation with Tampa Electric's integrated start-up and operations team.

A) **2-3 Spacer Modification** - During the installation of the turbine a modification was required to the spacer between the 2nd and 3rd stage turbine wheels to prevent the third stage wheel from rubbing against the spacer plate during operation. The modification was made in place and has resulted in error free operation.

B) **3rd Stage Bolts** - During the second combustion turbine syngas run, Tampa Electric had to shut down the turbine on Sunday Morning October 13, 1996, due to changing vibration readings. Tampa Electric had been cautioned that cracking of the 3rd stage connector bolts had been observed on similar units and that a change in vibration vectors would be indicative of the bolt(s) beginning to shear. Upon inspection of the bolts after shut down one significant crack was observed and the bolts were replaced with higher strength material. Subsequent runs of the machine have indicated the problem has been corrected. Tampa Electric will continue to monitor vibration as well as continue inspections as needed during outages to insure no further problems will occur.

C) **Exhaust Temperature Spread** - Due to an uneven distribution of syngas and nitrogen to the fuel nozzles, the combustion temperatures and hence exhaust temperatures were not consistent in the turbine. To correct the problem, orifices were placed in both distribution headers. This resulted in a more balanced flow to the fuel nozzles and hence a more consistent firing temperature. Tampa Electric continues to monitor the temperature spread to insure the modified flow distribution is adequate. There is concern that particulates are forming in the syngas between the gasifier and the CT as a result of chemical phenomenon not yet fully understood. This particulate appears to be plugging the fuel nozzle and further complicating the exhaust

temperature spray. GE, Texaco and TEC continue to investigate the full impact of this phenomenon.

D) Purge Nitrogen - High Pressure nitrogen is supplied to the Combustion Turbine Syngas Control Valve Skid for two (2) reasons. (1) Nitrogen is utilized to purge the syngas lines when transferring from one fuel to the other. (2) Nitrogen maintains a buffer between the syngas and the compressor discharge air, when the CT is on distillate fuel. Due to problems with supplying adequate volumes of purge nitrogen, modifications were performed to provide a consistent volume of nitrogen. In addition with an adequate supply of purge nitrogen available the flow switches would consistently clog preventing a transfer. The flow switches have been relocated and transfers will continue to be monitored closely to insure the problems have been resolved.

In starting up the CT, there is a time when the turbine must burn distillate fuel in preparation for transferring to syngas. During this point in operation, it is vital that the syngas fuel and compressor discharge air do not mix. To maintain this separation a buffer of nitrogen is provided between the closed speed ratio valve and the closed syngas control valve. The Nitrogen pressure has been difficult to maintain because of leakage within the syngas control valves. The seat clearances have been adjusted by the manufacturer but these valves continue to be a problem. GE and the valve manufacturer continue to work on these problems.

E) Diluent Nitrogen Injection Control Valve - Upon initial syngas operation, it was discovered the nitrogen control valve was undersized and the required volume of nitrogen required for NO_x control could not be achieved. A new valve was installed during the late February 97 outage. Since this outage, full load has been achieved and NO_x values have been within compliance.

F) Generator Core Vibration - During the initial start-up & testing, the generator made a loud 3600-hertz noise as a result of resonant condition on the stator core. Belly bands were installed around the stator core and the problem was corrected.

G) HRSG Fouling - During the December 1996, & January 1997 syngas runs, fouling occurred in the L.P. Economizer of the HRSG. The fouling appeared to be from condensing sulfur compounds even though the exit gas temperatures were above the dew point. The operating procedure has been revised to raise the incoming L.P. Economizer inlet water temperature. At the same time the exit gas temperature has been raised slightly. The fouling appears to be arrested in the latest operating runs. We will however, continue to observe the relationships between fuel quality, exit gas temperature, and fouling in order to maximize plant efficiency without sacrificing future availability.

H) End Covers/Fuel Nozzles - During initial testing of the turbine, we were notified by General Electric that there was a potential problem with the brazed joints that separate the syngas from the atomizing air within the end cover. Inspections

verified that a problem did exist and the end cover inserts were rebrazed, correcting this deficiency. However, during the first syngas run, syngas and atomizing air did in fact mix in several end covers due to a design deficiency. This problem was expediently resolved by the manufacture and no other problems have occurred since the repairs were completed.

GASIFICATION

1. GASIFIER REFRACTORY WEAR

The original refractory liner placed in the Polk gasifier is considered a start-up liner. This liner was installed with slightly lower grade, less expensive bricks with the concept being that it would last through the start-up period where there is a higher risk of excursions that would damage any type of liner. Original estimates were that this liner would last approximately one year under the conditions expected for a normal start-up (i.e., Several start-up and shut-down cycles, temperature excursions, etc.).

Inspections have been performed at periodic times throughout the start-up and early operation period. The data collected is summarized below. In general, the refractory has held up well and could be expected to last the 1 year elapsed time as projected. However, due to other considerations (i.e., outage scheduling), we will replace this start-up liner in April 1997.

Replacement plans call for upgrading the refractory in areas of observed high wear. TEC will put less expensive bricks in areas that have exhibited lower wear rates. Goals in partitioning the gasifier in this manner are to minimize cost and to have an entire liner that wears uniformly and will need to be replaced at the same time. The estimated life for the liner to be used for this replacement is 2 years.

2. RSC OUTLET TEMPERATURE

The radiant syngas cooler (RSC) outlet temperature is a function of several factors including inlet temperature, gas flow and composition, heat exchange surface area, steam conditions and gas side fouling factor. The outlet temperature in operation has been significantly below the design outlet temperature. This is a result of several of the factors listed, but primarily due to lower than design gas side fouling.

The start-up coal at Polk, Pittsburgh #8, has not fouled the heat exchange surface in the RSC as expected. Testing on alternate coals will be conducted in early 1997. This testing will provide significant information on RSC performance that can be used to optimize the outlet temperature based on performance and capabilities of downstream equipment. Until this testing is completed, no action to modify RSC outlet temperature is planned. The process configuration has enough flexibility to allow continued operation at this reduced temperature with only minor downstream effects.

RSC outlet temperature (deg F)

Expected Temp. Design Case	1400
Expected Temp. Normal Operating Case	1300
Actual Operation	1040*

*The actual temperature listed is an average temperature of 4 thermocouples located at the exit of the RSC. This temperature varies with run duration and the number presented is typical for a normal run.

3. CONVECTIVE SYNGAS COOLING SYSTEM

The Convective Syngas Cooling System (CSC) consists of a total of 6 heat exchangers and interconnecting piping. All six of the exchangers are fire-tube type shell and tube heat exchangers. Each wing of the gasifier has one convective cooler which has hot, raw syngas on the tube side and raises high pressure steam on the shell side. Next, the gas passes to a two stage gas to gas type exchanger with hot, raw syngas on the tube side and either clean gas or nitrogen on the shell side. Each wing of the gasifier has the three exchangers in the arrangement discussed above to form the entire convective syngas cooling system.

From a process standpoint, this cooling system has performed well in the early phases of operation. The gas temperature at the inlet to this system (the same gas that is at the RSC exit) has been significantly below the design estimates. The tube side fouling factors estimated for design purposes have also been lower than expected. This results in the need to partially bypass these exchangers during operation in order to maintain temperatures above dew point at the exit of the system. However, because of the overall process relationship of the system, the bypass operation has only a minor effect on the overall plant efficiency.

The most serious problem experienced in this area of the plant has been ash plugging in the tubes of the gas to gas exchangers during the early phases of plant operation. This ash pluggage resulted in several shutdowns and required extensive clean-up procedures. TEC held several discussions with the equipment supplier and performed extensive analysis of the ash material and tube configuration. Based on this work, it was determined that TEC had to increase the velocity of the gas in this section of the plant. In addition, it was found that there was a correlation in the operating characteristics of the gasifier (ie. operating temperature) and the plugging characteristics of the ash. To increase the gas velocity, several tubes in the exchanger were blocked or plugged. This did decrease the duty available in these exchangers. However, as discussed above, there was significant margin in these exchangers due to lower than expected inlet temperatures.

Another area of concern in the design phase was erosion from the ash laden gas in the tubes of these heat exchangers. The increase in gas velocity to prevent pluggage

increased the concerns for erosion damage. The inlet side of all six exchangers have ferrules that serve to direct the gas into the tubes and to protect the tubesheet and tube inlets. These ferrules are designed to be replaceable and are considered sacrificial in the sense that they are expected to erode over time and be replaced. Based on early results of inspections, we have estimated that the ferrules that are currently being used will last approximately 1 to 1 2 years.

Another area of significant problems that have been experienced in the gas-to-gas exchangers has been with tube side corrosion. TEC has seen significant pitting damage in the tubes of all four stages of the gas-to-gas exchangers. This pitting damage has been determined to be a result of down time corrosion associated with chloride attack on the stainless steel heat exchanger tubes. As a temporary solution, TEC has taken steps to minimize the potential for continued attack by maintaining high temperatures in this area during plant shutdowns and by performing extensive cleaning procedures when cool down is required.

4. BLACK WATER SYSTEM OPERATION

Several issues concerning the operation of the Black Water system were resolved during the initial testing and start up of the unit. The key issues are discussed below;

A) The slag dewatering return line to the vacuum flash drum continually plugged during initial operation. The high content of slag remaining in the black water caused handling problems. To correct the situation the vacuum drum was bypassed and this portion of blackwater was sent directly to the gravity settler. The operation of the unit is only slightly affected. The primary concern is related to the higher levels of air/oxygen in the black water leading to advanced rates of corrosion in the piping and equipment. Tampa Electric continues to monitor the situation to insure adequate operation of the system.

B) In order to enhance the settling capability of the gravity settler, flocculent is added to the blackwater. Upon initial operation it was found additional flocculent was needed in the system. Additional injection points were installed at minimal cost and satisfactory operation was achieved.

C) Due to the higher than expected ash content and lower carbon conversion ratios, the black water system is running at maximum capacity. Any upset condition with the coal supply resulting in higher ash content can lead to a trip condition. An acceptable margin of 5% to 10% is needed to increase the reliability of the plant. Tampa Electric continues to evaluate solutions to this problem.

D) The actual velocities and flows being encountered in the black water system near control valves are leading to higher than expected erosion rates in the system. Tampa Electric expects to solve the problem by replacing affected areas with erosion resistant materials.

5. GREY WATER SYSTEM OPERATION

The grey water system operation is producing more grey water than the plant can use within the normal internal loops. Higher than expected purge flows are producing more black water than expected, in turn overloading the grey water system. The Plant currently recycles the additional grey water to the slurry preparation system to maintain the grey water inventory. This is only a temporary solution until a permanent fix is implemented to reduce/reuse the grey water.

6. BRINE SYSTEM OPERATION

The Brine system is part of the new technology being demonstrated at Polk Power Station. Tampa Electric is currently evaluating alternatives to resolve numerous problems in this system. Options being considered include replacing the existing brine unit with different technology versus increasing the capacity of the existing unit and remaining with the same technology.

Carryover into the falling film evaporator blowers is causing significant corrosion. Modifications are being made to the existing system to help minimize this problem. However, further major modifications may require including new compressors and inlet piping, along with an additional vapor separator.

Severe corrosion has been experienced in the forced circulation system. Metallurgy changes are underway that appear to minimize this corrosion on the present fuel.

Major piping and control modifications are being made to the crystallization system to allow operability and availability of the system.

HOT GAS CLEANUP STATUS REPORT

The HGCU system has been functionally checked out and is ready to proceed as described below. The change in schedule for the HGCU testing has not impacted the operation of the balance of the plant.

1. INLET EXPANSION JOINT

The inlet expansion joint failed during initial operation and was found to have had a fabrication problem and was partly due to the materials used. The material was upgraded and the repaired joint is on site. Installation is pending due to pluggage in the gas/gas exchanger, determination of the causes for the lower than expected syngas temperatures coming from the RSC, and a confirmed recommendation for a long term sorbent material.

2. CONTROL LOGIC PROBLEMS

During the testing of the sorbent transfer sequence prior to commencing the attrition test, the following problems occurred:

- A) It was determined that the skip hoist was under sized based on the current logic that assumes two full loads to empty the regenerator sorbent lockhopper. In order to correct the problem the rotary feeder was calibrated to determine a speed versus flowrate curve which can be used to calculate the volume of sorbent transferred in a given amount of time.
- B) There were mechanical problems with several valves and incorrect control logic for the pressurization and depressurization of the sorbent vessels. The valves will be repaired and the logic modified and tuned to assure the purges are properly completed.
- C) The nuclear level switches need to be recalibrated, some were too sensitive and others not sensitive enough.

The Attrition test scheduled for 1996 has been postponed due to operational and control logic problems that were encountered during the sorbent transfer sequences as noted above. The attrition test will resume in 1997 pending resolution of the above-mentioned problems.

AIR SEPARATION UNIT

1. START-UP CONCERN - MAIN AIR COMPRESSOR

The start up of the Main Air Compressor (MAC) went smoothly with the exception of vibration levels higher than contract requirements for the MAC motor. The motor rotates at 1200 rpm and the contract required vibration to be 2.0 mils or less peak to peak. Data on the distributed control system (DCS) indicated vibration levels as high as 4 to 4.5 mils on the motor bearings. The motor was monitored for any change in vibration and the issue discussed with both Air Products and Chemicals, Inc. as well as the motor manufacturer GE - Canada.

With the vibration levels not meeting contract requirements, it was decided to remove the motor rotor and inspect for possible causes. Rotor straightness and pole face hardness testing was done which showed that the rotor had a bow of approximately 6 mils and there were significant differences in the pole face hardness readings. It was decided to rebalance the rotor to account for the bow and reinstall the rotor.

The machine was placed back into service and vibration readings were taken. The vibration levels after the balancing did meet the contract requirements and have been monitored since. The cost of the removal and balancing was covered as a warranty

item and did not have any impact on project costs. An extended warranty for an additional seven years was requested and received from Air Products on the motor rotor.

2. AUXILIARY LOAD LEVELS

The auxiliary load of the ASU has a significant effect on overall plant heat rate and net output. The power consumption of the ASU is slightly more than design, but tuning of the advanced controls have reduced this amount some. The power consumption will be recorded as part of the ASU performance test to be conducted in early 1997.

SULFURIC ACID PLANT

The Sulfuric Acid plant has worked well during the initial start up. Changes associated with the initial start up of the plant are detailed below.

1. LOW INLET SULFUR

The Pittsburgh #8 coal currently being burned is approximately 2.5% sulfur and the sulfuric acid plant is designed for a 3.5% sulfur coal. Analysis of the incoming coal has indicated that sulfur content is running slightly lower than 2.5% as well. The lower sulfur content of the coal forces the acid plant to run in a turned down mode which has operational implications. It was difficult at times during start-up and early operation to maintain proper temperatures in the converter and the decomposition furnace. Supplemental firing of propane was required to maintain temperatures in the equipment. The lower than designed sulfur content of the coal currently being burned has reduced the output of sulfuric acid generated as a by-product. It is anticipated that the sulfuric acid plant will be able to accommodate a 3.5% sulfur coal without any operational problems.

SUPPORT FACILITIES

Immediately after gasifier start-up, raw syngas is routed from a point directly downstream of the syngas scrubbers through the raw gas flare valves. It then flows directly to the flare knockout (KO) drum where it was to bubble through a water pool which was to form a water seal, preventing air intrusion into the flare headers when the gas flow stopped. From the flare KO drum, it flows directly to the Flare. Soon thereafter in the start-up sequence, the syngas is routed downstream through low temperature gas cooling and acid gas removal. It is reheated in the Raw Gas/Clean Gas Exchanger and flows through the clean gas flare valve to a different part of the flare system. The flare KO drum, main flare header, and flare itself are only designed for 500°F, but the gas from the Raw Gas/Clean Gas Exchanger was expected to be 650°F. So first it is cooled with a direct water spray, then introduced into another water pool in the flare quench drum to assure it is sufficiently cooled in the event of failure of the water spray system and/or associated controls before entering the flare KO drum. Meanwhile, acid gas from acid gas removal and Ammonia Stripper off gas

are being generated. These streams must be flared until the sulfuric acid plant is brought on line. These two streams flow through a separate acid gas flare header to the Flare KO Drum. The Ammonia Stripper off-gas is the last stream to be introduced into the acid plant, so it is flared the longest. Described below are design modifications that had to be implemented during the unit start up.

1. ACID GAS ABSORBER

Foaming in the Acid Gas Absorber was encountered. The foaming was determined to be in the Acid Gas Absorber due to the following: High Column Differential Pressure, Level indications in the Clean Gas Knockout Drum, and Poor H₂S Absorption with Lean Amine. To correct the problem a defoamer injection system was implemented. Defoamer was added to the system to remove the foaming. Dose and continuous injection methods are being tried to find the appropriate technique to ensure amine tray froth without foaming. No noticeable foaming indicators have appeared in the Acid Gas Absorber since defoamer dosing and continuous addition testing were begun. The Clean Gas Knockout Drum has remained empty.

The initial system operated with an Activated Carbon Filter for amine cleaning but no defoamer addition. The addition of the defoamer injection caused the unit to have a more efficient running capacity since. Causes of foaming (other than hydrocarbons) could be found while the unit is still running. With the previous system (no defoamer addition) the system was protected against hydrocarbon and particulate foaming through filtration, but other nonfilterable agents could have caused foaming.

2. HIGH H₂S LEVELS IN CLEAN SYNGAS

The percent of sulfur capture in AGR unit went down as high levels of Heat Stable Salts (HSS) were formed. This resulted in higher H₂S levels in the clean syngas. Caustic dosing was implemented. The caustic dosing frees the MDEA from the Heat Stable Salts that form. Also, a mobile Amine Reclamation unit is being utilized on site to extract the Heat Stable Salts from the MDEA. A permanent hookup has been established within the AGR system for reclamation. This reclamation method can be utilized whether the AGR system is online or offline. The caustic addition allows us to extend the period before reclamation. Also, the amine is free to work at nearly full (i.e. 50% solution) strength. The MDEA reclamation removes the H₂S. This frees the amine once H₂S content have become high enough to make the caustic addition treatment ineffectual in reducing system corrosivity.

Together the Caustic addition and the MDEA reclaiming increase the normal amine life and provide a cost effective way to retain previously amine purchased amine. Also, both implementations are used online, therefore the syngas would stay online during the amine cleaning. The original system design required offsite amine reclaiming and purchase of fresh amine for refill to continue AGR operation. The AGR system would be taken offline during this process, therefore the syngas would be unclean and stay offline.

Polk's design for the sulfur removal system was based on Cool Water data, previously the largest Texaco IGCC plant utilizing Polk's general configuration. With the expected 99.5%+ H₂S removal promised by solvent vendors and only 2.5% of the coal's sulfur in the form of COS, Polk could meet present and future emission requirements without removing any COS, so this became the plant's design basis. Although, TEC can meet current emissions restrictions under these conditions with 2.5% sulfur coal, Polk is not producing the quality of fuel which GE expected for the turbine, and Polk may not be able to meet future emissions restrictions if these conditions persist, particularly with less expensive higher sulfur feedstocks.

TEC is making some minor piping modifications to maintain quality of our sulfur removal solvent and investigating the effects of operating parameters such as solvent to gas ratio, solvent introduction point into the Absorber, and solvent stripping rate to improve the H₂S removal efficiency. Ultimately, however, the key to low sulfur emissions is the reduction or removal of COS. The Cool Water data upon which the Polk design was based was taken on four different coals, so there is a reasonable chance that the current high COS production from the Pittsburgh #8 coal being gasified at Polk is an anomaly. The alternate feedstock tests will hopefully show significantly less COS production. If not, concepts such as conventional COS hydrolysis, partial COS removal with modified amine solvents, or some other novel approaches to COS reduction and removal will be aggressively pursued. TEC will continue to update the DOE on any further modifications.

3. SLAG HANDLING MODIFICATIONS

The following table shows that although some aspects of the gasifier performance at recent operating conditions approach Design values, they are far from commercially expected values.

Slag Characteristics and Refractory Liner Life

	Recent Full Load Operation (Before Changes)	Design Value (Design Case)	Commercial Expectation (Normal Operating Case)
Slag Carbon Content (Weight % Dry Basis)	34	28	14
Slag Quantity (Dry Tons/Day)	250	215	185
Heating Value Lost To Slag (MMBTU/Hr HHV)	70	50	20
Refractory Liner Life (Years at 85% On-Stream Factor)	:	2	2

Carbon conversion can be increased at the expense of refractory liner life, and vice-versa, by adjusting gasifier temperature. However, as can be seen from the table, there is little available to sacrifice on either parameter. The higher than expected carbon content of the slag creates handling problems and makes it a less desirable byproduct for many applications. It also increases the mass and volume of the material we must handle, making our slag and fines handling areas extremely labor intensive. Furthermore, the heating value of the carbon lost with the slag increases net plant heat rate by 75 to 200 BTU/KWH. The current start-up gasifier refractory liner is less expensive with reduced slag resistance compared to the material we expect to use long-term. Our first liner replacement is scheduled for April 1997. It will be a more slag-resistant material, so at current operating conditions, it may approach our commercial expectations of a 2 year liner life. However, feed injector adjustments to improve carbon conversion at less severe reactor conditions are still required for us to realize our commercial expectations for liner life, heat rate, and slag quantity/quality.

4. FLARE SYSTEM CHANGES

Changes made to the flare system are discussed below;

A) Flare Drum Sizing / Water Carryover / Flooding

Both the Flare KO Drum and Quench Drum were not large enough to permit the gas to bubble through their water pools. Instead, the water literally blew out of the drums into the downstream equipment even at relatively low start-up rates. Water from the Flare Quench Drum blew into the Flare KO Drum. From there, the water from the KO Drum blew into the flare stack itself. Relatively small amounts of particulates and Acid Gas Removal Solvent carryover into the drums during early operation caused foaming in the drums and made carryover worse. We were concerned that pressure dynamics (water hammer) associated with the conveyor could mechanically damage the Flare Stack itself at a time when it was most needed.

To correct the problem an additional drum to accommodate excess water from the Flare KO Drum was added, the water removal piping was rerouted to permit more flow, and the flare system operating procedures were completely revised to use nitrogen purges instead of water pools in the drums to prevent air intrusion. Since the changes, dangerous situations due to excessive water in the Flare KO Drum have not occurred. TECO has thoroughly reviewed the revised operating procedures for the flare system, and are comfortable that they are adequate and safe. Nevertheless, TEC has commissioned a third party audit of the flare system and the associated operating procedures since the initial configuration was deficient and the new operating concept is dramatically different. It is possible that additional modifications will still be required. Results of this audit will be presented to DOE when it is complete.

B) Acid Gas Flare Header

The Ammonia Stripper off gas flows with the MDEA acid gas to the Flare KO Drum through the Acid Gas Flare Header during start-up. Mixing the ammonia laden Ammonia Stripper off gas with the CO₂ rich acid gas formed salts which once plugged the uninsulated and untraced header, creating a potentially dangerous operating scenario.

A separate traced and insulated header will be installed from the Ammonia Stripper to the Flare KO Drum to prevent contact between the ammonia laden Stripper off gas and the CO₂ rich MDEA acid gas. In the mean time, occasional steam purges, heavy water flushes, and high stripper overhead operating temperatures have prevented recurrence of header plugging.

C) Ammonia Stripper Overhead Piping/Valve Sizing

The Ammonia Stripper overhead piping and valves were not sized to accommodate the ammonia in the stream, only the other minor components. Consequently, it was not possible to pass the full Stripper off gas flow to the Sulfuric Acid Plant or occasionally to the Flare without opening the control valve bypasses or lifting safety valves. Quality of the tracing of this piping was also questionable, and the overhead piping plugged with salts quite often. This also created a potentially dangerous operating scenario.

Properly sized and well traced and insulated valves and piping have been installed. The new piping and valves now comfortably handle the required flows at full rate.

5. SLURRY PREPARATION

The work in the slurry preparation area of the plant has focused primarily in two areas; (1) equipment problems associated mainly with the rod mills, and (2) performance issues associated with particle size distribution, fines and water recycle, and slurry viscosity.

A) Slurry Preparation Area Equipment Problems

The equipment in the slurry preparation area of the plant has performed relatively well with the exception of the rod mills which are used to grind the dry coal with water to produce a slurry suitable for pumping. During initial commissioning of the mills they exhibited unacceptable vibration. This problem was determined to be associated with the stiffness of the foundations under the rod mills (note: the mills are installed 30-40 feet above grade on concrete foundations). Additional concrete was added in two steps to eventually resolve the problem.

Another area of ongoing concern for the rod mills has been consistent leaking of the mill liner bolts. When these bolts leak, slurry builds up on the outer diameter of the

mill and eventually spreads to the area and equipment surrounding the mills. TEC is still working with the mill OEM to resolve this problem. TEC has gone through several cycles of re-torquing and also double nutted all the mill liner bolts. These steps only work temporarily and leaking resumes after a short amount of run time.

Other equipment problems that have been experienced in the slurry preparation area include the vibrating screens and the slurry transfer pumps. The screens experienced periodic plugging through early operation and were replaced with screens with a larger mesh opening. The slurry transfer pumps have experienced considerable wear and TEC is now trying pumps with modified clearances and liner materials.

B) Slurry Preparation Performance Issues

The performance issues associated with the slurry preparation area are primarily particle size distribution of the coal slurry from the rod mills and related pumping characteristics of the slurry. The particle size distribution of the slurry is a function of the rod charging in the mill. Rod mill motor amps are monitored to determine when to add rods and this has proven to produce consistently acceptable slurry. TEC has experienced some plugging in the slurry piping, however, this has been relatively minor. Routinely these lines are cleared after each use and don't generally experience any problems during operation. The slurry charge pump has performed extremely well with only some moderate wear of the check valve seats.

Other performance related parameters in the slurry preparation area involve the water used for feeding the rod mills and the effect of recycling carbon fines into the slurry. Both of these issues are being evaluated to determine the optimum operating configuration.

6. DISTRIBUTIVE CONTROL SYSTEM (DCS)

Discussed below are changes made to the DCS:

A) Data Historian

The original data historian archived control system data from the DCS to a DEC VAX. It functioned poorly and was difficult to use. Only one user at a time could use it effectively and needed to be VAX-literate. The data historian was replaced with the Oil Systems Inc. PI historian. The major value of the PI historian was its ease of use and that historic data could be trended anywhere on the Plant LAN. Making the data easily available and graphable to all station personnel speeded process problem identification, analysis and solution.

Attachment 3
Polk Power Station Unit 1
Informational Brochures