Sierra Pacific
Resources

Final Technical Report To The Department Of Energy

Pinon Pine IGCC Project

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DISCLAIMER –

ABSTRACT

The Pinon Pine IGCC Project is a joint venture between Sierra Pacific Resources and the United States Department of Energy. The purpose of the project is to demonstrate the commercial use of the KRW air blown coal gasification technology utilizing hot desulfurization and particulate removal technologies. The clean fuel gas is fired in a modern combustion turbine operating in combined cycle mode. Steam generated from the waste heat from the combustion turbine and from the coal gasification process is used to generate electricity in a steam turbine generator. Power is generated from this Integrated Coal Gasification Combined Cycle (IGCC) plant with much lower emissions levels than comparable coal-fired power plants and with greater efficiency.

EXECUTIVE SUMMARY –

The Pinon Pine IGCC Project is a joint venture between Sierra Pacific Resources and the United States Department of Energy. Foster Wheeler USA Corporation and its sister companies, Foster Wheeler Constructors, Incorporated, and Foster Wheeler Power Systems, Incorporated, provided overall project design, procurement, construction management, and startup services. The MW Kellogg Company provided design and procurement of Gasifier Island process, design, and procurement. Westinghouse provided the technology for the filtration of the Syngas. General Electric supplied the turbines for the project.

During the reporting period of the project, construction of the Combined Cycle portion (Power Island) of the unit was completed and start-up of the combustion and steam turbines began in October 1996. The combustion turbine is a new design incorporating 2350°F firing temperature and utilizing steam injection for NOx control. This unit, the General Electric model 6FA, was first fired on August 15, 1996. During the start-up period, some troubles with controls and the steam injection were experienced, the turbine to gearbox coupling failed, and shroud lift problems were encountered with the turbine buckets. All of these problems, with the exception of the continuing problem of premature turbine bucket failure, have been resolved. The performance of the Power Island has been very good, exhibiting high availability (94%).in a base load operating environment.

Construction of the Gasifier, Coal Conveyors, Nitrogen Plant and auxiliaries continued during the start-up phase of the Power Island. Once the construction phase was completed in March 1997, start-up efforts began. The location of the Flare proved to be hazardous to personnel and equipment, so it had to be moved to another location. Start-up was then delayed until safety concerns with the Flare could be addressed. During January, 1998 , start-up of the Gasifier Island first occurred.

During the reporting period of the Pinon Pine IGCC Project, the Gasifier was started up a total of eighteen (18) times. Each start-up failed due to design or equipment flaws. Each subsequent start-up attempt after a failure was not performed until the problem that halted the preceding start-up was addressed. Although this project was to demonstrate the potential for commercial operation of the air blown KRW Gasifier, hot desulfurization, and hot particulate removal, the goal of achieving sustained operation has not yet been accomplished. The start-ups, design problems, and equipment failures are discussed further in Sections 2 and 3 of the report.

The ability of the KRW gasificaton process to produce synthetic gas from coal, of the quality predicted by design, was demonstrated. The light off of the unit needs further development as demonstrated by the accelerated temperature ramps experienced during start-up. Control of the reactor is more easily accomplished at full temperature.

The major problem that halted most of the start-up efforts was the removal of waste materials. The Hot Gas Filter provides final filtration of the Syngas before it firing in the combustion turbine. Failure to remove the fines from the filter vessel caused the bulk of failed start-ups. Modifications were made after each subsequent start-up until some level of success was achieved in the fines removal process. Equipment failure provided the cause for the balance of aborted start-up attempts.

Removal of LASH (ash and limestone) from the lower section of the Gasifier proved to be the next stumbling block. Modifications were made to the LASH removal annulus section and the lower walls of the refractory lined Gasifier vessel. Spalling of the old refractory was constantly plugging up the LASH removal annulus and the internal volume of the annulus proved to be too small to allow sufficient cooling of the LASH. Replacement of the original two layer refractory materials with new single layer refractory and firebrick in selected locations was completed. The modifications were to be tested during the last start-up attempt in August, 2000. The Hot Gas Filter caught on fire and further start-up efforts were halted.

Repairs to the Hot Gas Filter will be completed to allow resumption of start-up efforts. All of the dirty elements have been cleaned and vessels emptied out and inspected. No signs of plugging or corrosion were found.

In 1999, Sierra Pacific Resources merged with Nevada Power Company. As a condition of the merger and in the restructuring of the electric utility industry, Sierra Pacific Power Company is in the process of power generating plant divestiture. Sale of these plants, including the Pinon facility, is currently underway. Further efforts at plant start-up will be decided after discussions with the new owner of the plant.

Gasifier Start-up Summarization Table

Start-up #	Hours Operation	Syngas Production Hours	Syngas Quality BTU/Cubic Ft.
M. W. Kellogg			
1	5	2	129
2	24	0	NA
3	24	9	135
4	120	25	120
5	72	20	145
6	72	18	145
7	144	5	NA
8	72	5	128
9	24	8	145
10	48	4	NA
11	48	0	0
12	48	0	0
13	24	10	NA
14	24	6	NA
15	24	5.5	NA
16	24	4	NA
17	24	6	110
18	120	0	0

Pinon Coal Properties

Sample #	Air Dry Loss	Moist. %	Ash %	Sulfur %	BTU/Lb HHV	Dry Ash %	Dry Sulfur %	Dry BTU/Lb HHV
1	6.63	11.64	7.42	0.31	11241	8.41	0.35	12722
2	7.36	10.72	8.11	0.37	11274	9.08	0.42	12628
3	7.02	10.84	7.49	0.28	11322	8.41	0.31	12699
4	4.20	6.88	9.24	0.64	12324	9.92	0.69	13235
5	6.23	8.86	10.95	0.55	11408	12.02	0.61	12516
6	5.52	9.54	10.36	0.56	11369	11.45	0.62	12568
7	5.92	9.54	10.65	0.49	11278	11.77	0.54	12468
8	6.19	10.96	7.86	0.33	11245	8.83	0.37	12628
9	6.63	10.99	7.92	0.33	11273	8.90	0.37	12665
10	7.74	11.21	8.16	0.34	11212	9.19	0.38	12627
11	7.21	10.98	8.49	0.34	11174	9.54	0.39	12552
12	4.22	6.92	11.39	0.70	12007	12.23	0.75	12900
13	7.91	11.76	9.58	0.40	10868	10.85	0.45	12317
14	6.15	11.22	9.76	0.42	10992	10.99	0.48	12381
15	6.50	11.55	9.68	0.49	11043	10.94	0.55	12485
16	4.89	10.76	8.85	0.48	11224	9.92	0.53	12577
17	2.25	6.40	12.86	0.50	11580	13.74	0.53	12373
18	1.31	5.55	14.64	0.50	11325	15.50	0.53	11991

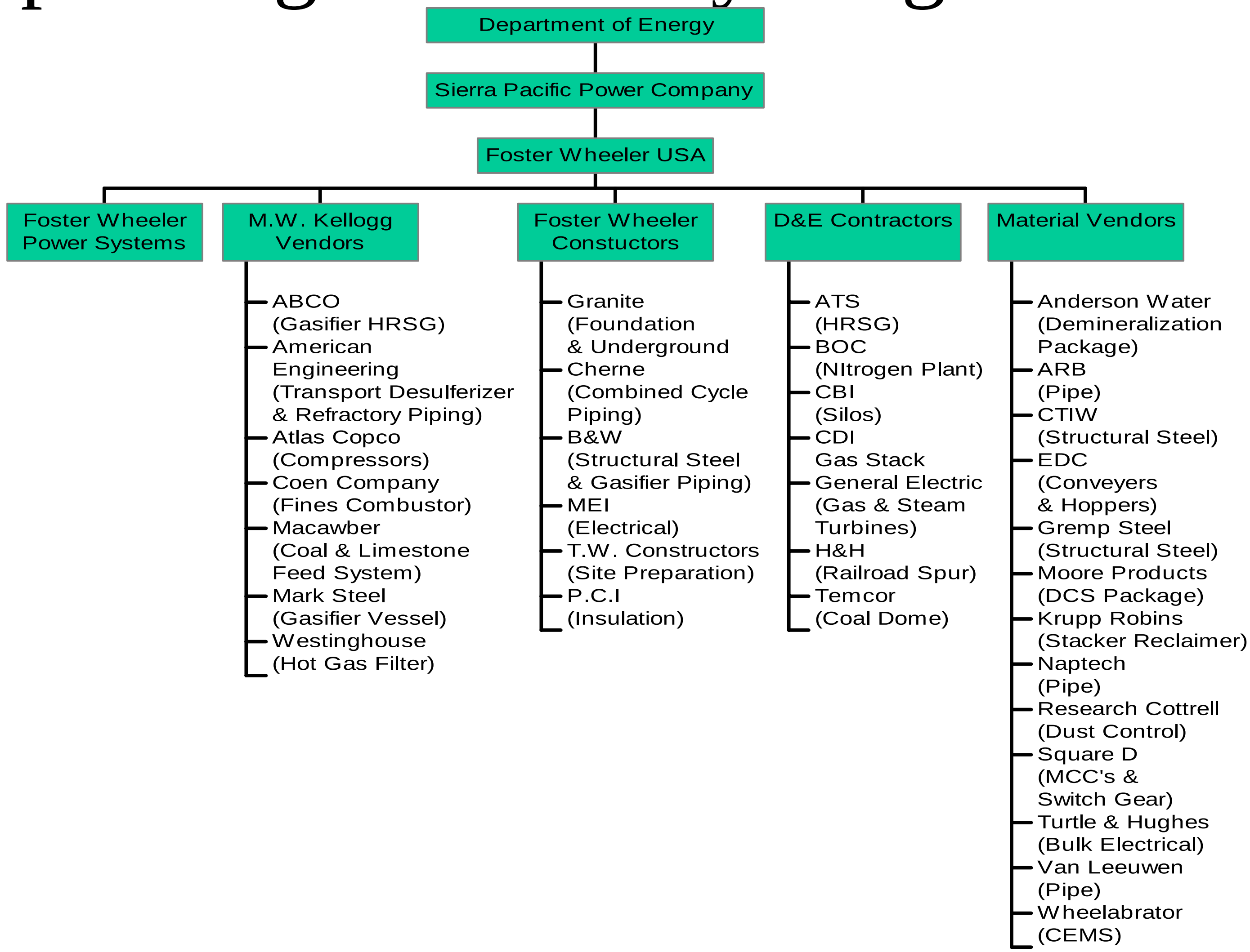
Cost Summary

The cost for a Gasifier start-up was determined to be in the neighborhood $200,000.00 per event. This includes the fuel, operations, and maintenance costs for the facility during start-up periods only. Overtime for 24-hour coverage and extra people is also included. For other cost pertaining to the Pinon Gasifier, see section 5.5, Plant Cost Data.

Milestones

May 1992 – Project selection by DOE.
July 31, 1992 – Cooperative Agreement between DOE and SPPCo.
November 1994 – Environmental Impact Study Completed.
January 1995 – Doe give approval to construct.
January 1, 1996 – Operations and maintenance staffing and training.
July 1, 1996 – Combined Cycle mechanically completed.
August 15, 1996 – Gas Turbine first fire.
October 1996 – Combustion Turbine on line for first time.
December 1, 1996 – Pinon Combined Cycle commercial.
April 1, 1997 – Pinon Gasifier mechanically completed.
December 1997 – Pinon Gasifier start-up begins.
July 1, 1998 – Gasifier Process Specialist position filled.

Reporting Authority Organization



Conclusions

The Pinon Pine Project was intended to prove economical generation of electricity by means of proven combined cycle technology utilizing coal gas. The Combustion Turbine at the Pinon facility is a GE Frame 6, one of only a handful in existence. It's performance on natural gas has been exemplary. The unit has yet to be fired on coal gas.

The Pinon Pine Gasifier was intended to generate low BTU coal gas from coal to be sent to the Combined Cycle. This would offer a means of utilizing coal with clean-up of the gas producing much lower emission rates than conventional plants. The Gasifier is the only unit of it's kind in the world. Several bottle-necks have arisen in the start-up of the unit. It is the intention of the original owner (SPPCo) and the agreed purchaser of the facility (WPS) to continue to push forward and attempt to make the Gasifier commercially viable.

Lessons Learned

As with any new technology, construction and start-up is going to have its share of pitfalls. The following summary will account of the major obstacles that the project has had to overcome:

- Construction delays.
- Start-up delays.
- Capital improvements.
- Scale-up of a model (Gasifier).
- Procedures.
- Procurement of parts. The Gasifier and Frame 6 Combustion Turbine do not have parts just sitting on shelves.

- Lead time to complete projects. Any new improvement or change to process with the Gasifier takes very long periods to implement.

1.0 Introduction and Description of Project

1.1 Introduction

The GE 6FA Combustion Turbine was started up and came on line in October of 1996. Some initial problems with controls were experienced. They were taken care of and the turbine, on natural gas operation, has performed very well ever since. Other problems encountered were coupling failure and premature turbine bucket failure. Replacement of one row of blading, followed by manufacturer alteration of the replaced turbine blades has been accomplished. Recent inspection of the altered blading indicates that shroud lift problems continue in this application and were not resolved with the bucket replacement or the alteratons performed by the manufacturer.

Start-up of the Pinon Pine KRW coal Gasifier began during December of 1997. This is a serial number one unit with brand new air blown technology. The designer of the Gasifier is the M. W. Kellogg Company (Kellogg, Brown, and Root). Foster Wheeler handled construction of the project.

The gasification unit uses air, compressed and blown through a combustion air line, to burn coal in a fluidized bed in reduced atmospheric conditions. The inherent gas driven off from the reaction of the heat, carbon, and steam injected into the bed produce a synthetic gas with approximately 140 BTU/Standard Cubic Ft. This gas will then be used to power the combustion turbine. Reference Figure 1 below.

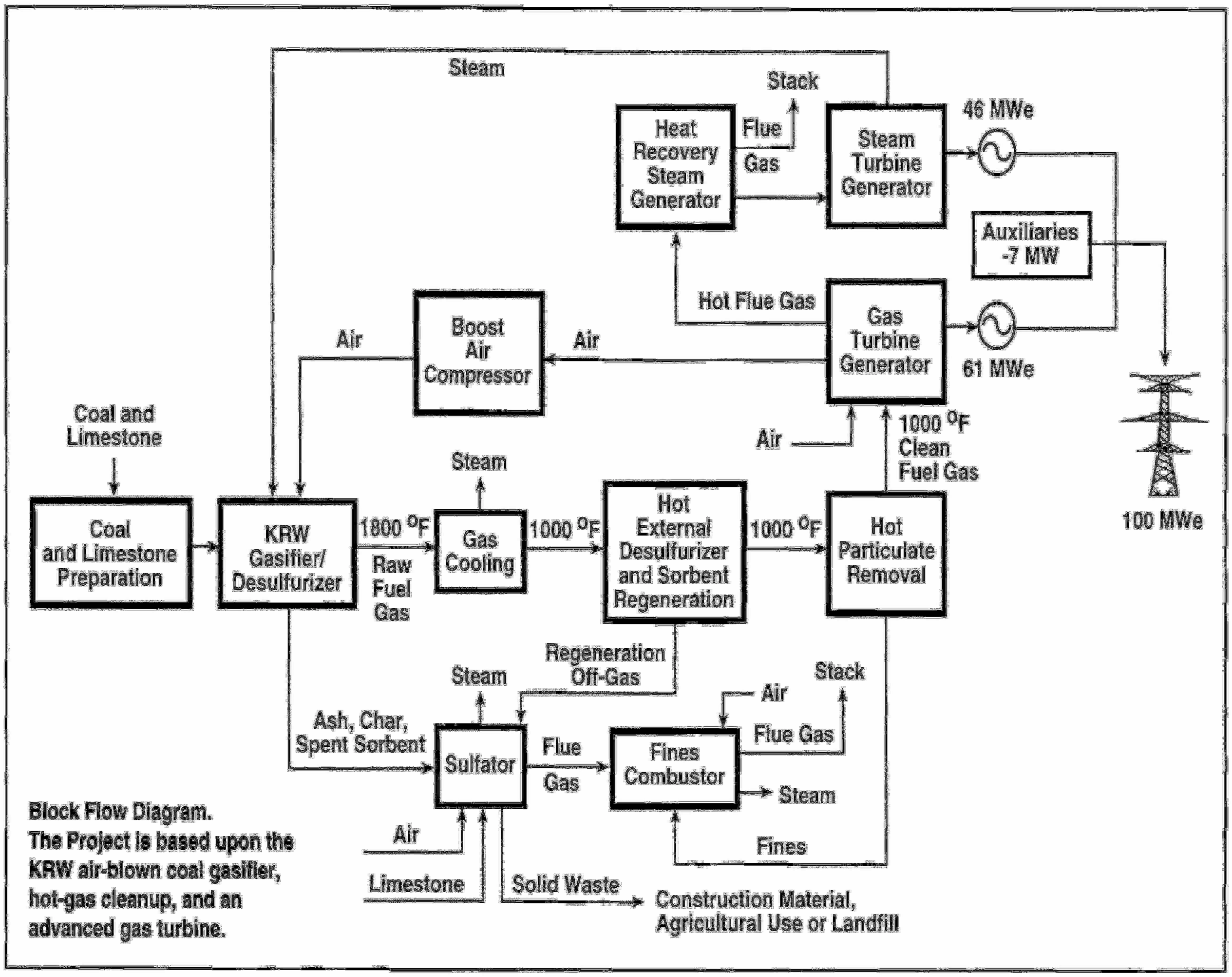


Figure 1 – Gasifier Process Schematic

The clean gas technology utilized in this project was developed with the support of the Department of Energy. It consists of a Desulfurizer reactor (Figure 2), which uses sorbent to remove the sulfur from the gas. The sorbent is then regenerated with hot air and the sulfur dioxide gas driven from the regeneration is sent to a multifunctional fluid bed reactor called the Sulfator. It is here that the ash products, limestone and sulfur are burned to completion. Leftover waste is stored in a silo for landfill use at later time.

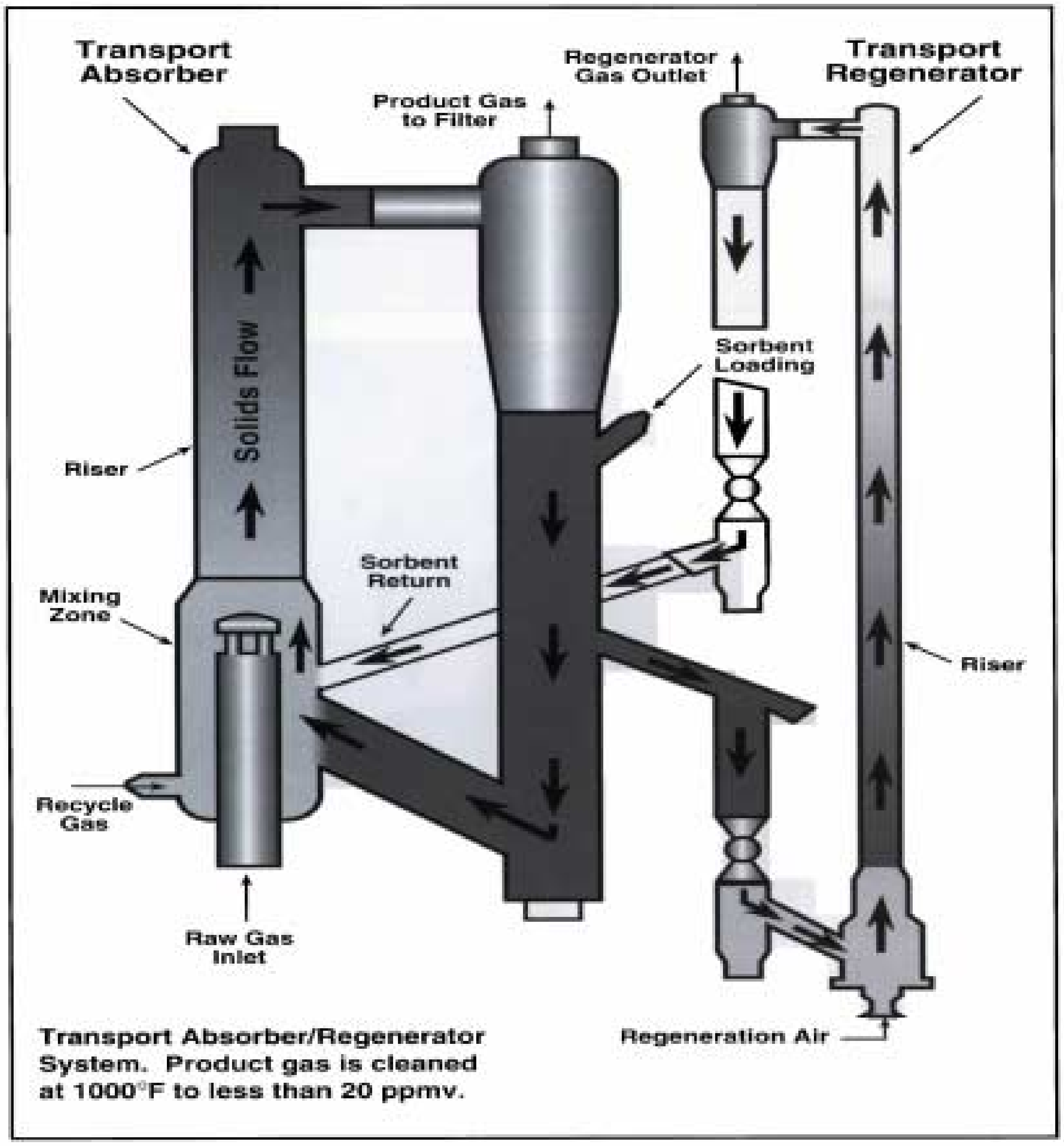


Figure 2 – Hot Gas Clean Up

Fines carried over from the Gasifier are removed by a series of cyclones, which return the particles (40+ microns) to the reactor. Smaller particles are removed in a Westinghouse Hot Gas Filter. The design of the Syngas in the unit is 280 PSIG and 1000°F. The Hot Gas Filter is lined with refractory and has ceramic filter elements inside. Fines are removed from the filters by back pulsing with nitrogen or Syngas. These fines are then taken out of the bottom of the filter by a lockhopper system and burned in the

Fines Combustor. The extra heat produced is used to generate steam for use in the steam turbine portion of the Combined Cycle.

Inside the Gasifier, temperature is controlled to 1800°F. The Syngas exiting the Gasifier is then cooled to 1000°F. The use of this heat generates yet more steam for the steam turbine.

Figure 3 shows an elemental flow diagram of the entire gasification process:

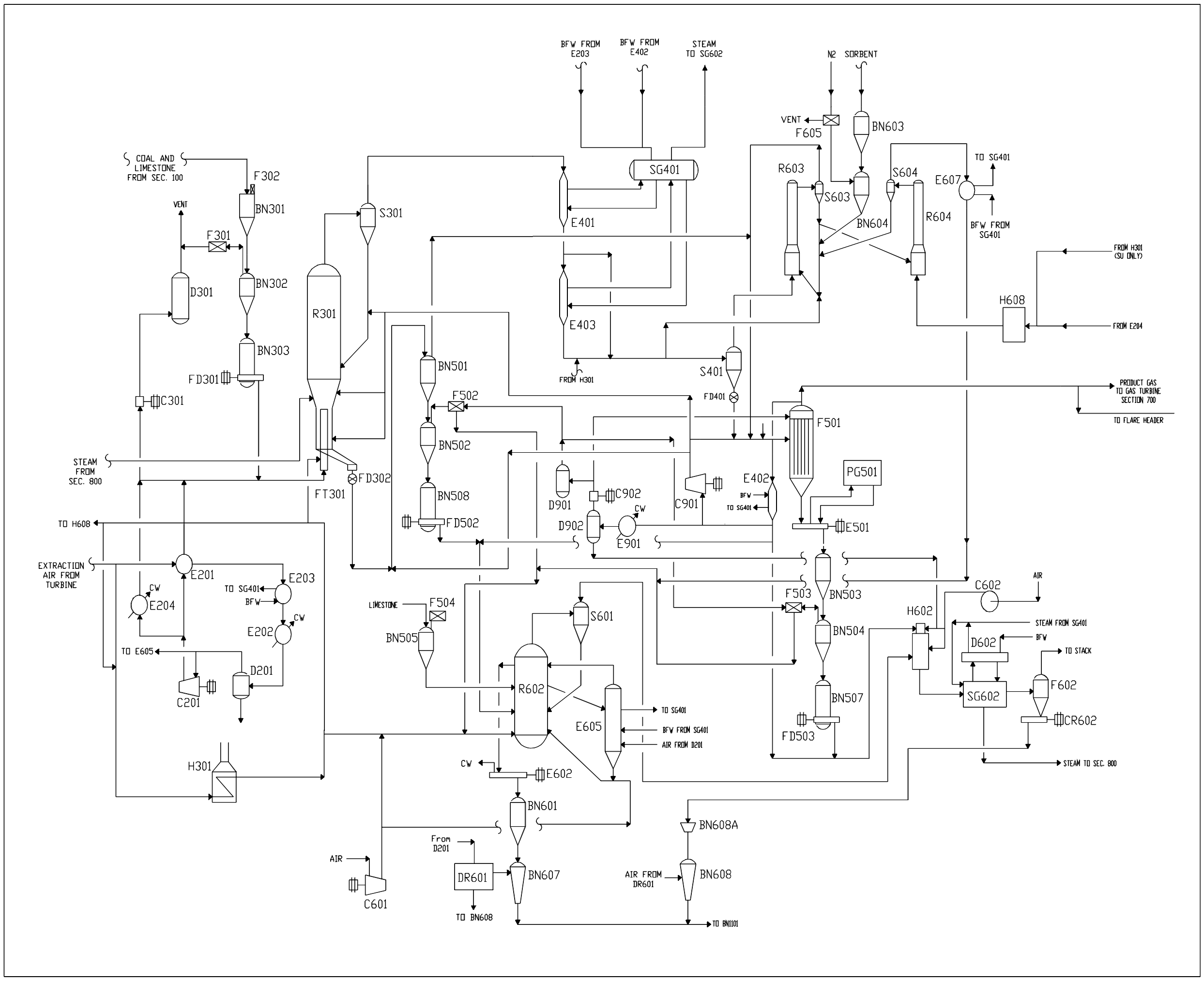


Figure 3 - Gasifier elemental flow diagram.

Clean Coal Technology has been co-funded by the Department of Energy to develop clean, efficient ways of utilizing coal to generate electricity. The Pinon Pine IGCC Project fulfills that purpose by providing a means of efficiently generating electricity from a combined cycle unit and having fewer emissions than a standard coal fired unit.

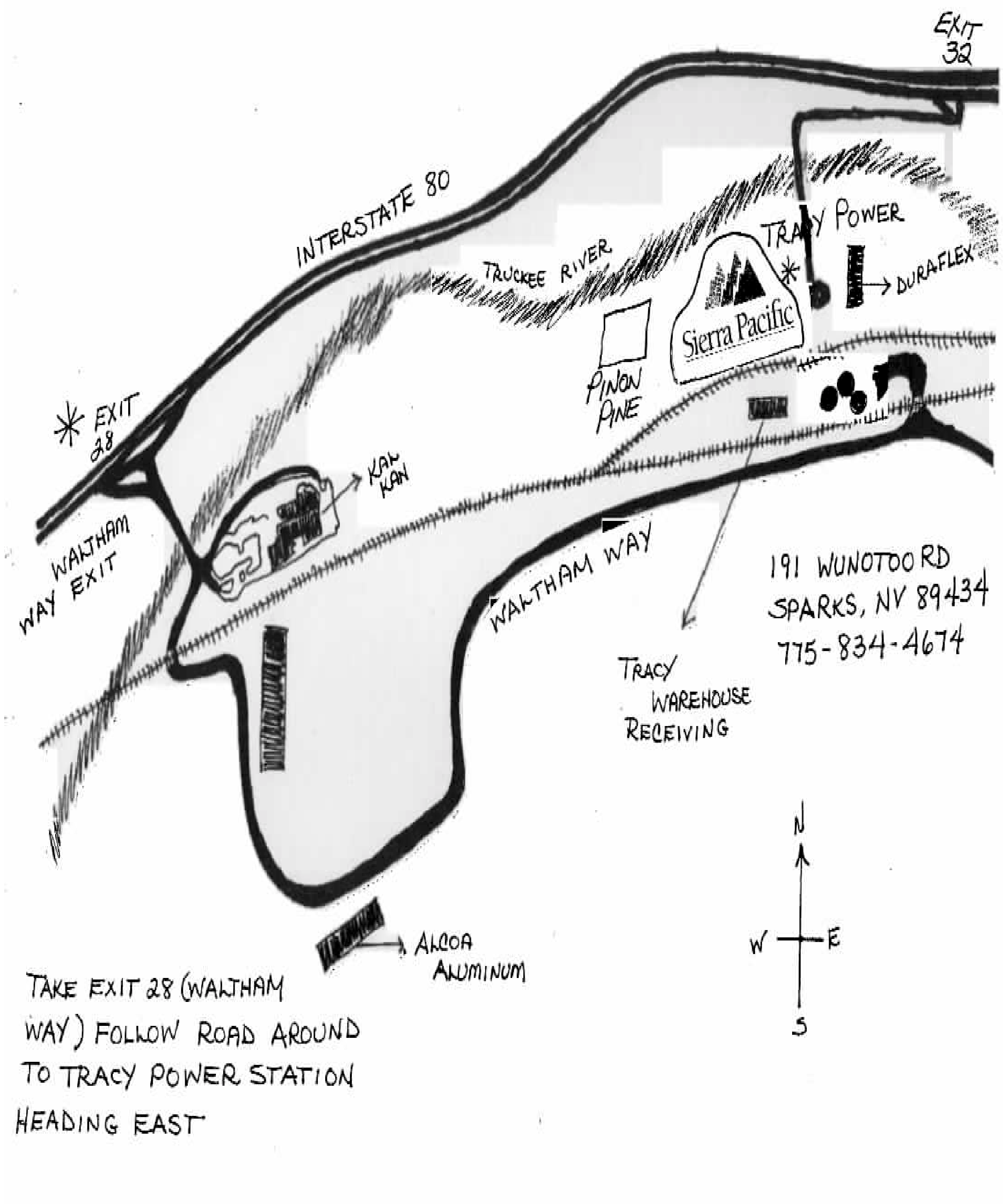
1.2 Description of Project

The purpose of the project is to prove the design and operation of the KRW air blown Gasifier and the General Electric Frame 6 combustion turbine. Both of these are the first ever to be installed as a commercial project. The KRW Gasifier utilizes air-blown technology to gasify coal for use as fuel in the GE 6FA Combustion Turbine to produce electricity. Combined Cycle design utilizes the waste heat from the combustion turbine to generate steam that produces even more electricity in the GE Steam Turbine. In addition, the processing of coal into a synthetic gas (Syngas) proves to have significantly fewer emissions than standard coal fired plants. The Clean Coal Projects started by the DOE are designed to provide generation of electricity from coal with the reduced emissions.

1.2.1 Project Location, Organization Overview & Outlook

The Pinon Pine Project is located at the Tracy Generating Station, which is 16 miles East Reno/Sparks, Nevada on Interstate 80. Take Exit 32 on the freeway and follow the frontage road to the plant. Any vehicle that weighs more than 10,000 pounds gross must take the Exit 28 location at Waltham Way. The entry bridge on the regular entrance was damaged due to flooding. Figure 4 shows a map to the facility.

Figure 4 – Map To Pinon Pine Project



The Pinon Pine IGCC Project was originally organized by representatives from the Department of Energy, Sierra Pacific Resources, M. W. Kellogg, and Foster Wheeler. The design of the Gasification portion of the plant was based on the Waltz Mill Project. This DOE sponsored project, near Waltz Mill, Pennsylvania, utilized the KRW Gasifier. The M. W. Kellogg Company has the intellectual property rights to the KRW technology and the Pinon Gasifier is a scaled-up model of the Waltz Mill unit.

Design, procurement, and construction of the entire project was the responsibility of Foster Wheeler USA Corporation, (FWUSA). The MW Kellogg Company, under subcontract to FWUSA, was responsible for design and procurement of the Gasifier Island and Hot Gas Cleanup portions of the plant. Foster Wheeler Constructors Incorporated, under subcontract to FWUSA, was responsible for construction management of the entire project.

Design and installation of the combustion turbine and steam turbine was coordinated by General Electric.

SPPCo had a Project Coordinator and Manager on-site the entire period. They had their staffs of inspectors and permit people on-site as well.

On January 1, 1996, the operations staff arrived on site for several months of formal training. The initial staffing of the Pinon IGCC unit included a Control Room Operator (CRO), Assistant Control Room Operator (ACRO), and Three (3) Service Utility Operators (SUO). This constitutes one operations crew and a total of four crews were hired. The CRO and ACRO would man the Control Room. The outside areas would be operated by the SUO. Classes were held on the turbines, the DCS control system, the Gasifier, the Clarifier, and any other pertinent operational training was conducted. Foster Wheeler Power Systems Incorporated and M. W. Kellogg personnel assisted in the training of the operations staff the initial start-up of the unit.

In October 1996, start-up of the Combined Cycle (Power Island) portion of the project was completed. Initial start-up activities on the Gasifier Island had begun. Commissioning of individual equipment and systems continued until the first start-up attempt in 1997. The start-up failed, along with subsequent attempts. The position of Gasifier Process Specialist was formed to oversee the start-up of the Gasifier on July 1, 1998. Contractor personnel supplemented SPPCo staff. All start-ups efforts from this date are documented in the reports of Sections 2 and 3.

The current organization of the facility consists of a Plant Manager, Operations Superintendent, Maintenance Superintendent, Gasifier Team Leader, Shift Team Leader, Operators, Electricians, Instrument Technicians, and Mechanics.

In 1999, Sierra Pacific Resources merged with Nevada Power Company. As a condition of the merger and as a result of ongoing restructuring of the electric utility industry, SPPCo. Is required to sell its generating assets. The Pinon plant is currently being divested. Further start-up activities have been suspended pending arrangements with the new owner.

1.2.2 Project Participants

SPPCo., the project participant, entered into a contract with the Foster Wheeler USA Corporation (FWUSA) for the overall project management, engineering, procurement and construction of the Project. FWUSA in turn subcontracted with the MW Kellogg Company (MWK) for the engineering and procurement of key components for the Gasifier Island and with Foster Wheeler Constructors, Inc. for construction management services. Foster Wheeler Power Systems was subcontracted through the FWUSA Contract to provide start-up assistance.

SPPCo. is the chief operating subsidiary of Sierra Pacific Resources, an investor-owned corporation with operating subsidiaries engaged in energy and utility services businesses. Headquartered in Reno, Nevada, SPPCo. provides electric service to 278,000 customers in a 50,000 square mile region of northern Nevada and in the Lake Tahoe area of California. SPPCo. also provides natural gas service to 95,000 customers and water service to 63,000 customers in the Reno-Sparks area of Nevada.

Foster Wheeler Corporation (FW), the parent of FWUSA and FWCI is an international organization providing engineering services and products to a broad range of industries, including the petroleum and gas, petrochemical, pharmaceutical, chemical processing, and power generation industries. These services include design, engineering, construction, project development and management, research, plant operations, and environmental services. FWUSA and FWCI are part of the Engineering and Construction Group of FW. Power Systems Group consists of a holding company, Foster Wheeler Power Systems, Inc, and a number of special-purpose subsidiaries.

The MW Kellogg Company (MWK), a wholly-owned subsidiary of Dresser Industries Inc., offers a wide range of services to both the upstream and downstream sectors of the hydrocarbon energy industry – from wellhead through refining and gas processing. Headquartered in Houston, MWK has subsidiaries worldwide. Together, they provide a full spectrum of design, engineering, procurement, construction, and project management and execution services in the international market. MWK provided certain design, engineering and procurement services for the coal gasification portion of the Project.

The DOE is entrusted to enhance the national welfare by providing the technical information and scientific and educational foundation for technology, policy, and institutional leadership necessary to achieve efficiency in energy use, diversity in energy sources, a more productive and competitive economy, improved environmental quality, and a secure national defense. The Office of Fossil Energy manages a national technology program to increase natural gas and petroleum supplies and to provide cleaner, more efficient ways to use coal and natural gas to generate electricity.

1.2.3 The Clean Coal Technology Program and Funding

The Project is funded by SPPCo., but with considerable funding assistance from the federal government, through the DOE‘s Clean Coal Technology Program.

1.2.3.1 The Clean Coal Technology Program in General

The Clean Coal Technology Program (CCT) is congressionally authorized and designed to encourage development of technologies that will enable coal to continue to be the major contributor to the nation’s energy supply mix, provide the base for the nation’s leadership in world energy production, and assist the country in achieving environmental objectives.

The CCT program was intended by Congress to create a technology base that will enable the nation to meet its energy and environmental goals efficiently and reliably. Demonstrations of new technologies are being conducted at commercial scale, in actual user environments, and under conditions typical of commercial operations.

The CCT program was implemented through a series of five nationwide competitive solicitations conducted over a 9-year period. The Pinon Pine Integrated Combined Cycle Coal Gasification project was selected as part of the Fourth Round of Solicitations (CCT-IV). The objective of this round was to address post-2000 energy supply and demand conditions, i.e., 1). Sulfur dioxide emissions capped under the Clean Air Act Amendments of 1990; 2). Increased need for electric power; and 3). Need to alleviate concerns over global climate-change conditions that translate into a need for technologies producing very high efficiencies and extremely low emissions.

1.2.3.2 Clean Coal Technology Program Authorization & Implementation

The legislation authorizing the CCT program is found in Public Law 98-473, Joint Resolution Making Continuing Appropriations for Fiscal Year 1985 and for other Purposes. Title I of that Act set aside $750 million of the congressionally rescinded $5.375 billion of the Synthetic Fuels Corporation for a special US Treasury account entitled the “Clean Coal Technology Reserve”. This account was dedicated to “conducting cost-shared clean coal technology projects for the construction and operation of facilities to demonstrate the feasibility of future commercial applications of such technology”. Title III of the Act directed the Secretary of Energy to solicit statements of interest in, and proposals for, clean coal projects. Following an initial program announcement Congress passed Public Law 99-190 in December 1985 appropriating $400 million for cost-shared projects to be selected through a competitive solicitation, or Program Opportunity Notice (PON), referred to as CCT-I. Subsequent appropriations funded CCT-II and CCT-III.

In the Department of the Interior and Related Agencies Appropriation Act of 1990 (Public Law 101-121, enacted October 23, 1989), Congress provided $600 million for the CCT-IV solicitation. This was the solicitation under which the Pinon Pine

IGCC project was selected. CCT-IV, according to the act, "shall demonstrate technologies capable of replacing, retrofitting, or repowering existing facilities and shall be subject to all provisos contained under this head in Public Laws 99-120, 100-102, and 100-446 as amended by this act". About $563 million was made available for federal co-funding of projects selected in CCT-IV, with the remainder for the program direction and the SBIR Program.

The CCT program is government/industry collaboration governed by a set of implementation principles. These include:

- A strong and stable financial commitment exists for the life of the project.

- Demonstrations are conducted on a commercial scale in actual user environments.

- The technical agenda is determined by industry, not the government.

- Roles of government and industry are clearly defined.

- Cost sharing is required throughout all project phases, and a minimum of 50% private industry funding is required.

- Repayment of the government funds is required of the industrial participant.

- The participant, in this case SPPCo., has primary responsibility for the project.

- The federal government monitors project activities, provides technical advice, assesses progress by periodically reviewing performance with the participant, and participates in decision making at major project junctures negotiated into the cooperative agreement.

1.2.3.3 CCT Funding for Pinon Pine Project-General Provisions

The federal government provided financial assistance to SPPCo. for the project in the form of a "Cooperative Agreement". A Cooperative Agreement is similar to a grant, but provides for continued involvement on the part of the DOE. The cost-sharing requirement, as implemented in the CCT program, was introduced in Public Law 99-190, An Act Making Appropriations for the Department of the Interior and Related Agencies for the Fiscal Year Ending September 30, 1986 and for Other Purposes. General Provisions related to funding of CCT projects include the following:

- The federal government's contribution cannot exceed 50% of the total cost of any individual project.

- Cost sharing by the project participants is required throughout the project (design, construction and operation).

- The federal government may share in project cost growth up to 25% of the originally negotiated government share of the project.

- The participant's cost-sharing contribution must occur as project expenses are incurred and cannot be offset or delayed based on prospective project revenues, proceeds or royalties.

- DOE's policy objective is to recover an amount up to the government's financial contribution to each project. Pursuant to this objective, SPPCo. entered into a "Repayment Agreement" with DOE and has flowed down certain repayment obligations to FWUSA and MWK.

1.2.3.4 Government Funding of Pinon Pine Project

Terms for the provisions of funding to SPPCo., and ultimate repayment to DOE, are contained in the Cooperative Agreement and the Repayment Agreement. The "Notices of Financial Assistance Award" summarize project funding.

As originally negotiated with DOE in mid-1992, the total estimated cost of the project was $269,993,100 (construction cost plus 42 months of O&M and fuel cost). Subsequent to preparation of the so-called "Definitive Cost Estimate" in late 1994, SPPCo. requested approval to construct from DOE. In January, 1995, DOE issued the approval to construct with a revised total project cost of $308,551,000.

1.2.4 Project History: Evolution, Design, Permitting & Construction

1.2.4.1 Project Inception – Early 1991

SPPCo's involvement with this project dates back to February 1991 when SPPCo. was contacted by FWUSA. FWUSA outlined a concept for making a proposal to DOE for an IGCC project. The basis of the concept involved making application to DOE pursuant to CCT round IV for federal co-funding of the project.

Within a few days of the initial phone call, FWUSA and MWK met with SPPCo. to present additional details of the project and determine if there was any interest. As SPPCo. expected to have a need for additional power over a period of several years, the concept was of potential interest.

Following the initial meeting, SPPCO. conducted due diligence and economic modeling. To be approved by SPPCo's management, the project had to be technically feasible, limit the risks associated with new technology, and most importantly, be the "Least Cost" generation resource available. Nevada is governed by Resource Planning Statutes, which require that cost be the primary selection criterion for any proposed power generation plan.

At the conclusion of preliminary due diligence, SPPCO. management approved teaming with FWUSA and MWK to develop and submit a proposal to DOE in May, 1991. The proposal cost was not to exceed $50,000.

1.2.4.2 Proposal to DOE – Selection of Project & Negotiations

The Project proposal was submitted to DOE on May 1, 1991, which was the deadline for submittals under CCT-IV. In September 1991 SPPCO. was notified that the project had been "selected for negotiations". The negotiations were successfully concluded by May 1992. Following the required "Comprehensive Report to Congress" on the project (filed in June 1992), the DOE executed the Cooperative Agreement on 7/31/92.

The Cooperative Agreement contemplated three phases: (1) permitting/design and engineering; (2) construction; and (3) operations. There was a time overlap between 1 & 2. Commitments were made by "Budget Period", and the total estimated cost of the project was $269,993,100 (including the 42 month Operations Phase). The Cooperative Agreement contained a schedule, which envisioned start of Operations on synthetic gas production by February 1, 1997.

1.2.4.3 Environmental Studies, Regulatory Status, Project Design and Engineering

Between mid 1992 and late 1994 extensive environmental studies were conducted. These culminated in a favorable Environmental Impact Statement in November 1994. Additionally, SPPCO. received from the Nevada Public Service Commission full Resource Planning Approval for the project as part of its "Preferred Resource Plan" in September 1994.

SPPCO. and FWUSA signed the Contract for engineering and construction management effective August 1, 1992. FWUSA, in turn, subcontracted the Gasifier design to MWK. Design was completed (including a selection of a different gas turbine and a revised desulfurization system), engineering was ongoing, limited procurement was undertaken, and costs were being refined as of late 1994.

In December 1994 FWUSA finalized the "Definitive Cost Estimate". This cost estimate, with an expected accuracy of +/- 10% was the basis for SPPCo. management's approval to proceed to construction and for the "Budget Period 2 (Construction)" request to DOE. This estimate envisioned an overall construction cost of $222 million, with a FWUSA-controllable scope totaling $208 million. DOE approved the Budget Period 2 Continuation Request on January 18, 1995, and raised the total award value for construction and operation from approximately $270 million to approximately $308.5 million.

1.2.5 Construction

1.2.5.1 Approach

As part of the Construction Work Plan, Foster Wheeler USA implemented a contract delivery approach where some components and equipment were "Design / Build", and all other major areas of the work were broken down into separate bid packages. All D&E and bid package contractors would have unique contracts with SPPCo (FWUSA acted as "owner agent"). Select specialty contractors would perform some of the work on a Design Build basis, and, as "experts" in a particular field, would be able to perform at lower cost than the traditional "design, bid, and construct" approach. The respective D&E and contractors were not required to coordinate with each other, or have overall management responsibility of the project. This delivery approach required a Construction Manager (FWCI) to coordinate and manage the work. The overall approach was intended to allow greater control of subcontractors' costs because designs would be completed and work packages awarded on a phased basis.

1.2.5.2 Breakdown of Major Components of the Work

The following is a breakdown of the major D&E and construction subcontracts:

- Foundations & Underground
- Site Preparation
- Structural Steel / Gasifier Mechanical & Piping
- Combined Cycle Mechanical & Piping
- Electrical & Instrumentation
- Gas Turbine & Steam Turbine
- Gasifier Vessel
- Coal Storage Dome
- Stacker / Reclaimer
- Coal Handling Equipment

- Cooling Towers
- Nitrogen Plant
- Flue Gas Stack
- Refractory
- Distributed Control System
- Heat Recovery Steam Generator

1.2.5.3 Steps Put in Place to Manage and Control Cost and Schedule

The following is a high level overview of some of the processes, tools and approaches used by FWUSA, MWK and SPPCo. to manage and control project cost and schedule:

- ***Third Party Peer and Oversight Reviews:***
  This action by SPPCo is defined as retaining independent third-party consultants engaged in a specific area of expertise, and render independent opinions for: design status; design reasonableness; project cost/project schedule/project management efforts and accuracy; and course-of-construction cost/schedule updates.

- ***Value Engineering Program:***
  Value Engineering is defined as an organized effort to analyze the function of systems, equipment, facilities, procedures and supplies by a multi-disciplined group for the purpose of achieving the required function at the lowest total cost.

- ***Project Management Plan, Construction Execution Plan and Subcontracting Plan:***

The Project Management Plan, Construction Execution Plan and Subcontracting Plan are defined as a comprehensive set of programs, guides and outlines of how the participants planned on managing, controlling and monitoring the cost, design, procurement and construction progress of the project.

The Project Management Plan, Construction Execution Plan and Subcontracting Plan are significant because the development of these documents allowed the participants to discuss and agree on systems and approaches before the work started, as all of these documents called for early input and discussion. DOE required the development and implementation of these documents, and approved these documents. It can be thus be reasonably inferred that DOE believed Foster Wheeler planned to use appropriate and correct tools, systems and methodologies to adequately control project design, construction and costs.

- ***Pre-qualified Vendors, Contractors, and Suppliers:***

  Pre-qualified Vendors, Contractors, & Suppliers is defined as a program to qualify all firms who provide labor, equipment, materials, and expertise to the project to ensure the selected firms have the requisite experience, insurance coverage, financial stability and staffing to complete their portion of the work.

- ***Utilized a Fully Staffed Construction Manager:***

  A fully staffed construction manager is defined as an entity mobilized in the field responsible for subcontractor selection; managing the subcontractor bidding process; subcontractor contract management; managing / facilitating / coordinating field construction efforts; coordinating design issues with vendors, suppliers, FWUSA and

MWK; ensuring quality control / assurance; coordinating deliveries, cranes / manlifts / major equipment; and mitigating / resolving construction disputes.

The significance of a CM is that a professional services firm whose primary business is management (as opposed to a general contractor) is hired to be responsible for all aspects of management. SPPCo agreed with the use of FWCI instead of a third party CM in the belief that as a subsidiary of a project participant, FWCI's primary focus would be the success of the project.

- ***Fixed Pricing on Key Equipment and Materials Prior To Bid Package Bidding:***

Fixed Pricing on Key Equipment and Materials Prior To Bid Package Bidding is defined as having "pricing and specifications in hand" prior to bidding work that utilized the equipment or materials.

This approach is significant because it (1) ensures that most materials would be provided by bulk purchases in lieu of being "subcontractor supplied", (2) eliminates duplicative material submittal reviews (for same materials provided by different contractors), (3)eliminates "or/equal" issues during construction, (4) obtains highest quantity discounts and lowest delivery charges, (5) eliminates subcontractors' markups/fees on pass through equipment and materials. Additionally, with specific vendors and materials "in hand", bidding contractors would have a clearer definition of scope, quality and definition of the work (and these should yield more competitive pricing).

- ***Monthly Detailed Cost and Progress Reporting:***

Monthly Detailed Cost and Progress Reporting is defined as Monthly reports (March 1994 to date), which included schedule, cost status, progress, and forecasts. These reports were prepared by Foster Wheeler and MW Kellogg and submitted to SPPCo.

The significance of these reports is that they provided SPPCo with current and forecast status of the project and ensured that the FWUSA/MWK design team and the CM tracked and reviewed project cost and schedule each month, and recognized/incorporate trending into project forecasts. The reports also established a comprehensive project record of costs and schedule progress.

- ***Mobilized a Field Owner's Management and Accounting Team:***

  A Field Owner's Management and Accounting Team is defined as a Owner's staff of construction managers, engineering managers, project managers, quality control monitors, and accountants assigned to the field, and interfaced daily with FWUSA, FWCI & MWK.

  The significance of this team of highly qualified professionals, is that they interacted on a daily basis with FWUSA, FWCI, FWPS, and MWK. Direct daily interaction reduced lead time for SPPCo review / approval; allowed for timely responses on "Q&A" accounting, procedural, and logistics issues between SPPCo and FWUSA / FWCI / MWK; and provided a visible presence to FWUSA, FWCI, FWPS, MWK and DOE of SPPCo's dedication and commitment to the project.

- ***Project Labor Agreement:***

  Project Labor Agreement is defined as an agreement entered into by SPPCo and the local Building Trades (Unions) which established craft labor rates, overtime procedures, and escalation rates for all labor employed on site during the project.

Significant aspects of the agreement include; (1) work slowdowns and strikes were specifically disallowed, (2) established standards for premium time rates (i.e. no premium for hours in excess of 8 hrs/day, as long as weekly total doesn't exceed 40 hrs), (3) established standard rates for all craft classifications to all site contractors (i.e. no need to re-negotiate labor rates with each individual contractor), (4) eliminated travel and subsistence expenses, and etc.

- ***"STOP" Safety Program:***

  STOP safety program is defined as a **"** "Safety Training Observation Program" with a proactive approach to safety aimed at to raising safety awareness, and thereby reduce accidents.

  The significance of this program is that it is an effective method to control injury/accident rates during the construction / start-up phase of the project. As a result of this program, nearly two million man hours were worked without a single lost time accident, resulting in overall good project moral, higher productivity, and ultimately, lower project costs. SPPCo was awarded the "Freedom Award" by ESIS (and Insurance Services Company) in recognition of the outstanding safety record.

- ***Zero Tolerance Drug Free Work Place Program:***

  Zero Tolerance Drug Free Work Place Program is defined as an approach whereby all craft labor and site management personnel underwent drug testing. All persons who failed drug test were barred from working on the project.

  This program is significant because it contributed to the project's exemplary safety record, and the positive safety record boosted morale among the work force.

- ***Monthly Project Review Meeting:***

  Monthly Project Review Meeting is defined as a series of monthly meetings held between Foster Wheeler, MWK and SPPCo to discuss project history, project forecasts, problem areas, and problem resolutions**.**

  These meetings were significant because they allowed Foster Wheeler, MWK and SPPCo to sit down each month and collectively work through issues and problems. This allows for expedited and constructive "hands on" resolution of problems.

- ***Owner / Vendor Meetings On Critical Items:***

  Owner / Vendor Meetings On Critical Items is defined as direct meetings between SPPCo and Vendors on critical components of the project.

  These meetings were significant because direct meetings allowed SPPCo to stress the importance and visibility of the Project and thereby expedite procurement.

- ***Periodic meetings with building trades***

  Periodic meetings with the building trades is defined as numerous meetings between SPPCo and union business agents to review productivity, labor force effectiveness, and commitment to the project.

  These meetings were significant because the project experienced difficulty with maintaining union craft labor staffing levels due to a very competitive construction market drawing personnel to California and elsewhere. These meetings allowed the local union officials to recognize the importance of the project, and SPPCo's commitment to the project.

- ***Craft labor morale boosting strategies:***

  Craft Labor Morale Boosting Strategies is defined as a program to boost craft labor morale by providing safety awards, jackets, hats and lunches for the craft labor force at key milestones during the project.

The significance of this program is that it enhanced craft labor personnel's commitment to the project, and thereby boosted attitude, productivity and safety.

1.2.6 Construction Progress

Key construction progress dates are as follows:

Start Site Preparation & Mass Excavation:	February 13, 1995
Start Foundations	June 12, 1995
Start Structural Steel / Piping	November 14, 1995
Start Electrical & Instrumentation	March 4, 1996
Complete Cooling Tower	March 29, 1996
Set Gasifier Vessel	January 11, 1996
Construction 25% Complete	January 1996
Set Gas Turbine	March 26, 1996
Construction 50% Complete	April 1996
Complete Structural Steel/Set Equipment	April 26, 1996
Complete HRSG	May 10, 1996
Complete Silos	May 31, 1996
Construction 75% Complete	June 1996
Combined Cycle Mechanically Complete	July 31, 1996
Complete Waste Evaporation Tower	August 9, 1996
Gas Turbine First Fire	August 15, 1996
Gas Turbine Commercialized	December 1, 1996
Gasifier Mechanically Complete	April 1, 1997

1.2.7 Pictures

Figure 5 - Excavation and construction of underground conveyor system.

Figure 6 - Beginning of steel erection and setting vessels.

Figure 7 - Gasifier steel erection continues.

Figure 8 - Gasifier start-up heater.

Figure 9 - Steel erection.

Figure 10 - Combustion turbine inlet to HRSG.

Figure 11 - Overview – Cooling tower, coal dome, silos.


Figure 12 – Pipe Rack

Figure 13 - Gasifier structure – looking from SW.

Figure 14 - Cooling tower, coal crusher tower, silos, Gasifier structure.

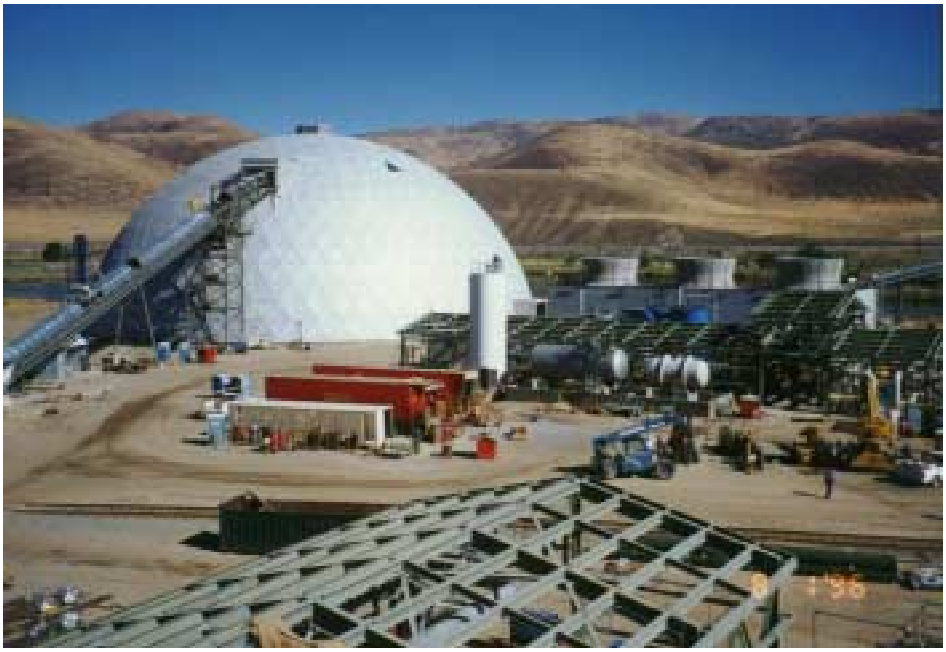


Figure 15 - Coal storage dome.

Figure 16 - Nitrogen plant.

Figure 17 - Coal crusher tower and silos.

Figure 18- Coal train unloading facility.

Figure 19 - Gasifier structure – looking from SE.

2.0 Project Summary

2.1 Process Concept

The Pinon Pine Power Project is one of the Clean Coal Technology projects selected by the United States Department of Energy in round IV of the Clean Coal Technology Program. Unit 4 at the Tracy Power Station is the first commercial size Kellogg-Rust-Westinghouse (KRW) coal gasification process to produce clean product gas (fuel gas) and steam which are used to generate electrical power. The design of the Gasifier Island is based on heat and material balances which reflect the full load fuel demand of a General Electric Gas Turbine (Frame 6FA) at 50°F ambient temperature.

The design coal (SUFCO) is a Southern Utah bituminous coal. The “as received” coal will contain approximately 10% total weight in moisture and its composition is 70% to 80% carbon. The Gasifier Island has the capacity to process about 885 tons of coal feed per day. The low BTU product gas produced by the Gasifier Island is delivered to a gas-fired turbine, which is directly coupled to a generator. The gasification process will deliver a daily quantity of the low BTU product gas sufficient to generate 99 megawatts net electricity. The gas turbine also produces exhaust heat, which is used to generate steam. The steam is used to drive a steam turbine generator and produce electrical power.

The Gasifier Island also includes provisions for removing sulfur compounds from the product gas. Desulfurization is accomplished by a combination of first injecting limestone into the fluidized Gasifier bed and secondly passing the product gas through a Transport Desulfurizer. Particulate removal is also achieved by passing the product gas through high efficiency cyclones and barrier filters.

Air extracted from the Combustion Turbine will supply the process air requirements for operation of the Gasifier Island. The extraction air will be cooled and compressed to a higher pressure inside the battery limits of the Gasifier Island. Spent limestone, coal ash, and calcium sulfate will be cooled and then discharged to disposal facilities outside the battery limits. The Combined Cycle section (Power Island) will supply boiler feedwater, steam, cooling water, instrument air, plant air, nitrogen and electric power to the Gasifier Island as required. Steam generated in the Gasifier Island is exported to the Power Island.

Air is extracted from the combustion turbine to supply the requirements of the Gasifier Island. Heat exchangers and compressors then cool and compress the air to satisfy the requirements of the following processes:

- Air to the Gasifier
- Air to regenerate the Desulfurizer sorbent
- Pressurization and transport air for the Coal and Limestone Feed Systems
- Fluidization for Primary Solids Cooler
- Transport of waste solids from the Gasifier Island to Waste Silo

The Boost Air Compressor increases the pressure of the extraction air to satisfy the process requirements of the Gasifier. Process requirements are dictated by the demand of the combustion turbine. It also sends air to the Sorbent Regeneration Air Heater and to the Pressurization Air Compressor for the Coal Feed System.

Coal and limestone are fed to the Gasifier via the Coal Feed System. A single conveyor dumps the product into the Atmospheric Feed Surge Bin. It then dumps into Feed Pressurization Bin, which pressurizes to Gasifier pressure and dumps into Feed Bin. From there, the Coal Feeder regulates the transfer of solids into the transfer line where air conveys the product to the Feed Tube inside the Gasifier. Combustion of the fuel occurs at the outlet of the Feed Tube by means of hot air mixing with the fuel from the Combustion Air Line.

Gasification involves the reaction of steam and carbon dioxide with carbon to produce hydrogen and carbon oxides. Gasification reactions are endothermic (requiring heat input) while oxidation reactions are exothermic (heat producing). In the Gasifier, air reacts with coal and volatiles to form carbon oxides and the reaction provides the heat required for gasification.

Carbon monoxide and hydrogen are the principle components of the Gasifier product gas. Methane and other hydrocarbons are produced in lesser quantities primarily from the devolatilation of the coal.

At the exit of the Feed Tube where the combustion occurs, a jet is formed from the mixing of the fuel stream and the combustion air. As the carbon in the mixture is consumed, char is formed and ash particles begin to agglomerate. The mixing of the Gasifier bed by the jet and the dissipation of the primary heat of the combustion in the jet are crucial to prevent the formation of clinkers. As the ash particles grow, they separate out of the process and fall into the annulus section of the Gasifier.

Steam and recycled Syngas are injected through multiple nozzle points into the conical section of the Gasifier to fluidize the solids around the jet to assure the proper solids circulation.

The annulus section of the Gasifier cools the limestone/ash mixture (LASH) and a Grinder and Feeder remove the LASH and dump it into a transport line. Recycled gas then transports the LASH to the Ash Collection Bin. This then dumps into the Ash Depressurization Bin which depressurizes and dumps into Ash Feed Bin. From here it is transported through Ash Feeder to the Sulfator for final processing.

Steam is produced in the Gasifier Island by four different coolers and a small Heat Recovery Steam Generator (HRSG). The four coolers are mentioned below:

- Two Product Gas Coolers cool the Syngas from 1800°F to 1000°F.
- Primary Solids Cooler cools the Sulfator.
- Regenerator Gas Cooler cools the Sulfur Dioxide regenerant gas from the Sorbent Regenerator.

Product gas exiting the top of the Gasifier contains a significant amount of entrained solids in the form of char, ash, and limestone. The Gasifier Cyclone removes all particles larger than 40 microns. A dip leg then returns the solids to the Gasifier bed. A second cyclone, the Desulfurizer Feed Cyclone removes even more of the particles before the Syngas enters the Desulfurizer.

Syngas enters the Desulfurizer and mixes with the sorbent. Sulfur products are removed from the gas and the stream exits through the Desulfurizer Cyclone. The Sorbent is returned to the Desulfurizer and Syngas travels on to the Hot Gas Filter. The spent sorbent is regenerated in the Regenerator with hot air. After it has been regenerated, it is returned to the Desulfurizer.

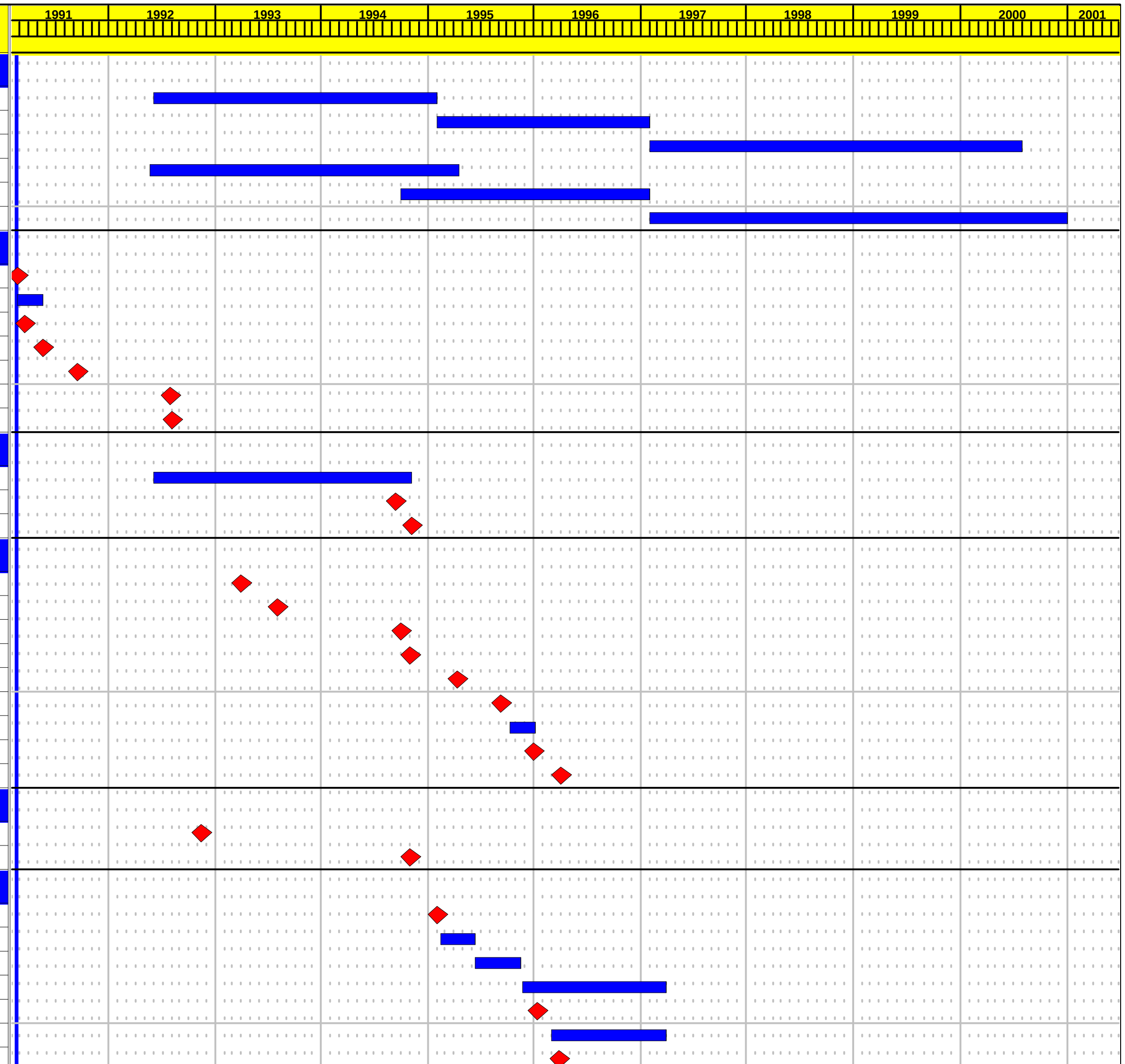
The Hot Gas Filter removes all remaining particulates from the Syngas. The stream then exits the filter and goes to the combustion turbine, Recycle Gas Compressor, or the Flare. The Recycle Gas Compressor raises the pressure of the Syngas so it can be used for fluidizing purposes in the Gasifier and Desulfurizer. The Flare burns off any excess gas that it not used in the combustion turbine.

The Fines Combustor is used to consume the fines removed from the Hot Gas Filter. Fines in the filter are collected in the cone section and the Fines Screw Cooler removes them and dumps into the Fines Collection Bin. This then dumps into the Fines Depressurization Bin which depressurizes and dumps into the Fines Feed Bin. Fines Feeder then dumps the fines into the transport line where recycle gas transports it to the Fines Combustor for incineration. Hot gases produced from this process are used to produce steam in the HRSG. The baghouse removes the particulates produced from the combustion and they are conveyed to the Waste Silo.

An off-site nitrogen generating facility produces nitrogen for start-up and inerting purposes. It also is used to purge the Flare header and purge instruments.

2.2 Construction and Start-Up Schedule

Description	Start	Finish
PROJECT PHASING		
Budget Period 1	01JUN92A	31JAN95A
Budget Period 2	01FEB95A	31JAN97A
Budget Period 3	01FEB97A	31JUL00A
Phase 1 (Design / Permitting)	20MAY92A	19APR95A
Phase 2 (Equip. Fab. / Construction / Start-Up)	30SEP94A	31JAN97A
Phase 3 (Operation / Data Collection)	01FEB97A	31DEC00A
PROJECT DEVELOPMENT		
Initial FW Approach to SPPCo	19FEB91A	
FW / SPPCo: Outlining Concept	19FEB91A	17MAY91A
SPPCo Aproval to Propose	15MAR91A	
Proposal Submitted to DOE	17MAY91A	
FW / SPPCo Selected For Negotiations	15SEP91A	
Cooperative Agreement Executed	31JUL92A	
SPPCo / FWUSA Contract Executed	01AUG92A	
PRE - DESIGN		
Environmental Studies	01JUN92A	08NOV94A
Nevada Full PSC Resource Planning Approval	12SEP94A	
Environmental Impact Statement: ROD	08NOV94A	
DESIGN / PROCUREMENT		
Design Start	01APR93A	
Procurement Start (Except Long Lead)	01AUG93A	
Develop Bid Packages	01OCT94A	
40% Design Review	01NOV94A	
Design Hazard Review: GA	15APR95A	
Design Hazard Review: CC	08SEP95A	
Design Hazard Review: Integrated	10OCT95A	03JAN96A
Procurement Prog. No Longer Reported (Complete)	31DEC95A	
Design Progess No Longer Reported (Complete)	01APR96A	
COSTS		
Planning Estimate	15NOV92A	
Definitive Estimate (Class II) $208.8 M	01NOV94A	
CONSTRUCTION		
Start Construction	01FEB95A	
Site Preparation & Mass Excavation	13FEB95A	12JUN95A
Foundations	13JUN95A	15NOV95A
Structural Steel / Piping	22NOV95A	01APR97A
Set Gasifier Vessel		11JAN96A
Electrical / Instrumentation	04MAR96A	27MAR97A
Set Gas Turbine		26MAR96A



Project Start 15FEB91
Project Finish
Data Date 15FEB91
Run Date 24OCT00

Early Bar
Progress Bar
Critical Activity

RPT1

SIERRA PACIFIC POWER COMPANY
PIÑON PINE POWER PROJECT
PROJECT OVERVIEW SUMMARY

Sheet 1 of 3

Sierra Pacific

Date	Revision	Checked	Approved

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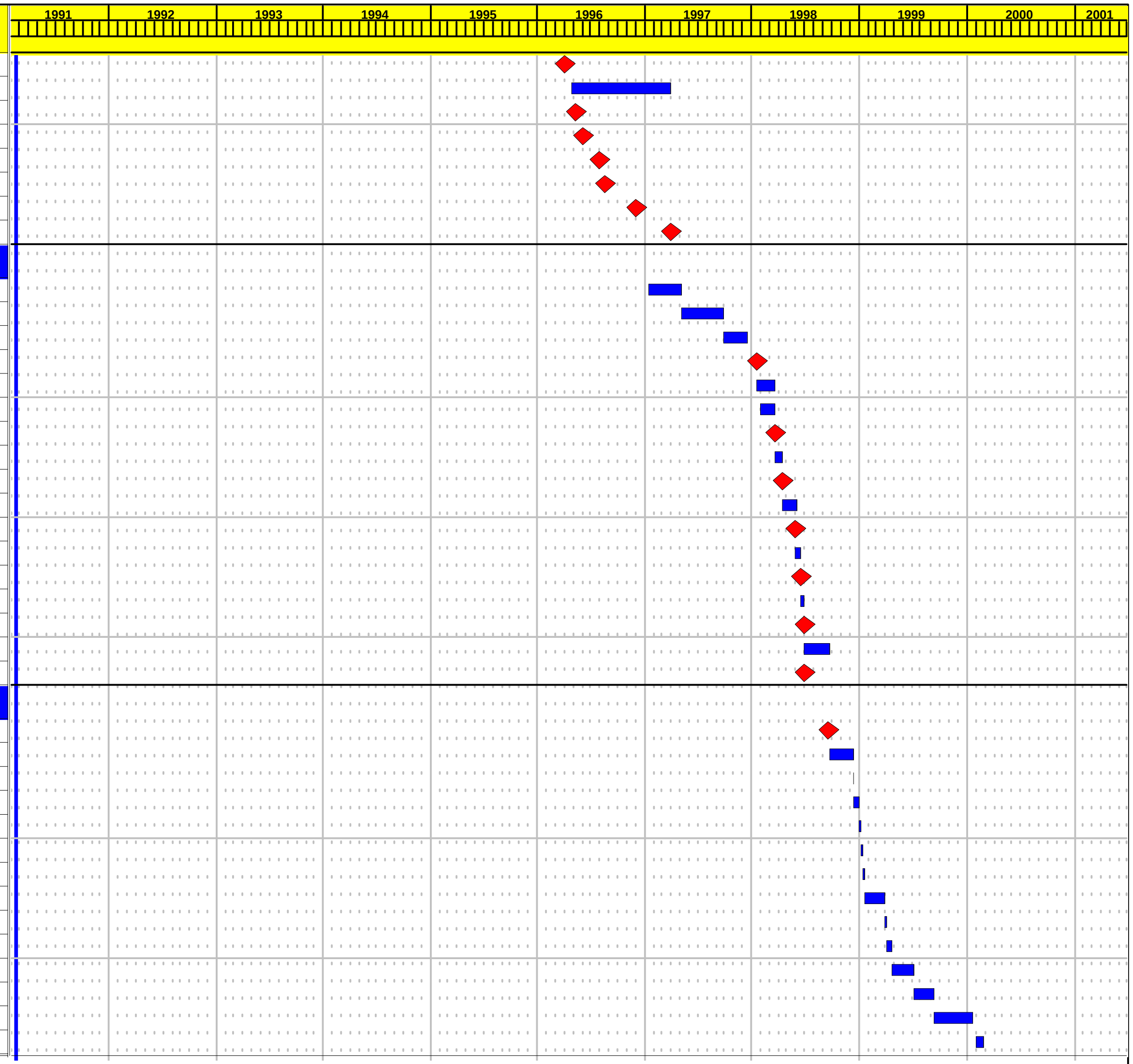
Pinon Pine Project – Final Technical Report
Section 2
2.2 Construction and Start-Up Schedule

Description	Start	Finish
Complete Cooling Tower		04APR96A
Set Equipment	26APR96A	27MAR97A
Complete HRSG		10MAY96A
Complete Silos		31MAY96A
CC Mechanically Complete	31JUL96A	
First Fire Gas Turbine	15AUG96A	
Gas Turbine Commercialized	01DEC96A	
Gasifier Mechanically Complete	31MAR97A	
PRE-COMMISSIONING START - UP		
Nitrogen Plant Issues	15JAN97A	04MAY97A
Control Logic/Overpressurization/Feed Tube	05MAY97A	30SEP97A
Flare Relocation, Phase I	01OCT97A	15DEC97A
1/19/98 Syngas Run	19JAN98A	
Stub Shafts/FD302Blades/Dome Vlv/ZSorb/Lvl Prbs	19JAN98A	20MAR98A
Flare Relocation, Phase II	30JAN98A	24MAR98A
3/20/98 Syngas Run	20MAR98A	
HTF Pump/Candles/F501/FD302 Blades/Stub Shafts	20MAR98A	17APR98A
4/17/98 Syngas Run	17APR98A	
H602/Extraction Air Line	17APR98A	02JUN98A
6/2/98 Syngas Run	02JUN98A	
HTF Pump/Candles/F501	02JUN98A	17JUN98A
6/17/98 Syngas Run	17JUN98A	
PG503 Level Probes	17JUN98A	30JUN98A
6/30/98 Syngas Run	30JUN98A	
HG Filter/Level Probes/Fines Combustor	30JUN98A	22SEP98A
GASIFIER COMMERCIALIZED	30JUN98A	
POST-COMMISSIONING START-UP		
Gasifier Start-Up #1	22SEP98A	
Gasifier Outage #1	23SEP98A	15DEC98A
Gasifier Start-Up #2	16DEC98A	17DEC98A
Shut Down Period #2	18DEC98A	31DEC98A
Gasifier Start-Up #3	01JAN99A	07JAN99A
Shut Down Period	12JAN99A	17JAN99A
Gasifier Start-Up #4	18JAN99A	19JAN99A
Gasifier Outage #2	22JAN99A	30MAR99A
Gasifier Start-Up #5	31MAR99A	06APR99A
Gasifier Start-Up #6	07APR99A	27APR99A
Gasifier Outage #3	29APR99A	09JUL99A
Gasifier Start-Ups #7,8,9,10	12JUL99A	09SEP99A
Gasifier Outage #4	10SEP99A	21JAN00A
Gasifier Start-Ups #11,12,13,14,15,16,17	04FEB00A	25FEB00A



Project Start	15FEB91	Early Bar	
Project Finish		Progress Bar	
Data Date	15FEB91	Critical Activity	
Run Date	24OCT00		

RPT1

Sheet 2 of 3

SIERRA PACIFIC POWER COMPANY
PIÑON PINE POWER PROJECT
PROJECT OVERVIEW SUMMARY

Date	Revision	Checked	Approved

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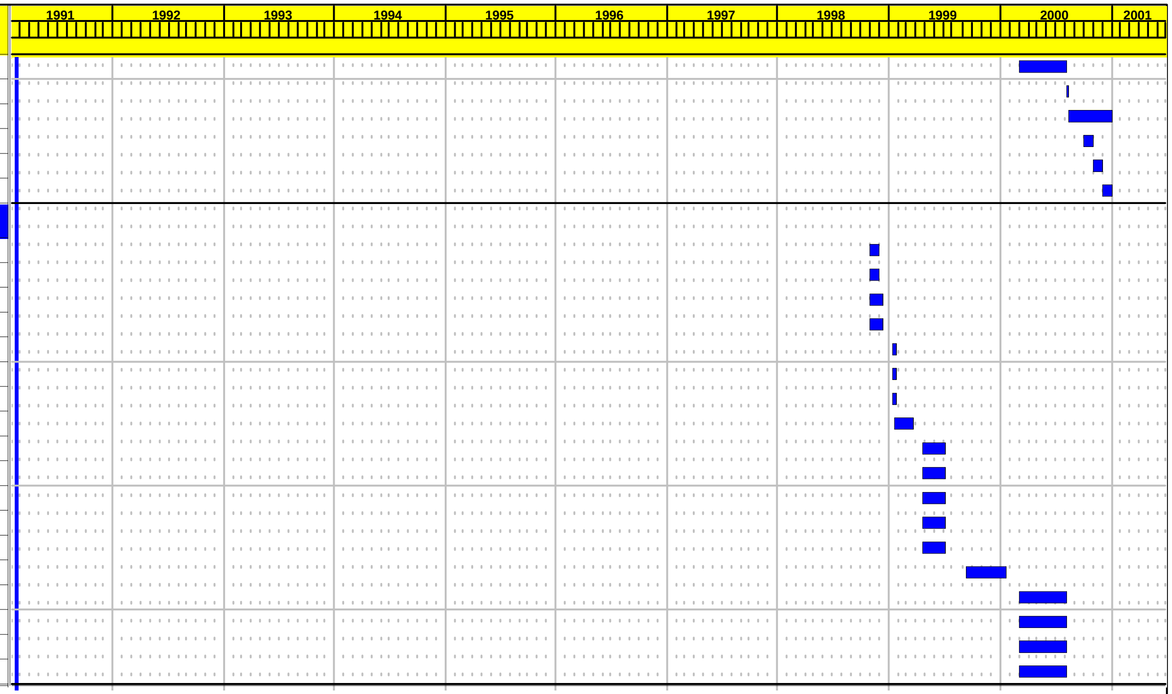
Pinon Pine Project – Final Technical Report
Section 2
2.2 Construction and Start-Up Schedule

Description	Start	Finish
Gasifier Outage #5	01MAR00A	07AUG00A
Gasifier Start-Up #18	08AUG00A	11AUG00A
Gasifier Outage #6	14AUG00A	01JAN01A
Final Technical Report	01OCT00A	01NOV00A
DOE Report Review	01NOV00A	01DEC00A
Final Report Completed	01DEC00A	01JAN01A
POST COMMISSIONING CAPITAL IMPROVEMENTS		
Nuclear Level Gages	01NOV98A	04DEC98A
Fines Combustor Ignitors	01NOV98A	04DEC98A
Nozzle Modifications	01NOV98A	15DEC98A
Filter Fines Removal Package Improvements	01NOV98A	15DEC98A
Fines Combustor Thermocouples	17JAN99A	25JAN99A
Fines Combustor Expansion Joint	17JAN99A	25JAN99A
Combustion Air Line Thermocouples	17JAN99A	25JAN99A
Filter Fines Removal Package Improvements	22JAN99A	24MAR99A
Filter Fines Diversion Line	29APR99A	08JUL99A
Filter Fines Removal Package Improvements	29APR99A	08JUL99A
Fines Combustor Assist Burners	29APR99A	08JUL99A
Grit Vessels Beneath HRSG	29APR99A	09JUL99A
Gasifier Central Vacuum Line	29APR99A	09JUL99A
Filter Fines Removal Package Requirements	10SEP99A	21JAN00A
Redesign Gasifier Nozzles	01MAR00A	07AUG00A
Annulus Refractory	01MAR00A	07AUG00A
Filter Fines Removal Package Improvements	01MAR00A	07AUG00A
Gasifier Refractory	01MAR00A	07AUG00A



Project Start	15FEB91	Early Bar	RPT1
Project Finish		Progress Bar	Sheet 3 of 3
Data Date	15FEB91	Critical Activity	
Run Date	24OCT00		

SIERRA PACIFIC POWER COMPANY
PIÑON PINE POWER PROJECT
PROJECT OVERVIEW SUMMARY

Date	Revision	Checked	Approved

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2.3 Monthly Reports

2.3.1 GASIFIER MONTHLY REPORT FOR THE MONTH OF: November, 1998

The Gasifier has been down the entire month for repairs and redesign. The list of repairs and redesign is covered in the Gasifier outage work list. The status of the work to date is as follows:

- The bottom of the Gasifier will return from repair shop on or about Thursday, December 3, 1998. At that time, installation will begin. It is estimated to take ten working days to put it back together.
- The refractory damage has been repaired and is waiting final inspection.
- Operators will be rodding out instrument taps and clearing nozzles during the next two weeks
- The Grinder seals are installed and the grinder will be replaced once the bottom of the Gasifier is assembled.
- The nuclear level gages are in place and being commissioned December 1 – 4.
- The seismic particle detector for the Syngas line is being designed.
- We are awaiting four metal filters for installation in the Hot Gas Filter. All the ceramic filters are now in place.
- The leak in the Sulfator Solids Screw Cooler is being repaired.
- New ignitor guns will be installed in the Fines Combustor. This will provide flame stability for the next start-up.

- Welding of the flange onto the bottom of Sulfator J-Leg will occur this week.

- Vendor will be on site December 3 – 4 to perform required maintenance on the nitrogen plant. There will be mechanic training during this period also.

- Several insulation jobs are in progress.

The projected date for the next start-up attempt is December 15, 1998. At this time the objective of the Gasifier run will be to evaluate the solutions implemented to THE BIG 3 issues that appeared during the last start-up and to progress onto Sulfator/Desulferizer/Regenerator operation. A fuel swap in the turbine is not expected until this goal is achieved along with installation of the seismic probe in the Syngas line. GE also recommends that we have 60 hours of stable operation in the Gasifier.

2.3.2 GASIFIER MONTHLY REPORT FOR THE MONTH OF: December, 1998

The Gasifier was shut down for repairs the first fifteen (15) days of December. The following list of items were completed:

- The expansion joint between Fines Combustor and Heat Recovery Steam Generator was replaced. It had blown out.

- The bottom of Gasifier was removed and sent to the shop to have repairs made to Feed Tube Assembly. It was received on site on 12/8/98 and put back into place.

- The damaged refractory in Gasifier was repaired by contractor.

- All vessels were emptied and inspected for damage.

- The combustion air line was borescoped and UT measurements were made on the wall thickness.

- New packing type seals were installed in Grinder. The previous mechanical seals had failed.

- Gasifier steam ring modifications were made to the nozzles. We had no way to isolate and clean them.

- Nuclear level detectors were installed in Filter Fines Collection Bin, Filter Fines Depressurization Bin, and Hot Gas Filter. Vibration level detectors were installed in Filter Fines Feed Bin.

- The nozzle penetration in Filter Fines Depressurization Bin used to vent the hopper during depressurization cycles was relocated from the side of the bin to top. It was felt the fines were escaping during the depressurization cycles and causing Filter Fines Depressurization Filter to plug.

- New pressure sensing apparatus were fabricated for Filter Fines Removal Package to prevent instrument lines from plugging with fines.

- Several piping arrangements were changed to allow easier operation of equipment.

Start-up of the Gasifier began on December 17, 1998. The bed was lifted at 1200 hours and combustion began at 1630 hours. At 1800 hours, the Gasifier bed was slumped due to Filter Fine Depressurization Filter plugging with fines and stopping the Filter Fines Depressurization Bin from depressurizing. This was accompanied by a trip of the Fines Combustor on over-temperature. During the ensuing operational activities of re-firing the Fines Combustor and emptying The Filter Fines Removal Package, the Nitrogen Tank reached a low level and the start-up was aborted.

A call was placed to the vendor to expedite nitrogen trucks to site on 12/18/98. On 12/21/98, the Nitrogen Tank level was 62 inches, System Control was in a bind due to sub zero weather, and the start-up of the Gasifier was halted until after the holidays by the Plant Manager.

Integrated the Gasifier into the existing plant procedures. The Gasifier Lock Out Tag Out Procedure was made null and void.

On 12/22/98, a meeting with the Shift Supervisors was held in which the start-up of Gasifier was discussed.

The next start-up of the Gasifier was to be on 1/4/99.

2.3.3 GASIFIER MONTHLY REPORT FOR THE MONTH OF: January 1999

On 1/4/99, the Gasifier start-up began with the goal to go as far as possible without shutting down. The intent is to get the Gasifier stable, raise pressure, and begin removing LASH from the annulus area. The Syngas run lasted approximately three hours due to a shutdown caused by a blown expansion joint in the Fines Combustor.

A vendor representative arrived on-site 1/6/99 to inspect the joint and determine cause for failure. The following summarizes the findings:

- The joint had localized burning of fines in the mesh, which caused failure.
- The temperature indicator is a velocity type and the inlet was plugged with flyash.
- New, furnace type thermoprobes will be installed.
- An Inconel liner will be installed in the joint.

After shutdown, inspection of the baghouse revealed damage to the structure. There were 70 collapsed bags and some of the bracing had pulled loose. In addition, the Screw Feeder carrier bearing braces broke loose and the screw was flopping in the trough.

A time and material agreement with consultant was agreed to for coming out periodically and performing maintenance on the nitrogen plant. Consultants have thus far derimed the plant, restarted it, and repaired several leaks in the piping. They will make up a punch list and a spare parts list for future visits.

The following repairs/installations were performed during the period from 1/7/99 – 1/25/99:

- Furnace type thermocouples in Fines Combustor.

- Acoustical particulate sensing probes in the Syngas line.
- Baghouse repairs.
- Fines Combustor Inconel expansion joint liner.
- Combustion air line temperature indications in DCS.

The Plant Engineer is going to get the drawings for the Filter Fines Depressurization Filter and have a contractor fabricate another filter vessel for Filter Fines Depressurization Bin. Two of them will be put in parallel. The filters have been removed to allow the Filter Fines Removal Package to cycle efficiently. The Environmental Specialist was notified that we would be having some slight puffs of smoke coming out of the Flare periodically.

An attempt was made to install two new support gas spuds in the Fines Combustor. Vendor has been hesitant to let us put them in service. Mechanic is going to order a trip valve for the spuds, put them in, and get the vendor representative to come out and place the burners in service.

A second start-up attempt of the Gasifier began on 1/25/99. The goal is the same as the previous start-up. Delays in the start-up were causing by a blown rupture disc in Filter Fines Feed Bin, which was replaced, and difficulties in getting the Fines Combustor to operate smoothly. The controls for the Fines Combustor were tuned and after roughly 48 hours, at 1045 hours on 1/27/99, start-up began. The Environmental Specialist was notified that we would be having some slight puffs of smoke coming out of the Flare periodically, due to the removal of the filter elements from the Filter Fines Depressurization Filter. Start-up was hampered by the cycling of Filter Fines Removal Package, some losses of the Fines Combustor (which eventually caused high level indication in Hot Gas Filter), and slumping of the bed on two occasions.

The start-up was aborted due to a large emission of fines from the Flare stack at 0800 hours on 1/29/99. The Plant Engineer reported that the Syngas particulate probes have been pegged out for the last few hours, which, coupled with the fact that Filter Fines Feeder bound up several times during the run and Filter Fines Screw Cooler is bound and will not turn, indicates that failure of some candles in Hot Gas Filter has occurred.

Maintenance activities will begin on 2/1/99. The list of jobs includes opening up Hot Gas Filter for inspection, replacing rings in Recycle Gas Booster Compressor low pressure cylinder, repairing leaks in baghouse Screw Feeder trough, and inspecting the impeller for Recycle Gas Compressor for damage.

The new Filter Fines Depressurization Filter vessel is expected to be done on about 2/12/99. Once the installation is completed, we will be able to attempt another start-up.

2.3.4 GASIFIER MONTHLY REPORT FOR THE MONTH OF: February, 1999

The Gasifier was shut down for repairs during the month of February. During the last start-up attempt of 1/17/99, a failure occurred in Recycle Gas Booster Compressor. Upon dismantling the compressor, damage was found in the low and high pressure cylinders. The compressor was manufactured in Germany, which will cause difficulty in getting vendor support and parts here to repair the unit. Once a vendor representative came on site to inspect the damage, he reported that the use of the first stage for the instrument purges and Pressurization Gas Receiver was starving the second stage. This issue was turned over to KBR for their comment. The compressor is being used in the capacity it was designed for and a decision was made to repair the compressor and put it back into service as is.

During the lag time for the compressor repairs, in order to achieve the best results possible during the next start-up attempt, the following modifications to the Gasifier will be performed:

- Installation of a second Filter Fines Depressurization Filter vessel along with piping to provide back pulse capabilities for the filter.
- Inspect Fines Combustor for slagging.
- Install bin vibrators on Filter Fines Collection Bin, Filter Fines Depressurization Bin, LASH Collection Bin, and LASH Depressurization Bin.
- Install new flow transmitters in nitrogen to Gasifier steam rings.
- Repair leaks in baghouse and baghouse Screw Feeder.
- Unplug the fluffing nozzles in Filter Fines Collection Bin and Filter Fines Depressurization Bin.
- Unplug nozzles in Gasifier steam ring.

- Inspect the fines particulate probes and the outlet of Hot Gas Filter.

- Enlarge the size of Fines Collection Bin.

- Install manual vent line on Filter Fines Feed Bin.

- Install assist gas spuds and trip valve assembly in Fines Combustor.

Along with the above mentioned mechanical and Instrument changes, several operational activities will occur before we will be able to attempt another start-up of the Gasifier.

- Vacuum out the Filter Fines Feed Bin rupture disc line to the flare header.

- Empty the fines from Filter Fines Feed Package by burning in the Fines Combustor.

- Blow soot in HRSG during Fines Combustor operation.

- Empty the coal from Coal Feed Package to the LASH silo.

The above activities stemmed from a meeting that was held after the start-up in January. It was felt that the addition of the modifications would enhance the ability of the affected equipment to operate better under the conditions.

During a meeting held at the latter part of the month, the issue of bringing KBR into more of the operation of the plant was discussed. Several more meetings are planned during the month of March. During this meeting, it was suggested by the Plant Manager that we try to screen the coal to remove fines and use this for the fuel during the next Gasifier run. Also, different coal stocks could be put under consideration.

With the work required to complete and the time required to procure parts for the repairs and modifications, the next start-up of the Gasifier will not occur until the middle to late part of March.

2.3.5 GASIFIER MONTHLY REPORT FOR THE MONTH OF: March, 1999

The Gasifier was down for repairs for most of the month. Modifications and repairs were made to the unit. The list below states all work planned and the status as of the end of the planned period.

GASIFIER OUTAGE WORK LIST #2
1/22/99 – 3/24/99 UPDATED 3/24/99

WORK TO BE COMPLETED
Install New Filter Fines Depressurization Vessel.
Inspect Fines Combustor For Slagging.
Install Vibrators On Collection and Depressurization Bins.
Install New Flow Transmitters In Gasifier Steam Rings.
Repair Recycle Gas Booster Compressor.
Repair Leaks In baghouse Screw Feeder.
Unplug Fluffing Nozzles In Filter Fines Collection & Depressurization Bins.
Unplug Nozzles In Gasifier Steam Ring.
Inspect Particulate Probes.
Repair Pressure Problems With Heat Transfer Fluid Pump.
Increase Backpulse In Dust Collector.
Inspect Hot Gas Filter for broken candles.
Empty Coal Feed Package To LASH Silo.
Vacuum Out Filter Fines Feed Bin Rupture Disc Line To Flare Header.
Empty fines from Filter Fines Feed Package by burning in Fines Combustor.
Enlarge the size of Fines Collection Bin.
Install manual vent line on Filter Fines Feed Bin.
Blow soot in HRSG during Fines Combustor operation.
Screen coal to fill Silo.
Inspect Syngas Module inlet strainer.
De-inventory Gasifier.

On 3/29/99, start-up activities in the Gasifier began. Before the refueling of the unit could begin some ring nozzles had to be unplugged, the Gasifier had to be cleaned of old bed material, and some minor repairs had to be made. At approximately 1600 hours on 3/30/99, operations was given orders to begin with step #1 in the start-up procedure. The Gasifier was refueled, several operational problems were sorted out, and the bed was fluidized. The level was determined to be adequate and heat-up began. Shortly before midnight on 3/31/99, combustion in the Gasifier bed began. Start-up had begun and will continue into the next month.

2.3.6 GASIFIER MONTHLY REPORT FOR THE MONTH OF: April, 1999

The month began with the Gasifier in a start-up situation. The start-up was aborted due to seal leakage in LASH Feeder. This problem was repaired and start-up was continued. The Gasifier was ramped to a pressure of 200#, which was a new milestone for this project. The Gasifier run was halted when problems with the cycling of the Coal Feed Package created a Gasifier Type II Shutdown. The coal transport line plugged when Coal Depressurization Bin dumped into an empty Coal Feed Bin while Coal Feeder was running. We speculate that the coal ran through the screw feeder and overloaded the transport system. Three other problems were discovered at this time also. Fines Combustor fast-acting thermocouple burned out, Sulfator Cyclone Fines Feeder seal is leaking, and Filter Fines Depressurization Bin valve seal blew. Gasifier was tagged out for repairs. On the positive side, the annulus temperature appeared to be dropping while the Gasifier was at 200#.

Another start-up was attempted on 4/7/99. It was short-lived, however, due to the bridging of material in the Filter Fines Removal Package. The bins would not empty in a rapid manner. To complicate things, the fines carbon content went through a transition and we lost the Fines Combustor on high temperature. A rupture disc in the Filter Fines Feed Bin blew during this period. The Gasifier was once again depressurized and tagged out for repairs. Valve on Coal Feed Depressurization Bin also required seal replacement. The valve would not fully close.

On 4/9/99, Gasifier start-up was once again attempted. The coal transport line was plugged and all efforts to free it up were unsuccessful. The Gasifier was tagged out and the coal transport line dismantled and vacuumed out. It was completely full of coal and limestone. Gasifier was immediately back into start-up mode once the line was emptied and reassembled. At 160# pressure on the Gasifier, a Hi-Hi level in the Hot Gas Filter occurred and the bed was slumped. Operations also had difficulty in keeping the Fines Combustor operating during this period. While the Gasifier was down for this period, it was decided to remove the nozzles from the Filter Fines Collection and Depressurization Bins and replace them. Consultant was on site for this run and he made the necessary recommendations to I&C for wiring up the assist spud trip valves in the Fines Combustor.

Consultant for Nitrogen Plant was on site 4/15/99 – 4/18/99 to perform required maintenance and operation on the nitrogen plant. The plant required a total derime because of Carbon Dioxide infusion into the back portion. In addition, at this time, oil changes were done on Air compressor and Expander.

On Monday, 4/19/99, another start-up of the Gasifier was attempted. The coal transport line was plugged again and dismantling required. No material was found in the line, so it was assumed the pluggage was inside the Gasifier feed tube. The transport line was reassembled and the Gasifier was fired and brought to operating temperature in a attempt to free up what is inside the feed tube. This failed, so another idea for unplugging the feed tube was tried. A 16-gage shot gun was used to shoot up into the feed tube to break loose the obstruction. In addition, Coal Feed Package was emptied of all coal and limestone and readied for coke breeze addition. M. W. Kellogg Process Engineer indicated the bed level in the Gasifier was too low for another start-up and the carbon content was lacking.

The shotgun method for unplugging the feed tube in the Gasifier failed to clear the obstruction. The only option at this point was to empty the Gasifier and inspect the feed tube from inside. A Vacuum Truck was required on-site to do this. There was no ash flow through the feeder and grinder. Once the Gasifier was emptied to the point where we could examine the Air/Feed tube Assembly, it was found that the outer Air Tube was missing. Mechanics and operators went inside and broke loose what material they could from around the feed tube. Some samples of the material were taken and sent off for analysis. The Gasifier will be down for an extended period while the cause of this mishap is identified and repairs made.

A contractor has been cleared to come on-site to help us with some of the problems we are encountering with the waste removal equipment. They spent three days here observing and talking with people and will draft a report with recommended changes. Once the report is in hand, we will determine which recommendations make sense for us to do. Any modifications that can be done to any equipment during the extended Gasifier outage will be done to insure us the greatest chance for success the next time we try to start the Gasifier.

2.3.7 GASIFIER MONTHLY REPORT FOR THE MONTH OF: May, 1999

The Gasifier was down for repairs the entire month of May, 1999. During a start-up attempt at the end of April, we experienced damage in the annulus area to the combustion air tube. The bottom of the Gasifier was removed to allow access to the Air/Feed Tube Assembly for removal and inspection. A good portion of the combustion air tube was missing due to apparent melting. The coal feed tube was mostly intact except for the guide fins that center it inside the combustion air tube.

The following work list has been compiled to summarize the extent of activities that will be required before we can attempt the next Gasifier start-up:

GASIFIER OUTAGE WORK LIST #3

WORK TO BE COMPLETED
Remove And Replace Bottom Of Gasifier. Repair Feed Tube Assembly.
Install Clean Out Nozzles In Coal Transport Line.
Install Fines Diversion Line To Waste Silo.
Install Nitrogen Purges to Waste Silo.
Install New Designed Nozzles In Filter Fines Removal Package.
Construct And Install Debris Catcher In Bottom Of Gasifier.
Clean Out The Steam And Recycle Gas Rings And Nozzles.
Install Assist Burners, Including Trip Valves, In Fines Combustor.
Complete Installation Of Grit Removal Vessels Beneath HRSG.
Repair central vacuum line in Gasifier.
Modify Medium Level Probe In Filter Fines Feed Bin.
Install Hard Pipe Connection From Plant Air To Air Dryer.
Install Hard Pipe Connection From Recycle Gas To Gasifier Steam Rings.

It is estimated the scope of work will require approximately two months to complete at a cost of $500,000.00. In addition to the work list, outside contractors have been contacted to inspect spalling of refractory inside of the Gasifier and provide an estimate of repairs required. The refractory spalling is not major, but will require some patching.

Once a cause for the damage to the Air/Feed tube has been determined, the fitting of the assembly will be in order to accommodate a debris guard that will be designed for the annulus area. This guard will keep any pieces of ash or refractory larger than the throat area from getting into and plugging up the annulus. We have experienced much difficulty with this.

The installation of a Filter Fines Diversion Line will be completed before the next attempted Gasifier start-up to allow sending fines directly to the Waste Silo, bypassing the Fines Combustor. We are hoping that this will give us an opportunity to get longer run times in. The Fines Combustor has caused us grief in the past. Assist gas burners will be put into service in the Fines Combustor to aid the stability of the unit.

2.3.8 GASIFIER MONTHLY REPORT FOR THE MONTH OF: June, 1999

The Gasifier was down for repairs and modifications during the entire month of June. The following list of activities will sum up the total scope of work:

GASIFIER OUTAGE WORK LIST #3
4/29/99 – 7/08/99 UPDATED 6/30/99

WORK TO BE COMPLETED
Remove And Replace Bottom Of Gasifier. Repair Feed Tube Assembly.
Install Clean Out Nozzles In Coal Transport Line.
Install Newly Designed Nozzles In Filter Fines Removal Package.
Construct And Install Debris Catcher In Bottom Of Gasifier.
Clean Out The Steam And Recycle Gas Rings And Nozzles.
Install Assist Burners, Including Trip Valves, in Fines Combustor.
Repair central vacuum line in Gasifier.
Modify Medium Level Probe In Filter Fines Feed Hopper.
Install Hard Pipe Connection From Plant Air To Air Dryer.
Install Hard Pipe Connection From Recycle Gas To Gasifier Steam Rings.
Install bypass line around HRSG outlet with regulator valve.
Repair Gasifier refractory.
Reroute vent line from Filter Fines Depressurization Hopper.
Inspect Filter Fines Vent Filters for pluggage.
Modify Start Up Procedure to prevent rapid heat up of refractory.
Install walkway from 3rd level Gasifier to Fines Combustor.
Install Nitrogen Purges to Waste Silo.

The Gasifier coal feed tube was damaged during the last attempted start-up in the month of April. Analysis of the failed area by outside agencies determined the cause to be erosion. Upon further investigation, an orifice was left out of an instrument tap during the assembly of the Gasifier last year. The instrument purge flow is high pressure nitrogen (540 PSIG) from the first stage of the Recycle Gas Booster Compressor. This unrestricted flow, along with the solids in the area eroded a hole in the air tube. This in turn caused the release of air into the annulus area, combusted fuel that had congregated, and melted a portion of the air tube.

An Engineering Design firm was asked to provide a "catcher" for installation in the annulus area to prevent the possibility of large pieces of slag or refractory from getting into the cramped space and plugging it up. They declined to offer a design for the catcher, stating that less rapid heat up of the refractory would eliminate spalling and the need for the catcher. Several sections of the Gasifier refractory were taken out to the anchors and replaced with a different type of putty with stainless needles. The refractory vendor recommended this repair. The next anticipated start-up of the Gasifier will incorporate a new start-up procedure and method of initial heat-up and fueling.

Additional projects that were completed to help insure further success during the next start-up were:

- A Filter Fines diversion line. This will allow us to send Filter Fines from Filter Fines Removal Package to the Waste Silo during periods of upset.

- New “fluffing” nozzles were designed and installed in the Filter Fines Removal Package bins to prevent bridging of material. We have experienced much trouble with this in the past.

- Assist burners and associated trip mechanism have been installed in the Fines Combustor. We are hoping that this will improve the flame stability.

- A regulator was installed in the outlet of the Gasifier Steam Drum to throttle the steam output. Operations has had extreme difficulty controlling the drum level during low load operation.

The list indicates which projects have been completed. All uncompleted tasks are near the end. All activities will be completed by the middle of the week of July 5, 1999. The next anticipated start-up of the Gasifier was the week of July 12, 1999.

2.3.9 GASIFIER MONTHLY REPORT FOR THE MONTH OF: July, 1999

The first eleven days of the month of July were spent finishing Gasifier outage work that started in April. Considerable time and effort was spent in trying to ensure the best chances of success in the ensuing Syngas run scheduled for July 12, 1999.

GASIFIER OUTAGE WORK LIST #3
4/29/99 – 7/11/99 UPDATED 7/12/99

WORK TO BE COMPLETED
Remove And Replace Bottom Of Gasifier. Repair Feed Tube Assembly.
Install Clean Out Nozzles In Coal Transport Line.
Install Fines Diversion Line To Waste Silo.
Install Newly Designed Nozzles In Filter Fines Removal Package.
Construct And Install Debris Catcher In Bottom Of Gasifier.
Clean Out The Steam And Recycle Gas Rings And Nozzles.
Install Assist Burners, Including Trip Valves, In Fines Combustor.
Complete Installation Of Grit Vessels Beneath HRSG.
Repair central vacuum line in Gasifier.
Install Nitrogen Purges to Waste Silo.
Modify Medium Level Probe In Filter Fines Feed Bin.
Install Hard Pipe Connection From Plant Air To Air Dryer.
Install Hard Pipe Connection From Recycle Gas To R301 Steam Rings.
Install bypass line around Gasifier Steam Drum outlet with regulator valve.
Repair Gasifier refractory.
Reroute vent line from Filter Fines Depressurization Hopper.
Inspect Filter Fines Depressurization Filters for pluggage.
Modify Start Up Procedure to prevent rapid heat up of refractory.
Install walkway from 3rd level Gasifier to Fines Combustor.

Gasifier start-up efforts began on July 10, 1999 with a heat-up and curing process of the refractory repairs. The Gasifier was at 800°F and holding on Monday July 12, 1999. Several Gasifier leaks were found during the heat-up process and were repaired.

Factory service representative was on-site to commission new assist burners in the Fines Combustor. These burners are designed to enlarge the fireball in the incinerator and provide flame stability. It is also our hope that the fines will be more completely combusted.

Some more problems occurred that delayed start-up. The Booster Air Compressor tripped on high winding temperature. The problem was a loose wire and was corrected. The steam ring relief valves failed and had to be sent off for repair. The Recycle Gas Compressor surge protection did not operate properly. A plugged instrument line was the problem. The Desulferizer Cyclone Feeder had a leaking packing. It was tightened and then it sheared a drive pin. On the positive side, the new Filter Fines Diversion Line to the Waste Silo was tested and proved to work without any difficulty.

On 7/15/99, at 2015 hours, Syngas safety procedures went into effect. Coke Breeze was loaded and fired in the Gasifier. The temperature ramp with the new start-up method of putting a limestone bed in the Gasifier at the beginning, heating it up to 800°F for refractory heat soak, and then fueling with coke breeze proved to be very effective. Aside from some "usual" problems, start-up of the Gasifier was going smoothly.

After coal feed was started to the Gasifier, Filter Fines Removal Package experienced its usual problems with depressurization of Filter Fines Depressurization Bin and the bridging of material in Filter Fines Collection Bin. This subsequently caused a Gasifier Type II shutdown on Gasifier and operators went into slumped bed procedure. The combustion air line at the bottom of the Gasifier recorded some high readings and it was reported to be glowing red. An investigation concluded that a start-up air line block valve had been left open, which leaked a small amount of air into the line. The slumped bed material had enough fuel left in it to smolder.

After a short shutdown period, the combustion air line was checked for structural integrity by UT analysis and hardness testing. It proved to be unchanged by the heat excursion. In addition, by suggestion from a private consultant, it was determined that orifices placed at the inlet of the Filter Fines Depressurization Filters might help alleviate the depressurization problems that hindered the preceding start-up attempt. The filter elements are not holding up to the service that they are being subjected to.

The LASH Feeder at the bottom of the Gasifier bound up and would not turn. A piece of metal gasket material was found in it and by use of force, the feeder was freed up.

On July 22, 1999, another start-up attempt of the Gasifier was attempted. Problems were encountered with one of the valves (limit switch), Filter Fines Screw Cooler (bound up), Recycle Gs Compressor (tripped) and another leak at an instrument tap at the bottom of the Gasifier. Gasifier needed to be depressurized to repair the leak.

On July 23, 1999, Gasifier was fired again and Syngas production began. Approximately five (5) hours of coal feed occurred before the eventual shutdown of the Gasifier due to Filter Fines Removal Package failure to cycle and bridging in the bins. In addition, the Heat Transfer Fluid pumps failed and contributed to another high level in The Hot Gas Filter. The Type II shutdowns depleted the back up nitrogen reserves and all attempts to restart the Gasifier were aborted.

Meetings were held with the technical, mechanical, and operations personnel to get ideas of where to go from here. The following list has been compiled and will be implemented before we will try to start-up again. A back pulse line and valve need to be installed to clean the Filter Fines Depressurization Filters.

New filter material must be found to withstand the environment

PLC logic changes to incorporate the changes.

Install 1/16” orifice in Filter Fines Depressurization Bin fluffing line and leave on at all times. This is to stop bridging of material.

Raising the Filter Fines Depressurization Filters to a higher level in the Gasifier. A mechanic is going to check to make sure that we have the piping required on-site. We will not do this project at this time, but will be ready if need be.

Desulferizer Feed Cyclone Fine Feeder needs a work order to repack the shaft.

Go through the new copy of start-up procedure and point out mistakes. Make it user friendly.

See if we can do something about the Coal Feeder Gasifier Type II Trips. They caused us a lot of heartache last start-up.

2.3.10 GASIFIER MONTHLY REPORT FOR THE MONTH OF: August, 1999

The Gasifier was out of service for repairs and modifications during most of the month. The Filter Fines Removal Package proved to be the major obstacle towards getting the Gasifier to run for any extended period. We have arranged the services of outside engineering to help us with this situation. During a previous month, they came on-site and looked at the equipment extensively. They provided us with a site report and recommended modifications afterward. The changes that were made to the Filter Fines Removal Package during the month were a result of this report.

The first problem with the system was the Filter Fines Depressurization Filter elements were not holding up to the conditions. Several of the elements failed by either splitting or collapsing. We searched extensively for a vendor to supply us with a suitable sintered metal material that we could use to replace the existing filter elements. A vendor was able to supply stock, rolled tube that mechanics in our shop welded to fabricate the new filter elements. The filters were installed. Another recommendation was to supply back pulsing capabilities to the filter elements. Piping modifications, addition of fast-acting solenoid valves, and corresponding PLC logic changes were made to accommodate this. We took the 540 PSIG pressure supplied from Pressurization Gas receiver to supply the filter pulsing.

Plant Manager informed the Gasifier Team Leader that he will be going to the Gasifier User's Association Conference this year in San Francisco, October 17-20. He will be giving a presentation on the Pinon Pine IGCC Start-Up Experience

The Department Of Energy requires a decision matrix so that they will continue funding of the project. This has been completed and sent to Director.

Gasifier modifications were completed on 8/26/99. Testing of the new Filter Fines Removal Package back pulsing system and subsequent logic modifications began. Some steps in the

PLC had to be changed in order to get the sequence correct at a pressure of 75 PSIG in the Gasifier. With this accomplished, we began to raise pressure on the Gasifier. The intent was to go to 200 PSIG Gasifier pressure and test the system again. We ran into problems with the Recycle Gas Compressor at 160 PSIG and had to abort the test for the day. The compressor started to trip on surge protection.

On 8/27/99, testing of the Filter Fines Removal Package resumed. 200 PSIG on the Gasifier was reached, however, the Recycle Gas Compressor failed to run at this pressure once again. In addition to this, some additional changes to the logic were required to get the cycling of the bins to work at this higher pressure. The testing was aborted at the end of the day.

On 8/28/99, testing of the Filter Fines Removal Package was completed at 200 PSIG Gasifier pressure. We ran out of nitrogen in the liquid tank during the testing.

Gasifier start-up began again on 8/31/99. The Recycle Gas Compressor problem has been traced (hopefully) to trying to run it with too much differential pressure across the machine. Gasifier pressure was established at 75 PSIG and we ran a test on the Gasifier coal/air feed tube for Engineers. They suspect that there exists a hole in the air tube. This proved to be false during the testing. Gasifier start-up continued into the evening and will be detailed in the next month's report.

2.3.11 GASIFIER MONTHLY REPORT FOR THE MONTH OF: September, 1999

The Gasifier was lit off on the first day of the month. All went well until the bed was lifted and Syngas production began. To help us out, a representative from waste removal equipment manufacturer is on-site to watch the operation of their equipment. The Filter Fines Removal Package began failing again. The Filter Fines Depressurization Bin would not depressurize in a timely manner, despite the modifications that had been made to the system. The operation was aborted. The Plant Engineer was able to gather some very useful data from the run, however. In addition to the ever-occurring filter fines removal problems, the Recycle Gas Compressor started surging at about 160 PSIG Gasifier pressure. This will need to be looked into.

During the down time of the Gasifier, the Filter Fines Depressurization Filters were dismantled and inspected for damage. None was found. We made changes to the orifice sizes in the inlet and outlet. The depressurization orifice was changed from ¾” to 3/8” and the pressurization orifice was changed from 3/16” to ¼”. It is hoped that this will decrease the velocity during depressurization cycles and fewer fines will carry over to the filters. We restarted the Gasifier after the re-assembly of the apparatus and the Filter Fines Removal Package again caused eventual shutdown due to a high level in the Hot Gas Filter.

A meeting was held among different representatives from the crafts in the plant to discuss the recurring problem with the Filter Fines Removal Package. A conclusion was reached to use one of the Filter Fines Depressurization filters to take the initial brunt of the depressurization cycle and put the second filter in service to complete the cycle. In addition, a representative was called out to reprogram the Recycle Gas Compressor surge curve. On 9/8/99, we took the Gasifier all the way to 280 PSIG for test purposes and the Filter Fines Removal Package functioned well. Recycle Gas Booster Compressor problems were also resolved.

On 9/9/99, the Gasifier was lit off once again. The idea of letting one set of Filter Fines Depressurization Filters take the brunt of the depressurizing proved that the fines loading on the filters is tremendous. The filter "blanked off" almost immediately. As can be expected, the nuclear level detectors began failing and we had no level indication in the Filter Fines Depressurization Bin. Bridging of the fines in the Filter Fines Collection Bin also continued to haunt us. The start-up was eventually stopped. We reached a new level of performance on the unit. The Gasifier pressure was at 240 PSIG when the word to stop and depressurize was given.

During the evening of 9/10/99, the Pinon Control Room Operator reported that there was an emission of fines from the Flare when the Gasifier was almost depressurized. The rupture discs were a possible source of this, but proved to be intact. Upon opening up the Hot Gas Filter inspection doorway, broken candle filters were found laying in the bottom of the cone. Mechanics also disassembled the Filter Fines Depressurization Filters and the filters in it were imploded. After checking the data during the run, it became obvious that a slug of material became trapped in the Desulferizer Feed Cyclone and broke loose when conditions became right. This flooded the F501 with a mass of fines and bridging occurred in the bottom tiers. Pictures taken by Consultant proved this.

Another meeting was held to discuss the next plan of attack. The resizing of the Filter Fines Depressurization Filter is apparent. The Plant Engineer completed a design based upon data collected from recent Gasifier runs and confirmation with filter vendor. The modifications were put on hold until the Plant Manager gets the OK to proceed.

The Gasifier was officially into another outage at this point. An inspection of all vessels was performed and no anomalies were found. All vessels will be emptied of material, except the Gasifier. If we can remove some material from the bottom of the Gasifier to prove the functionality of the Grinder and Feeder, the bed will be left intact and the vessel will not be opened up for inspection.

Attended a meeting on 9/28/99 with representatives from SPPCo, Dynegy, TECO, KBR, and the DOE. The subject of the meeting was to gather ideas to help us out with this project. Some interesting things came out and will be pursued. These will be detailed in future monthly reports.

2.3.12 GASIFIER MONTHLY REPORT FOR THE MONTH OF: October, 1999

The Gasifier was out of service for repairs for the entire month of October, 1999. The following work list denotes the activities required and associated work orders for the unit to be ready for a subsequent start up:

Gasifier Outage Work List #4

WORK TO BE COMPLETED
Inspect Fines Combustor.
Inspect HRSG.
Inspect baghouse.
Inspect Sulfator.
Inspect Solids Cooler.
Inspect Hot Gas Filter.
Inspect Primary Gas Cooler.
Inspect Secondary Gas Cooler.
Replace Broken Candle Filters In Hot Gas Filter.
Clean Material Out Of Solids Cooler.
Clean Material Out Of Fines Combustor.
Perform Major PM On Nitrogen Plant Air Compressor.
Perform Overhaul On Nitrogen Plant Product Compressor.
Test LASH Removal From Gasifier.
Repair LASH Feeder.
Clean Up Black Cloud Incident.
Build and Install New Filter Fines Depressurization Filter Vessels.
Inspect Inlet Piping for Recycle Gas Compressor.
Unplug Grid Nozzles for Gasifier.
Heat Transfer Fluid Pump Leak And Piping Leak.
Close Up HRSG And Steam Drums.
Relief Valve Checks.
Bridging Problems?
Sulfator Air Compressor Lube Oil Level Alarm Is In.
Inspect Filter Fines Depressurization Filter Vent Line Check Valve.
Replace Safety on Gasifier Steam Ring.
Replace “Y” Strainer In Syngas Line.
Repair Hole In Sulfator Solids Transport Piping.
Press Oil In Booster Air Compressor Reservoir.

In addition to the above activity list, several other tasks have been completed to help insure a successful run during the next start-up. Filter Fines samples have been sent to the FETC and

KBR for analysis. Westinghouse and Micro-Filtrex have been contacted to design and identify the cost for a secondary filter for the Syngas line at the control module. This is to prevent fines ingestion by the combustion turbine in the event candles in the Hot Gas Filter break. KBR is putting the finishing touches on the design for the proposed Filter Fines Surge Bin. This device will allow mass removal of fines from the Hot Gas Filter and help stabilize the operation of the Fines Combustor. This project will go out for bid if it is needed.

The Gasifier Team Leader attended a Gasifier Users' Association Conference in San Francisco October 27-30, 1999. He gave a presentation on the Pinon Start-Up Experience

The Gasifier has quite a few nozzles that are plugged. Operations has used 120 PSIG service air to try and blow them free individually. The only recourse now is to completely de-inventory the bed from the Gasifier so that the nozzles can be dismantled and drilled out. New pulleys for the LASH Grinder have been ordered and once they are installed, this will increase the grinding power of the apparatus. Thus far, some of the bed material has been removed. It appears that it consists of refractory for awhile and regular bed material once the refractory had been ground up. The material has been issued to our lab for analysis.

The major project that will determine the date of the next Gasifier start-up is the construction of the new F503 vessels and the logic required. The canisters are being manufactured in Concorde, CA. Once they arrive on-site, a local contractor will begin the assembly. All other work on the Outage List should be completed by the time this project is done. It is estimated that it will be towards the end of the month before we can try another run on the unit.

2.3.13 GASIFIER MONTHLY REPORT FOR THE MONTH OF: November, 1999

The Gasifier was out of service for repairs and modifications during the entire month. It is being readied for another start-up attempt sometime during the middle of December, 1999. The goal for the next start-up will be to operate the unit at maximum throughput for an extended period. This will allow the removal of LASH from the annulus and the identification of possible problems in that area. The following work list details the work needed and the progress to date:

Gasifier Outage Work List #4
September 10, 1999 - ?

WORK TO BE COMPLETED
Inspect Fines Combustor.
Inspect HRSG.
Inspect Sulfator.
Inspect Solids Cooler.
Inspect Hot Gas Filter.
Inspect E401 Primary Gas Cooler.
Inspect E403 Secondary Gas Cooler.
Replace Broken Candle Filters Hot Gas Filter.
Clean Material Out Of Solids Cooler.
Clean Material Out Of Fines Combustor
Perform Major PM On Nitrogen Plant Air Compressor.
Overhaul On CP-53 Nitrogen Plant Product Compressor.
Test LASH Removal From R301 Gasifier.
Repair FD302 LASH Feeder.
Clean Up Black Cloud Incident.
Build and Install New F503 Vessels
Inspect Inlet Piping Recycle Gas Compressor.
Unplug Grid Nozzles Gasifier.
Heat Transfer Fluid Pump Leak And Piping Leak.
Close Up HRSG And Steam Drums.
Relief Valve Checks.
Bridging Problems- Skimmer Valves.
Lube Oil Level Alarm.

In addition to the above activities, a detailed work plan, with accompanying schedule, has been written for the DOE as a prerequisite to additional funding of the project through the Year 2000. Accompanying costs, both O&M and Capital have been assigned to the schedule. Previously, a workshop was held at the Tracy site to explore ideas regarding the Gasification unit. Attendees at the workshop included representatives from the DOE, TECO, DYNEGY, and SPPCo.

The Gasifier bed material has "set up" due to moisture and heat and is proving difficult to remove. The Gasifier has to be emptied because the grid nozzles are all plugged and the only way to free them up is to get inside. In the lower bed levels, what appears to be ash agglomeration has occurred. Personnel are using electric an jack hammer and buckets to remove the material. A sample of the ash will be sent to KBR Houston for analysis.

The Filter Fines Removal Lock Hoppers have a major modification ongoing. The Depressurization Filter has proven to be mis-designed by a factor of ten (10). Additional filter vessels are being installed and the accompanying valves and PLC logic. This project will be the determining factor for the date of the next start-up of the unit. The upper vessel in the package, has experienced several material bridging problems in the past. We have located a valve that is specifically designed to remedy this. The valves are manufactured in New Zealand. They will be installed prior to the next run of the Gasifier as well.

A proposal for bid to supply Full Time Equivalent (FTE) Engineering services to the project has been drafted and a list of possible contacts compiled. This is another of the prerequisites required to insure DOE funding of the project.

The Hot Gas Filter experienced breakage of quite a few (170 total) candles during the run in September. It was decided to "blank" off the empty candle sites until future runs. With the annulus area of the Gasifier still unproven, trying to run the Gasifier is the priority. Candles will be replaced in the future as the situation warrants.

Preliminary work on obtaining price quotations for a Secondary Syngas Filter to possibly be installed in the Syngas line between F501 and the Syngas Module are underway. PALL Filters and Siemens Westinghouse will be competing for this. Filters will also be procured and installed in the recycle gas line to protect the Recycle Gas and Recycle Gas Booster Compressors.

Finally, the design package for the Filter Fines Surge Bin has been completed by KBR. We have reviewed it and it is being prepared for bids.

2.3.14 GASIFIER MONTHLY REPORT FOR THE MONTH OF: December, 1999

The Gasifier was out of service for system modifications during the entire month. Installation of eight (8) separate Filter Fines Depressurization Filter vessels continued along with a new type of valve known as a "Skimmer" in the Filter Fines Collection and Depressurization Bins. The increased F-503 surface area is anticipated to alleviate the depressurization problems we have encountered in the past with the PG-503 Filter Fines Removal System. The Skimmer Valves are a special solids mixing valve that we found on the Internet. A company in New Zealand manufactures them. It took considerable effort to get them on-site. These valves are plug proof and will fluidize solids that have become deaerated.

The following work list will summarize the progress to this point with planned work:

Gasifier Outage Work List #4
September 10, 1999 - ?

WORK TO BE COMPLETED
Inspect Fines Combustor.
Inspect HRSG.
Inspect baghouse.
Inspect Sulfator.
Inspect Solids Cooler.
Inspect Hot Gas Filter.
Inspect Primary Gas Cooler.
Inspect Secondary Gas Cooler.
Replace Broken Candle Filters Hot Gas Filter.
Clean Material Out Of Solids Cooler.
Clean Material Out Of Fines Combustor.
Perform PM On Nitrogen Plant Air Compressor.
Perform Overhaul On Nitrogen Plant Product Compressor.
Test LASH Removal From Gasifier.
Repair LASH Feeder.
Clean Up Black Cloud Incident.
Build and Install New Vessels.
Inspect Inlet Piping Recycle Gas Compressor.
Unplug Grid Nozzles (Gasifier).
HTF Pump Leak And Piping Leak.

Close Up HRSG And Steam Drums.
Relief Valve Checks.
Bridging Problems- Skimmer Valves.
Lube Oil Level Alarm.
Inspect Vent Line Check Valve.
Replace Safety.
Repair Hole In Transport Piping.
De-Inventory Gasifier.
Install Debris Guard In Gasifier.
Five Cars Stoker Coal For Next Start Up.
Install Differential Pressure Taps. Incorporate Into DCS.
Start-Up: Order Nitrogen Trucks

A three week delay in proposed start-up has been initiated. The new proposed date for start up of the Gasifier will be January 24, 2000.

In addition to the scheduled work, progress has been made in the cost estimate for a secondary Syngas filter to be installed in the Syngas line between the Hot Gas Filter and the Gas Turbine. A proposal from manufacturer is being procured so that we will have a plan of attack once a decision is made in the future to try to burn the Syngas in the turbine. Along with this project, a means of filtering the inlets of Recycle Gas and Recycle Gas Booster Compressors is being explored.

The Gasifier proved to be extremely difficult to de-inventory during this outage. Refractory pieces conglomerated in the boot area and plugged the inlet to the grinder. We enlisted the services of a dynamite contractor to come out and set off small charges to break up the refractory pieces so we could get them out. The dynamiting on the vessel proved to be successful with no damage.

Enlisted the services of nitrogen consultant to come out and perform a complete derime on the nitrogen plant and subsequently start it up. Operations was notified of this and Shift Supervisors were told to allow operators who needed training on the facility to participate. By 12/6/99, the plant was up and running smoothly. Load was put on the facility for fine tuning and it has been running smoothly ever since.

A representative of the DOE spent a couple of days on-site reviewing data from the previous start-ups. He was asked to review this operation and see if his past experience at Waltz Mill could be of use. He has some concerns, along with the rest of us, as to whether or not the annulus area of the Gasifier will perform as designed. He helped develop a test procedure for withdrawing limestone. A procedure has been written. The test will be performed prior to the firing of the Gasifier later this month.

An Engineering Consultant spent a week on-site helping us with several of the ongoing projects. A debris guard was installed in the bottom annulus area of the Gasifier to prevent refractory pieces from agglomerating in the boot area and plugging up the works. The design of the Filter Fines Depressurization Filter, state of refractory in the Gasifier vessel, and proposed bid package for the new Filter Fines Surge Bin were reviewed by him. He has made comments on each for our benefit.

Finally, the past Plant Manager of the Waltz Mill Project has been enlisted as an operations consultant for the project. It was determined that his expertise would be of great benefit to us.

2.3.15 GASIFIER MONTHLY REPORT FOR THE MONTH OF: January, 2000

The Gasifier was out of service for repairs and modifications until Monday, January 24, 2000. The list below details all work that was done and completed in the time frame specified:

Gasifier Outage Work List #4
September 10, 1999 – January 21, 2000

WORK TO BE COMPLETED
Inspect Fines Combustor.
Inspect HRSG.
Inspect baghouse.
Inspect Sulfator.
Inspect Solids Cooler.
Inspect Hot Gas Filter.
Inspect Primary Gas Cooler.
Inspect Secondary Gas Cooler.
Replace Broken Candle Filters In Hot Gas Filter.
Clean Material Out Of Sulfator Solids Cooler.
Clean Material Out Of Fines Combustor.
Perform PM On Nitrogen Plant Air Compressor.
Perform Overhaul On Nitrogen Plant Product Compressor.
Test LASH Removal From Gasifier.
Repair LASH Feeder.
Clean Up Black Cloud Incident.
Build and Install New Vessels.
Inspect Inlet Piping Recycle Gas Compressor.
Unplug Grid Nozzles (Gasifier).
HTF Pump Leak And Piping Leak.
Close Up HRSG And Steam Drums.
Relief Valve Checks.
Bridging Problems- Skimmer Valves.
Lube Oil Level Alarm.
Inspect Vent Line Check Valve.
Replace Safety.
Repair Hole In Transport Piping.
Install Debris Guard In Gasifier.
Five Cars Stoker Coal For Next Start Up.
Install Differential Pressure Taps. Incorporate Into DCS.
Start-Up: Order Nitrogen Trucks.

On 1/24/2000, efforts began to test the modifications installed. Some faulty welds were found during full pressure testing and they were repaired. Subsequent pressure testing proved the modifications to be sound. The Gasifier was brought up to full load pressure (280 PSIG) and the Filter Fines Removal Package logic was tested. The cycling of the package was as expected. Data gathered showed that it took approximately 12 minutes for the Filter Fines Removal Package to complete one full cycle at this pressure. This was deemed as acceptable.

The full-fledged start-up efforts by operations began on Thursday, 1/28/2000. We filled the annulus area of the Gasifier with limestone and operators were allowed to play with the ring flows and watch trends. This is a new experience for the operations staff, so time will be given for them to get a feel of it. A private consultant, who was hired to help with the operation of the unit, suggested the addition of trends to the DCS screens as an aid to operators.

The addition of limestone to the unit continued until a total of 70 tons was inventoried. This bed of limestone was then heated up to approximately 700°F and we attempted to withdraw it from the bottom through the LASH Grinder and Feeder. Subsequent failure of the feeder seals caused us to shut the unit down for repairs. The feeder vendor was contacted and some recommendations were given to us to prevent future failure of this feeder. It has plagued us in the past. These suggestions will be implemented.

A number of problems occurred during this start-up attempt of the Gasifier. A partial list is below:

- Lash Removal Package had a bad pressure transmitter that needed to be replaced.
- LASH Grinder inboard seal lost flow indication.
- Filter Fines transport line plugged.
- Feeder transport gas flow transmitter plugged.

- The limestone in the storage silo was coming out in clumps on the feeder belt.
- Transport gas for LASH Feeder had logic problems.
- Coal Feed Pressurization Bin vent valve seal.
- Recycle Gas Compressor had, and still has, discharge pressure control problems.
- LASH Feeder transport line plugged.
- LASH Feeder seal failure.
- Nitrogen usage is overtaxing the abilities of the plant.

On the positive side, it was proven that the LASH Feeder seals and transport gas flow did not have any adverse affect on the cooling effect of the Gasifier annulus. This was an ascertion by the process engineers of KBR. Not enough material withdrawal occurred to prove the annulus operation conclusively, so repairs to LASH Feeder will be made and a hot limestone withdrawal test will be performed again.

2.3.16 GASIFIER MONTHLY REPORT FOR THE MONTH OF: February, 2000

The month began with the Gasifier down for repairs. We were attempting to run a hot limestone withdrawal test when the LASH Feeder seals blew. Repairs are underway.

Gasification Engineering, whom we have contracted for engineering service for the project, came on-site and we held a kick-off meeting on 2/2 & 2/3/2000. We discussed the goals of the project and the major encumbrances that we have. A task list was generated from the meeting and is as follows with associated capital account project numbers:

1. Gasifier Annulus/LASH Removal 20664
2. Gasifier Refractory 20665
3. Sulfator Design Review 20667
4. Gas Turbine Secondary Filter 20668
5. Material Handling 20669
6. Hot Gas Filter Problems 18353
7. Filter Fines Surge Bin 19691

On 2/4/2000, we attempted a second hot limestone withdrawal test on the Gasifier. It proved inconclusive as the grinder and feeder tripped on high inlet temperature on several occasions. We have some ability to cool the LASH material, but it appears not enough to sustain continuous operation of the LASH Feeder and Grinder.

On 2/5/2000, the first Gasifier Syngas run was attempted. A delay occurred when the rupture discs in the Coal Feed Surge Bin were blown out and had to be replaced. The cause for this was determined to be a glitch in the PLC that controls the package. The unit was restarted and eventual stopping of the start occurred when the Filter Fines Depressurization Bin valve limit switch incurred problems and delayed operation of the Filter Fines Removal Package. A Hi-Hi Level in the Hot Gas Filter eventually caused a unit trip. This was repaired by gluing two pennies onto the limit. Some LASH was removed during the run, but not continuously as before.

On 2/7/2000, the second Gasifier Syngas run was attempted. We were able to get the unit to 200 PSIG pressure and stable conditions. This run eventually ended when the vent valve for the Coal Feed Pressurization Bin failed and we were unable to get fuel into the unit. In addition, the nitrogen backup tank emptied and we lost suction in the backup pump. The valve was repaired.

On 2/11/2000, the third Gasifier Syngas run was attempted. The unit was brought to 240 PSIG and stable conditions. Eventual failure occurred when a Hi-Hi Level in the Hot Gas Filter tripped the Gasifier. The Gasifier annulus became plugged during this run and any attempts to remove material from the bottom failed.

On 2/12/2000, the fourth Gasifier Syngas run started. We didn't get very far with this one as we were plagued from the onset by compressor problems. The Recycle Gas Booster Compressor would not stay running for any period. The suction pressure would drop and trip the unit. This is needed for the Filter Fines System, so we eventually achieved a Hi-Hi Level in the Hot Gas Filter again and futility struck. The Air Feed Tube for the Gasifier also appeared to have become obstructed by something. Attempts to blow it out caused a small, one time Flare emission. We looked in the Hot Gas Filter vessel with a borescope and found no damage.

On 2/14/2000, the fifth Syngas run on the Gasifier started. This was aborted later because of three things: low nitrogen tank level, Recycle Gas Compressor failed to keep pressure, and inability to remove LASH material from annulus. A decision was made to wait until the nitrogen tank could be filled before we try it again.

On 2/25/200, the sixth and final Gasifier Syngas run took effect. This start-up went well except for a HTF leak at the Filter Fines Screw Cooler. The Gasifier was taken to several loads and held there for a period to determine the fines production rate at that specific load. The run lasted until 2/26/2000 and eventually ended on Hi-Hi level in the Hot Gas Filter. It was very encouraging to note that the Filter Fines Removal Package kept up with the production of fines. The level in the Hot Gas Filter increased due to two nuisance trips of the unit and apparently the Filter Fines Screw Cooler needs to run faster than it does.

Any future attempts to run the Gasifier have been aborted because of two major problems. The Coal Feed Tube is plugged and all efforts to clear it have failed. The LASH material will not flow through the feed and grinder. The Gasifier will be cooled and de-inventoried for future work.

2.3.17 GASIFIER MONTHLY REPORT FOR THE MONTH OF: March, 2000

The Gasifier was out of service for the entire month of April, 2000, for repairs, modifications, and maintenance. While attempting to de-inventory the contents of the Gasifier to ready it for removal of the annulus section and refractory inspection, we found that it could not be accomplished through the bottom with the LASH removal equipment. A vendor had to be called out to use their vacuum truck to empty the vessel.

Gasification Engineers were on site 3/7/2000 to discuss what the future progress of the project would entail. During the meeting, an action item list was put forth that they will begin acting upon. The next intended goal for the Gasifier is to run for 60 hours uninterrupted. The following list of items will be proposed for completion before the next attempted start-up of the unit:

A. Annulus refractory redesign to provide internal area.

B. Increase the size of the opening of the LASH outlet valve.

C. Finer control for recycle gas rings.

D. Gasifier nozzle and gas distribution.

E. Gasifier heat up procedure.

F. Gasifier refractory – repair spalled areas.

G. Recycle Gas Booster Compressor suction supply from nitrogen – increase pipe size.

H. Solutions to the Hot Gas Filter level problems.

I. Hot Gas Filter – emergency high level dump.

J. Thermowells in the annulus area.

K. Recycle gas cooler for recycle gas rings on Gasifier.

Based upon the list, a schedule for the work along with justification for the projects was completed. A cost for the work has been estimated and sent to upper management of the company for approval.

Once the Gasifier bed material was removed from the vessel, the large manway door was opened, the grinder and feeder removed, and all associated electrical and instruments were taken off to ready the annulus for removal. When the annulus section was finally on the ground, several things were found. The debris guard that we installed to block refractory from getting into the throat of the annulus had been ripped off from it's original position and wedged itself down lower in the throat. The end of the air tube had all of the refractory removed from it. The air tube also had a hole burned in it at the base. This hole was sealed with slag and did not cause any other damage. The Gasifier annulus section will be shipped off to refractory repair vendor once approval for the work is received.

The Gasifier refractory was found to be in bad shape by the Gasification Engineering representative. The entire cone section and 18 feet' up the walls needs to be demolished and replaced. The engineer has been working with a selected refractory vendor to do the work. Cost quotes have been received and approval for the work is pending. The refractory seems to be in very good shape above the bed level in the Gasifier.

The Hot Gas Filter was opened up for inspection and no anomalies were found. No broken candles exist and the vessel was clean. The Gasification Engineering representative inspected the vessel and will get back later with recommendations, if any.

Inspection of all other vessels in the Gasifier Island was completed. The Recycle Gas Cooler and Recycle Gas Trim Cooler show no signs of wear or corrosion. The Fines Combustor is clean. The Desulfurizer Feed Cyclone is plugged up with material and mechanics worked on it. More will be required later.

The nitrogen plant has been shut down and pickled for long storage.

Scaffolding has been erected in the Gasifier to facilitate the pending refractory work. Most of the Gasifier nozzles were plugged upon inspection. Mechanics will remove the spool pieces from each nozzle and clean them out. The nozzle inserts will be prepared for shipping. Gasification Engineering will recommend a vendor to send them to for modification. The ceramic nozzles in the Gasifier grid have broken apart. The new nozzle modifications are expected to prevent this.

At the request of the Pinon Plant Manager, future capital expenditures on the Gasifier will go through the following steps:

1. An idea will be brought forth to solve a problem.
2. Gasification engineers will help in determining if the idea is valid.
3. The valid idea will be mapped out as to cost and time.
4. Plant Manager will have to approve the idea.
5. It will then go to the Director and Vice President.
6. Finally, the DOE will be notified.

This process is necessary in order to insure that SPPCo. satisfies the terms of the current DOE agreement.

2.3.18 GASIFIER MONTHLY REPORT FOR THE MONTH OF: April, 2000

The Gasifier was down for modifications and repairs the entire month of May, 2000. Data collected from runs previously held during the month of February indicated problems with design that needed to be addressed. Gasification Engineering Corporation has been given a master task list to address. With their assistance, flaws in the operation of the Gasifier will be re-engineered and modifications made. An Outage Work List has been generated and the progress to date noted on the following:

Gasifier Outage Work List #5
3/1/2000 – 7/31/2000

WORK TO BE COMPLETED
De-inventory Gasifier
De-inventory Sulfator
Redesign Gasifier nozzles
Unplug Gasifier Coal Feed Tube
Remove Annulus from Gasifier
Gouge out cast refractory and replace with brick
Install Gasifier annulus
LASH Depressurization Filter design and repairs
Hot Gas Filter high level dump installation and design
Install escape ladder at Sulfator Solids Screw Cooler
Open and inspect Product Gas Cooler
Open and inspect Product Gas Trim Cooler
Open and inspect Hot Gas Filter
Open and inspect Gasifier
Open and inspect Fines Combustor
Open and inspect HRSG
Open and inspect baghouse
Rebuild Desulfurizer Feed Cyclone Fines Feeder and unplug transport line
Repair spalled refractory in Gasifier
Install suction filter for Recycle and Recycle Gas Booster Compressors
Change gear sizes on Filter Fines Screw Cooler to run faster
Increase Recycle Gas Booster Compressor suction supply
Repair valve in LASH Removal Package
De-inventory Coal Feed Package
Install nitrogen blast nozzle at base of feed tube
Remove the mechanical stop from Syngas Temperature Control Valve
Change valve trim in recycle gas ring control valves
Repair hole in LASH Feeder transport line

Calibrate PDT's at Flare
Remove and inspect Syngas Module inlet strainer
Place blind in start up air line to Desulfurizer Feed Cyclone
Open/close manway at top of Gasifier
Repair hole in Gasifier air/feed tube assembly
Replace refractory on Gasifier air/feed tube assembly

After submitting a detailed schedule and associated cash flow to SPPCo management, approval was received to begin writing purchase orders. Thus far, the Gasifier annulus has been loaded on a truck and sent to vendor for required work. A contractor has been contracted to replaced the spalled refractory in the Gasifier. That work will begin later in May. Damage to the Gasifier air and coal feed tubes will be repaired by another contractor.

Training for new operators was given during the month. They will take their tests while on shift.

Weekly updates, via conference calls, will be made with Gasification Engineering. We will track the progress of the tasks by correspondence.

All plugged lines, vessels, and other operational anomalies have been rectified.

2.3.19 GASIFIER MONTHLY REPORT FOR THE MONTH OF: May, 2000

The Gasifier was out of service for the entire month of May, 2000, for major modifications. The attached Outage Work List conveys the progress to date of the projects and work planned:

Gasifier Outage Work List #5
3/1/2000 – 7/31/2000
Updated 5/30/2000

WORK TO BE COMPLETED
De-inventory Gasifier
De-inventory Sulfator
Redesign Gasifier nozzles
Unplug Gasifier Coal Feed Tube
Remove Annulus from Gasifier
Gouge out cast refractory and replace with brick
Install Gasifier annulus
LASH Depressurization Filter design and repairs
Hot Gas Filter high level dump installation and design
Install escape ladder at Sulfator Solids Screw Cooler
Open and inspect Product Gas Cooler
Open and inspect Product Gas Trim Cooler
Open and inspect Hot Gas Filter
Open and inspect Gasifier
Open and inspect Fines Combustor
Open and inspect HRSG
Open and inspect baghouse
Rebuild Desulfurizer Feed Cyclone Fines Feeder and unplug transport
Repair spalled refractory in Gasifier
Install suction filter for Recycle and Recycle Gas Booster Compressors
Change gear sizes on Filter Fines Screw Cooler to run faster
Increase Recycle Gas Booster Compressor suction supply
Repair valve in LASH Removal Package
De-inventory Coal Feed Package
Install nitrogen blast nozzle at base of feed tube
Remove the mechanical stop from Syngas Temperature Control Valve
Change valve trim in recycle gas ring control valves
Repair hole in LASH Feeder transport line
Calibrate PDT's at Flare
Remove and inspect Syngas Module inlet strainer
Place blind in start up air line to Desulfurizer Feed Cyclone
Open/close manway at top of Gasifier

Repair hole in Gasifier air/feed tube assembly
Replace refractory on Gasifier air/feed tube assembly

The status of the ongoing projects is as follows:

Redesign Gasifier Nozzles – Precision Industries has the nozzles and is modifying them. New tips are being put on the nozzles to replace the current ceramic ones that failed to hold up.

The Gasifier annulus section is currently at contractor's shop where the existing refractory in the vessel has been gouged out, new anchors welded in place, and refractory and brick replaced. It is estimated to be back on-site around the middle of June.

LASH Depressurization Filter Design And Repairs – Gasification Engineering is still working on the design for this.

Hot Gas Filter Emergency Dump – Gasification Engineering is still working on the design for this.

Repair Spalled Refractory In Gasifier – Contractor is on-site and has begun the demolition process of the refractory in the cone section of the Gasifier and 18 feet up the walls. It will eventually be replaced with Greencast, one layer. Estimated completion is the end of June.

Install Recycle and Recycle Gas Booster Compressor Suction Filter – Gasification Engineering has this in design phase.

Increase Recycle gas Booster Compressor Suction Supply – It has been determined that the pipe sizing to the compressor from the 400# Nitrogen header is correct. The regulators that supply the compressor will be readjusted to a higher setpoint.

Repair Valve In LASH Removal Package – Mechanics have the valve disassembled and will reassemble it as soon as possible.
Install Nitrogen Blast Nozzle At Base Of Feed Tube – This is to allow a means of unplugging the Coal Feed Tube while the

Gasifier is full of material. An estimate for the work will be acquired and the work completed before the next start-up of the unit.

Adjust The Mechanical Stops On the Product Gas Temperature Control Valves – The current setup of these valves is based on total flow of Syngas through the coolers. We need to change this in order to be able to put the Gasifier through a slower heat-up period. The inlet to the Hot Gas Filter cannot be allowed to exceed 400°F or danger of ignition in the filter arises.

Smaller Valve Trim For Recycle Gs Control Valves – These valves control the flow of recycled gas into the Gasifier rings located in the annulus. The valve trim has proved to be too large for low load applications. The trim has been ordered and will be installed.

The Syngas Module inlet strainer has been removed and there is a light coating of fines in the strainer and the piping. It is obvious that the Hot Gas Filter is leaking by somewhat. Gasification Engineering is working on a maintenance recommendation for the filter.

The Gasifier Coal/Air Tube Assembly is in a shop in Concorde, CA. The repairs to the tube have been made and the refractory will be replaced on the tube next week. It should arrive on-site by the middle of the month.

Rebuild LASH Feeder – The feeder is torn apart. Once a representative from Gasification Engineering has a chance to inspect the parts, he will make recommendations and the feeder will be reassembled.

Install Gas Purge At Base Of Flare – A study is being conducted to design and install a purge for the Flare from the natural gas line. This is intended to take the place of the High Rate Nitrogen purge that has caused us to run out of Nitrogen in the past. We have an estimate for installation and are waiting for Global to do a Haz-Op on it.

With the Gasifier refractory job due for completion by the end of June, re-assembly of the annulus section and the nozzles will follow. The remaining projects that are Gasification Engineering's responsibility are currently being addressed and will be implemented ASAP.

2.3.20 GASIFIER MONTHLY REPORT FOR THE MONTH OF: June, 2000

The Gasifier was out of service for repairs and modifications during the entire month of June, 2000. Progress was made to complete the items on the outage work list below:

GASIFIER OUTAGE WORK LIST #5
3/1/2000 – 7/31/2000
Updated 7/5/2000

WORK TO BE COMPLETED
De-inventory Gasifier
De-inventory Sulfator
Redesign Gasifier nozzles
Unplug Gasifier Coal Feed Tube
Remove Annulus from Gasifier
Gouge out cast refractory and replace with brick
Install Gasifier annulus
LASH Depressurization Filter design and repairs
Hot Gas Filter high level dump installation and design
Install escape ladder at Sulfator Solids Screw Cooler
Open and inspect Product Gas Cooler
Open and inspect Product Gas Trim Cooler
Open and inspect Hot Gas Filter
Open and inspect Gasifier
Open and inspect Fines Combustor
Open and inspect HRSG
Open and inspect baghouse
Rebuild Desulfurizer Feed Cyclone Fines Feeder and unplug transport
Repair spalled refractory in Gasifier
Install suction filter for Recycle and Recycle Gas Booster Compressors
Change gear sizes on Filter Fines Screw Cooler to run faster
Repair valve in LASH Removal Package
De-inventory Coal Feed Package
Remove the mechanical stop from Syngas Temperature Control Valve
Change valve trim in recycle gas ring control valves
Repair hole in LASH Feeder transport line
Calibrate PDT's at Flare
Remove and inspect Syngas Module inlet strainer
Place blind in start-up air line to Desulfurizer Feed Cyclone
Open/close manway at top of Gasifier
Repair hole in Gasifier air/feed tube assembly
Replace refractory on Gasifier air/feed tube assembly

As of the end of the month, the Gasifier refractory in the cone section and 18 feet up the walls was demolished and replaced with one layer of Greencast Refractory 12 inches thick. This was done to prevent spalling and plugging up of the LASH outlet at the bottom of the annulus. Contractor demolished the refractory inside of the annulus and replaced it with firebrick in the grid area and cast refractory in the boot. Another contractor repaired the hole that was burned in the Gasifier air feed tube and the refractory on it was replaced. These modifications were done in order to gain better success at LASH removal during the next start-up of the Gasifier.

According to estimations made by Gasification Engineers, the added area inside of the annulus will provide sufficient residence time for the cooling of the LASH. Up until now, we have been unable to accomplish this. The one layer of refractory inside the Gasifier will limit spalling of large pieces that have, in the past, prevented us from moving LASH out of the bottom of the unit. Future burning inside of the Gasifier air feed tube will be addressed by procedure.

Gasification Engineers have some projects that will not be completed by the August 1, 2000 target date for start-up. The secondary suction filter for the Recycle and Recycle Gas Booster Compressors has been delayed by the inefficiency of the current set up in the Hot Gas Filter. The operation of the Hot Gas Filter will take precedence over the installation of a barrier filter. It was felt that the barrier filter would just blind off in short periods due to the current operation. Filter elements and new failsafe devices have been sent to the Wabash facility for testing in their slip stream unit. Their expertise in this particular field is going to be a big help in getting us through the final hump of being able to do a fuel swap in the future.

We also asked the Gasification Engineering people to design an "Emergency Dump" line from the Hot Gas Filter to the Gasifier so that we could get rid of filter fines during transient situations. The design and procurement of necessary parts will not be completed until the October outage. This system will act as a back up to the current Filter Fines Removal Package.

The Gasifier nozzle inserts are at a vendor of Gasification Engineering being modified and are due on-site July 11, 2000 for installation. A new vent system design for the LASH removal hoppers has been sent to us and parts are on order. Modifications at the Flare to better control the purges from the nitrogen drum are in progress. Finally, the thermocouples that fit into the wells in the annulus will be looked at to see if changes are required due to the change in thickness of the internal refractory.

Projected start-up of the Gasifier remains August 1, 2000 barring any unforeseen circumstances.

2.3.21 GASIFIER MONTHLY REPORT FOR THE MONTH OF: July, 2000

The Gasifier was out of service for the entire month of July, 2000 for engineering modifications. As indicated by the list below, the work completed during the whole outage has been quite immense. With the help of Gasification Engineering we were able to complete all items marked as show stoppers and have only a few small projects remaining.

Gasifier Outage Work List #5
3/1/2000 – 8/7/2000
Undated 8/1/2000

WORK TO BE COMPLETED
De-inventory Gasifier
De-inventory Sulfator
Redesign Gasifier nozzles
Unplug Gasifier Coal Feed Tube
Remove Annulus from Gasifier
Gouge out cast refractory and replace with brick
Install Gasifier annulus
LASH Depressurization Filter design and repairs
Hot Gas Filter high level dump installation and design
Install escape ladder at Sulfator Solids Screw Cooler
Open and inspect Product Gas Cooler
Open and inspect Product Gas Trim Cooler
Open and inspect Hot Gas Filter
Open and inspect Gasifier
Open and inspect Fines Combustor
Open and inspect HRSG
Open and inspect baghouse
Rebuild Desulfurizer Feed Cyclone Fines Feeder and unplug transport
Repair spalled refractory in Gasifier
Install suction filter for Recycle and Recycle Gas Booster Compressors
Change gear sizes on Filter Fines Screw Cooler to run faster
Increase Recycle Gas Booster Compressor suction supply
Repair valve in LASH Removal Package
De-inventory Coal Feed Package
Install nitrogen blast nozzle at base of feed tube
Remove the mechanical stop from Syngas Temperature Control Valve
Change valve trim in recycle gas ring control valves
Repair hole in LASH Feeder transport line
Calibrate PDT's at Flare

Remove and inspect Syngas Module inlet strainer
Place blind in start-up air line to Desulfurizer Feed Cyclone
Open/close manway at top of Gasifier
Repair hole in Gasifier air/feed tube assembly
Replace refractory on Gasifier air/feed tube assembly

In addition to the work contained in the Outage List, three (3) Method Of Change Documents were completed for the changes made to the annulus: the new LASH Depressurization, Filter vent line, and the Flare. A complete safety, engineering, environmental, and operations review was performed on all three and documented. These documents have been given to the State Of Nevada.

Work remaining to complete before we can start-up includes finishing the installation of new Gasifier nozzles, which is expected to be completed 8/3/2000. Termination of the wiring and instrumentation on the Gasifier annulus will be completed this week. A new Hot Spot Detection System designed for the annulus will be completed. The final item is the vent line for the LASH Depressurization Filter. We are waiting for parts to complete the job. The parts are expected to arrive 8/3/2000.

Operations has begun to remove red tag clearances from the Gasifier Island as they are being signed off. The Control Room Operators were given the task of going over the Start-Up Procedure and making modifications to it. This has been completed and the Procedure is in the hands of consultants for final review.

Several of the Pinon Pine Project employees took a trip to the Wabash River Gasification Facility owned and operated by Global Energy. The trip was quite beneficial as the operators were able to meet the people who are now helping us with the project. In addition, they were taken for a tour of the facility and were able to interact with the operations staff. The plant was on line at 70% capacity at the time.

Start-up of the Gasifier will commence upon completion of the LASH Depressurization Filter vent line and follow up on all instrumentation and logic changes.

2.3.22 GASIFIER MONTHLY REPORT FOR THE MONTH OF: August, 2000

The beginning of the month saw us finishing up all of the work listed in the Outage Work List. Preparing for start-up of the Gasifier became the top priority. The Control Room Operators and consultants did work on the Start-Up Procedure. By the time the first weekend of August (5,6) approached, we were doing final work on the new LASH Depressurization Filter vent line. Once that project was completed, the clearances on the Gasifier were removed and start-up activities began.

On Monday, 8/7/200, Extraction air to the Gasifier was started and heat-up of the Gasifier refractory began. The new refractory in the walls and annulus will have to be heated up according to a new schedule given to us by Gasification Engineers. There is some concern about the probability of the Hot Gas Filter catching on fire as it has happened in the past at other units. To help prevent this from occurring, the stops have been removed from the Product Gas Temperature Control Valves so that all of the heat-up air flow will have to pass through both of the Product Gas Coolers before it goes on to the Hot Gas Filter.

Booster Air Compressor thermocouples failed and the machine had to be removed from service for repairs. The problem wound up being bad wire terminations and repairs were made. Heat-up of the Gasifier ceased during the time that the compressor was down. The 800°F-temperature hold on the refractory was completed before the machine was tagged out.

The inlet temperature to the Hot Gas Filter reached 400°F and concern was raised as to whether we could continue to heat up the Gasifier and not endanger the Hot Gas Filter. A sample of the char on the filters was sent to the Southern Research Institute for testing and it did not ignite, under atmospheric conditions, until 840°F. A sample of our fines and coal mixed together did not ignite until 630°. Orders were given to the Control Room Operators to continue and not let the inlet to the filter get above 550°F.

We began this start-up during the hot weather season and System Control gave the OK. Once we started, the Control Room Operators were instructed that the start-up will continue unless terminated by order of Plant Manager, Director, or Vice President.

Once heat-up of the unit started again, the Gasifier refractory was brought up to 800°F again for one hour and we would then proceed to test equipment. Problems with the Recycle Gas Booster Compressor arose at this time. The compressor would trip every time we tried to back pulse the Hot Gas Filter. The inlet pressure regulators to the machine were adjusted to try to prevent this from happening. The pressure controllers on the machine also were adjusted.

On August 10, 2000, the Gasifier was at 800°F and we raised pressure on the unit to 200 PSIG in order to test equipment for cycle time and logic. Leak checks on the entire structure were performed. Some problems with the LASH hoppers were encountered. While technicians worked on this problem, orders were given to the Control Room Operator to begin lowering pressure on the unit to prepare for work on the Grinder. Shortly before 1300 hours, smoke began emanating from the Flare Stack. The Control Room Operator checked the temperatures in F-501. Indications were that the filter was on fire. All air was immediately removed and nitrogen flow to the filter started.

The Gasifier was completely depressurized and tagged out so that the lower access door on the Hot Gas Filter could be opened up for inspection. Several broken candles were observed in the cone where the candle catcher is located. Start-up of the Gasifier was aborted at this time. Data from the start-up indicates there was some fuel in the Desulferizer Cyclone dip leg and it became fluidized when the pressure on the Gasifier was being reduced. This was the cause of the fire.

We allowed the Hot Gas Filter to cool off over an entire weekend to allow access. The Plant Engineer contacted Southern Company to get some direction on how to proceed. They have had “filter on fire” at their facility. We held a conference call with the Gasification Engineering staff to get a list of recommendations from them also.

Service air was rigged up to the Hot Gas Filter back pulse skid so that the filters and vessel could be cleaned as much as possible. When we went inside the filter, damage was apparent to the top tube sheets where the candles are attached. Westinghouse was asked to come to the site and take a look at it and give us their opinion. After the Westinghouse representative spent a couple days crawling around inside of the filter, he told us that the structural integrity of the unit did not seem to be jeopardized. We then agreed that repairs could be made and the filter could be readied for service again. The Westinghouse representative went back to Pittsburgh and had their metallurgist look at the pictures he took. They subsequently sent a letter of recommendation. Some shoring up of the filter assemblies was done as suggested in their letter.

During subsequent conferences with the Gasification Engineering staff, a method of heating up the Gasifier with nitrogen was proposed. This will entail putting line from the recycled gas header to the suction of the Booster Air Compressor. We could then circulate the nitrogen through the Start-Up Heater and to the Gasifier. This would prevent the earlier occurrence from ever happening again. All work required to see if this is viable for our application is being done.

As of the end of the month, all candles have been removed from the Hot Gas Filter, cleaning of the candles begun, and repairs being made to the upper tube sheets in the filter. Our plan is to stop all leak paths in the damaged tube sheets, replace all empty spots in the filter with cleaned or new candles, and try to start-up again. The nitrogen heat-up system will be installed, if viable, before the next attempt. Some figures for total restoration of the filter are being put together.

2.3.23 GASIFIER MONTHLY REPORT FOR THE MONTH OF: September, 2000

The beginning of the month saw the Gasifier out of service for repairs to the Hot Gas Filter. Mechanics continued to work inside of the filter and operators cleaned dirty candles. An estimate for total restoration of the filter was requested by the Director to see if the insurance we have would cover the damages. The total cost of repairing the filter will not fit under that scope.

A proposed cross tie from the Recycle Gas System to the Air System was proposed and design began. The purpose is to provide a way to heat up the Gasifier during cold starts using nitrogen in a "closed loop" design. The damage caused to the Hot Gas Filter would be avoided in the future.

A DOE representative came on-site to attend a meeting with us. A representative from Gasification Engineers was asked to come out and be there also. The topic under discussion was the future work plans of the Gasifier. Sierra Pacific Resources has final bids due for the divestiture of the Tracy Power Station by September 30, 2000. The continuance of pursuing another start-up of the Gasifier is not in their best interests. This was proposed to the representatives from the DOE and an agreement was reached. The new owners will sit down with SPR and the DOE to discuss the continuation of the project sometime in November of 2000.

A finalized Work Plan and associated schedule was drafted for approval. Cash flow to the end of the Cooperative Agreement was included. This information has been sent to the DOE for final acceptance.

Finally, the Final Technical Report for the project has an approved outline and work has begun on it. The report is due on November 1, 2000 for review by the DOE.

2.3.24 GASIFIER MONTHLY REPORT FOR THE MONTH OF: October, 2000

The Gasifier Team Leader spent the entire month of October working on the Pinon Pine Project Final Technical Report to the Department of Energy. This document is required by the contract that was signed by Sierra Pacific Resources with the DOE for the Clean Coal Technology Program. A rough outline of the document was agreed upon during a meeting held last month. Participants who helped in the compiling of information for the document are noted in the report.

Mechanics worked for a few days during the start of the month on the Hot Gas Filter. The damaged plenums are being repaired to the point that the installation of candle filters would be the next move. The mechanics were pulled off the job by the Combined Cycle outage during the middle of the month and have resumed work as of Monday, 10/30/00.

The Gasification User's Conference was held in San Francisco, California on October 9-11. The Gasifier Team Leader attended the conference.

Global Engineers are working on the final design for the Closed Loop Nitrogen Heat Up System for the Gasifier.

The Gasifier has been set up for the Winter weather. All of the vessels have been drained. The Nitrogen plant has been pickled. Two more trucks of nitrogen were ordered to keep the back-up tank from being empty.

2.3.25 GASIFIER MONTHLY REPORT FOR THE MONTH OF: November, 2000

The Gasifier was out of service the entire month of November, 2000 for modifications. Repairs to the damage caused inside of the Hot Gas Filter continued throughout the month. Design for the proposed “Closed Loop Nitrogen Heat Up” line was pursued by the engineers from Gasification Engineering.

The Hot Gas Filter repair work is quite extensive. Mechanics are welding plate metal over all of the burned out areas. All possible leak paths that may exist in the top candle clusters must be eliminated. A total inventory of all of the gaskets, bolts, and candle filters that we have on hand was taken to allow the ordering of extra parts, if needed.

The sale of the plant to Wisconsin Public Services was announced and the officers of the company came out on site to talk to all of us at a plant wide meeting. Talks involving the plant personnel involved with the Gasifier and WPS representatives were also held to determine the course of action to be taken from this point on. It was decided to pursue a test run of the Gasifier once the repairs to the Hot Gas Filter and the installation of the “Closed Loop Heat Up” line are completed.

In addition to the above verbal agreement with WPS, an insurance claim may be filed on the damage to the Hot Gas Filter to cover restoration costs at a later date. I have asked Jerry Bruck of Westinghouse to get an estimate of what four (4) new candle clusters for the Hot Gas Filter would cost. If the test run of the Gasifier proves that we can move forward with the project, total restorations of the Hot Gas Filter may be warranted.

Quite a lot of time was spent on the DOE Final Technical Report for the project. A rough copy of the report is being looked over by Don Geiling and Larry Rath. They have until December 1, 2000 to return comments to SPPCo so that the report can be finished up. Some comments by them were received on 11/30/2000 and work to finish up the report will begin again next month.

On 11/16/2000 we received a preliminary design package from Gasification Engineers for the "Closed Loop Nitrogen Heat Up System". After looking it over, all that will be required is a final drawing. On 11/28/2000, a pipe stress engineer retained by Gasification Engineers came on site and completed the design. Parts for the system can now be ordered and installation begun once the pieces arrive.

A Microsoft Schedule document detailing the next two months has been made up and sent to those concerned. Start-up of the Gasifier will begin, tentatively, at the beginning of the month of February, 2001. The goal for the start-up will be to run for 72 consecutive hours and prove that we can remove LASH from the unit.

2.3.26 GASIFIER MONTHLY REPORT FOR THE MONTH OF: December, 2000

The Pinon Pine Gasifier was out of service the entire month for repairs to the Hot Gas Filter and design of the new "Closed Loop Nitrogen Heat-Up" system. By the end of the month, the deign for the new system was complete, all parts ordered, and fabrication begun at off-site contractors facility. The repairs to the Hot Gas Filter are 98% completed.

2.4 Results of Start-Ups

2.4.1 Site Problem Report Log

As was mentioned in the Introduction, the initial start-up phase of the Gasifier Island was conducted by the SPPCo Project Manager, M. W. Kellogg, Foster Wheeler, and SPPCo employees. The efforts were documented in a process called Site Problem Reports (SPR). The following table is a representation of all the work performed during the period of 1997 – 1998.

SITE PROBLEM REPORT LOG

SPR #	Date	Problem
1	7/22/97	Safety walkdown items.
2	7/22/97	Hazardous gas monitor horns not loud enough.
3	10/20/97	Weather damage to gas monitors.
4		Repair water damage to compressors.
5	7/22/97	Atlas-Copco compressors have logic problems.
6	7/22/97	Install nitrogen bypass around back up pump.
7	7/22/97	Voided.
8	7/22/97	Transmitter and regulators provided were wrong.
9	7/22/97	Fines and LASH Feeders binding in enclosures.
10	2/26/97	HRSG sootblowers.
11	7/22/97	Consultant for Clarifier.
12	9/1/96	Clarifier warranties.
13	7/22/97	Soda Ash system at Clarifier.
14	7/16/96	Demineralizer warranties.
15		Demineralizer vessel drainage.
16	7/22/97	Chemical cleaning of Closed Loop Cooling Water system.
17	7/22/97	24V DC Power Supply system.
18	1/24/98	Cooling Tower anchor bolt corrosion.
19	1/24/98	Gasifier area lighting.
20	3/13/97	Piping support spring and snubber.
21	10/21/97	Gaitronics phones.
22	10/22/97	Insulation.
23	10/30/97	Plant site clean up.
24	4/7/97	Steam line piping support.
25	4/7/97	Start up air temperature low due to lack of insulation.
26	4/11/97	Orifice sizing in the Recycle Gas Purge system.
27		Missing from file.
28	9/23/97	Drum level trips.
29	9/20/97	Photo cells for plant lighting.
30	11/22/97	Coke Transport system header Ab-Resist piping.
31		SPR 31 – 47 missing from file.

47		SPR 31 – 47 missing from file.
48	9/30/97	Run indicator lights (red) on MCC breakers.
49	9/30/97	Filter Fines Screw cooler leaking at packing.
50		Missing from file.
51	5/20/97	Convert Waste Silo discharge for enclosed containers.
52	5/20/97	Flare line crossing over electrical cable trays.
53	5/24/97	Gasifier logic.
54	5/23/97	Booster Air Compressor shaft position probes.
55	5/23/97	Six instruments located too close to high temperature pipe.
56	5/28/97	Changes at the Nitrogen Plant.
57	5/31/97	Valve failures in Coal Feed Package.
58	6/2/97	Install manual vent valve in Coal Feed Package.
59		Logic for Coal Feed Package. Blew out the rupture discs.
60	5/28/97	Install gas monitors near Recycle Gas Compressor.
61	6/3/97	Paving covering communication vault.
62	6/11/97	Static electricity grounds for dust collectors.
63	6/16/97	Level transmitters on surge vessels.
64	6/14/97	Recycle and Recycle Gas Booster Compressor trip switches.
65	6/14/97	Relocate the LASH Feeder start switch.
66	6/16/97	CEM for Unit 4 stack.
67	6/24/97	Install concreted guard posts around vulnerable piping.
68	6/21/97	Change nitrogen trip valves to fail open status.
69	6/27/97	Regenerator Air Heater switch permissive changed to flow.
70	6/27/97	Replace worn elbows in coke and limestone lines.
71	7/2/97	Coal handling Baghouse static grounding.
72	7/7/97	Install rupture discs in Coal Feed Package.
73	6/19/97	Void.
74	7/8/97	Repair crack in conveyor Baghouse structure.
75	7/9/97	Baghouse blower support structure.
76	6/26/97	Bury copper ground connectors.
77	7/16/97	Reroute the exhaust from steam safety.
78	7/22/97	Coal discharge from Coal Screen uneven.
79	7/22/97	Dust collection problem.
80	7/23/97	Change seal gas pressure to a PDIC.
81	7/29/97	Gasifier Baghouse static grounding.
82	7/29/97	Install pressure control Air Dryer.
83	7/30/97	Sulfator Air Compressor motor short.
84	7/30/97	Fines Combustor trip logic.
85	7/31/97	Nitrogen supply to suction of Recycle Gas Booster Comp.
86	7/31/97	Install Nitrogen bottle racks for valve seals.
87	7/31/97	Install moisture protection for air compressors.
88	7/31/97	Damper control for Start Up Air Heater.
89	8/1/97	Access to Waste Silo.
90		Missing from file.

91	8/4/97	Install isolation valve for pressure relief.
92	8/11/97	Phillips Petroleum sorbent.
93	8/12/97	Matrix I, II, III wiring changes.
94	8/14/97	Gasifier Island lighting and receptacle conduits.
95	8/14/97	Staircase at Stacker/Reclaimer.
96	8/19/97	Install moisture drain on Flare.
97	8/21/97	Install heat trace on exposed instruments.
98	8/21/97	Install moisture drain on Flare.
99		Void.
100	8/25/97	Install protection for compressors from elements.
101	8/21/97	Fire monitor station freeze protection.
102		Void.
103	8/28/97	Steam drain header weep holes.
104	8/27/97	Alter dust collection at Crusher Tower.
105	8/29/97	Install vent on Booster Air Compressor Surge Drum.
106	8/29/97	Oxygen analyzer on outlet of Fines Combustor.
107	8/29/97	Fines Combustor control panel access.
108	8/29/97	Recycle Gas Booster Compressor maintenance accessibility.
109	9/2/97	Work required to make design field correct.
110	8/30/97	Integrated Plant Design Hazard Review.
111		Missing from file.
112	9/4/97	Coal Feed Isolation Valve carbon steel insert.
113	9/9/97	Rubber seal between Coal Feed Surge Bin and vibrator.
114		Missing from file.
115	9/6/97	Change the design for the limestone.
116	9/18/97	Relocate the Flare.
117	9/18/97	Gasifier Steam Drum vent line relocated.
118	9/18/97	Piping corrections to Water Treatment systems.
119	9/19/97	Syngas Module Gas detectors.
120	9/20/97	Hot ember detectors for conveyors.
121	9/19/97	Sorbent unloading pump vacuum.
122		Missing from file.
123		Missing from file.
124		Missing from file.
125	9/23/97	Trip indication on DCS for conveyors.
126	9/25/97	Install valve on Sulfator clean-out nozzle.
127	9/26/97	Roof drain for the stack.
128	9/30/97	Coal conveyor breaker overload relays.
129		Missing from file.
130	10/1/97	Insulate pressure equalization lines.
131	10/8/97	Fire in central column of Stacker/Reclaimer.
132	10/10/97	Hot Gas Filter Backpulse Skid valve seals.
133	10/16/97	Install lightning rods on Cooling and Waste Evap. Towers.
134	10/14/97	Insulate extraction air valve.

135	10/17/97	Syngas flow transmitter sensing line.
136	10/20/97	Location of Stacker/Reclaimer on display.
137	10/20/97	Dust emissions from conveyors.
138	10/20/97	Coal Unloading Conveyor belt limit switches.
139	10/20/97	Coal handling bin level indicators.
140	10/20/97	Dust and coal collecting on top of coal silo.
141	10/17/97	Start up cleaning and painting.
142	10/20/97	Nitrogen plant liquid recovery.
143	9/25/97	Relocate fuel gas line to Fines Combustor.
144	10/29/97	Missing insulation.
145	11/3/97	Void.
146	11/5/97	Bad cable to the Crusher.
147		Void.
148	11/5/97	Cross tie line to Waste Silo
149	11/6/97	Stacker/Reclaimer safety items.
150	10/29/97	Nitrogen plant normal and emergency power supplies.
151	11/4/97	Monitor differential pressure across Adsorber.
152	11/7/97	Derime Heater Breaker.
153	11/10/97	Empty material from Sulfator to Waste Silo .
154	11/11/97	Raw Coal Receiving Feeders.
155	10/14/97	Accessibility to Gasifier battery limit block valves.
156	10/3/97	Stabilize HRSG vent line.
157	10/7/97	Gasifier Steam Drum level transmitter.
158	11/17/97	Void.
159	11/17/97	Nitrogen Plant freeze protection.
160	11/19/97	Syngas line warm up valve.
161	11/21/97	Nitrogen plant back up pump seal.
162	12/5/97	CEM and DCS connection.
163	11/21/97	Gasifier insulation punchlist.
164	12/5/97	Nitrogen plant Expander lube oil pressure.
165	12/5/97	480-volt breaker indications.
166	12/5/97	Fines Combustor control valves.
167	12/10/97	Install liquid nitrogen recovery tank.
168	12/11/97	J-Box wiring not rated for proper service.
169	12/4/97	Conveyor start horn indication.
170	12/11/97	Flare valves noise level.
171	12/20/97	Pressure control valve broken handwheel.
172	12/20/97	Flow meter for calibrating Gas Chromatograph.
173		Missing from file.
174	12/30/97	Ash feeder isolation valve damaged.
175	12/30/97	Trip acknowledged pushbuttons in control room.
176	12/31/97	Transport line instrumentation.
177		Missing from file.
178	1/2/98	Recalibrate safety valve settings.
179		Missing from file.

180	1/8/98	Flare valve actuator removal.
181	1/12/98	Vacuum truck to remove material from vessels.
182	1/12/98	HRSG hopper solids removal.
183	1/13/98	Sulfator Cyclone dipleg.
184		Missing from file.
185	12/12/97	Coal Feed Package material removal.
186		Missing from file.
187		Missing from file.
188	1/21/98	Upgrade material composition of valve.
189	1/21/98	Boiler feedwater temperature indication.
190		Missing from file.
191	1/22/98	Heat Transfer Fluid back pressure controller.
192		Missing from file.
193	1/15/98	Sorbent Regeneration Air Heater failure.
194	1/27/98	Void.
195	1/28/98	LASH Feeder gas sensor and speed sensor.
196	1/29/98	Install indicator gages for the valve seals.
197	1/29/98	Inspect all Gasifier Island vessels.
198		Missing from file.
199	1/30/98	Sulfator Solids Screw Cooler bound up.
200	1/28/98	Route steam line drains to floor drain.
201	1/29/98	HRSG leaking flue gas.
202		Missing from file.
203	1/30/98	Vacuum truck to remove material from vessels.
204		Missing from file.
205	2/3/98	Recycle Gas Compressor problems.
206	2/3/98	Differential pressure control valve.
207	2/3/98	Blast nozzle in the LASH Feeder discharge.
208	2/5/98	Flare High Energy and Flame Front Ignition Panel.
209	2/7/98	Nitrogen plant Expander lube oil pump.
210		Missing from file.
211	2/6/98	HRSG valve leaks.
212	2/9/98	Sulfator Baghouse Screw Conveyor leaks.
213	2/9/98	Purge rotameter failed.
214	2/10/98	Install drain valves in feedwater line.
215	2/10/98	Instrument purge strainers.
216	2/12/98	Diverter valve leaking (worn out).
217	2/13/98	Clean out Gasifier nozzles and piping.
218	2/13/98	Portable fire extinguisher hangers.
219		Missing from file.
220		Missing from file.
221	2/17/98	Vessel operating number for State of Nevada.
222	2/9/98	Decrease Coal Feed Isolation Valve to 10 seconds.
223	2/9/98	DCS cycle counter for solids handling packages.
224	2/9/98	LASH and Fines Feeder packing.

225	2/19/98	Pressure relief valve has frequent cycling.
226	2/14/98	Install power receptacle on Silo structure.
227	2/17/98	LASH Feed Bin sampling system unsafe.
228	2/23/98	Heat Transfer Fluid Backpressure Controller.
229	2/27/98	Transport Desulfurizer J-leg aeration nozzles.
230	3/3/98	Operating upsets with Sulfator.
231	3/4/98	Damaged temperature elements on HRSG.
232	3/4/98	Fines Combustor Air Compressor noise exceeds limits.
233	3/9/98	Gate valve for instrument air to Coal Feed package broken.
234	3/11/98	No way to remove the solids from J-leg.
235	3/11/98	Solids Removal Bins will cycle without transport air.
236	3/12/98	Gasifier elevator smoke detector.
237	3/13/98	Blown rupture disc on LASH Feed Bin.
238	3/11/98	Convert Limestone Feeder to variable speed drive.
239	3/14/98	Install locks on vales per EFD indication.
240	3/20/98	Install purge air to HRSG sootblowers.
241	3/21/98	Reinforce Gasifier support beams.
242	3/21/98	Vacuum truck to remove fines.
243	3/22/98	LASH Feeder blade tip damage.
244		Missing from file.
245		Missing from file.
246		Missing from file.
247	3/24/98	Analyzer probes for Syngas streams are plugging up.
248		Missing from file.
249		Missing from file.
250	3/30/98	Install "candle catcher" in Hot Gas Filter cone.
251	3/30/98	Filter Fines Feed Bin rupture disc blown.
252	3/31/98	Fire in coal dome. Pile worked to put it out.
253	4/1/98	Sweated copper tubing to some instrument air coming apart.
254		Missing from file.
255		Missing from file.
256		Missing from file.
257	4/7/98	PI plant history monitoring capabilities.
258		Missing from file.
259	4/13/98	Install adapter to vacuum out Flare line.
260		Missing from file.
261	4/10/98	High-High Level Horns for Coke and Limestone silos.
262		Missing from file.
263	4/18/98	Extraction Air line failure.
264	4/20/98	Plugged fines distributor to Fines Combustor.
265	4/20/98	Install blast nozzle in fines transfer line.
266	4/22/98	Relocate isolation valves.
267	4/24/98	Flare header heat tracing.
268	4/24/98	Orifice plate to nitrogen purge drum resized.
269	4/25/98	Vacuum truck to remove material from several vessels.

270		Missing from file.
271	4/25/98	Fines Combustor assist burner tip replaced.
272	4/26/98	Filter fines Feed Bin rupture disc line cleanout installed.
273	4/28/98	Blast nozzles installed in LASH feed lines.
274	4/28/98	Install newly rated rupture discs in Filter Fines Feed Bin.
275		Missing from file.
276	4/8/98	Reroute discharge line for safety.
277	5/8/98	Install pressure regulator in nitrogen to compressor suction.
278		Missing from file.
279	4/7/98	Stack roof drains damaging CEM equipment.
280	5/14/98	Change the VFD capability for screw coolers.
281	5/26/98	Move coal from dome to outside pile.
282		Missing from file.
283	5/3/98	Heat Transfer Pump failure.
284	6/6/98	Gasifier area gas monitors.
285	6/7/98	Hot Gas Filter ceramic candle filter failure.
286	6/7/98	Recycle Gs Compressor vibration probe support brackets.
287	6/4/98	Replace lighting fixture in the Syngas module.
288	6/15/98	Safety failed. Rebuild valve.
289	5/3/98	Replace the HTF pump with Gould pump.
290	6/18/98	Filter Fines Depressurization Filter inadequate.
291		Missing from file.
292	6/19/98	Clinker Grinder bound up.
293	6/19/98	Fines Combustor Fine Distributor plugged.
294	6/21/98	LASH Feeder seized up.
295	6/24/98	Refractory spalling in Gasifier.
296	6/25/98	HRSG tube leaks.
297	6/26/98	Solution for the Filter fines Feeder problem.
298		Missing from file.
299	6/6/98	Sulfator ash transport line failure.
300	7/8/98	Hydro clean recycle gas piping system.
301	7/8/98	Flare heat trace monitoring.
302	7/9/98	Sandblast and coat Flare and Purge Drum with primer.
303	7/14/98	HRSG sootblower warm up solenoid installation.
304	7/14/98	High rate nitrogen flow meter failure.
305	7/14/98	Replace damaged parts to Stacker/Reclaimer due to fire.
306	10/13/98	Heat tracing to Flare header low temperatures.

Start-up of the Gasifier was attempted on several occasions and M.W. Kellogg provided documentation. The following summaries of Gasifier operation depict all start-up events that occurred between January18, 1998 and July1, 1998.

On Sunday January 18, 1990 the first heat up of the Gasifier began. Once addition of Coke Breeze and Limestone occurred, temperature ramp rates that exceeded 100°F were experienced. The grid temperatures didn't fluctuate very much and indications on the DCS indicated that there was no fluidization of the bed in that area. Velocities in the air and feed tubes were calculated and it was determined that the flows were too low to adequately mix the Gasifier bed. Couple this with the fixed bed notations from the Gasifier Pressure Differential Indications and it was obvious that poor circulation was occurring.

In an effort to limit combustion in the Gasifier, operations shut off the Coke Breeze addition. This subsequently caused a Gasifier Type II Shutdown, which shuts off all gasification air and transport flows. The term used for this is slumping the bed. The recycle gas still going into the Gasifier via the nozzles apparently still contained some excess oxygen as combustion in the grid area continued. The removal of the bed material to the Sulfator was attempted but a failure of the BN-508 isolation valve occurred.

Conclusions from this run of the Gasifier stem from the formation of clinkers in the bed. In order for this to occur, inadequate mixing of the material must happen. The data suggests that the middle sparger ring ingested oxygen into the process. Sintering could also have occurred in the lower cyclone dipleg where velocities would be lower due to high impedance of flow. Therefore, much higher jet velocities and flows through the grid rings are needed for subsequent start-ups.

On March 20, 1998 the Gasifier was loaded with 38 tons of Coke Breeze and 32 tons of limestone. Extraction air was started to the Gasifier and heat up began. Once the freeboard temperatures reached approximately 300°F the temperatures began to rise rapidly. Extraction air flow was reduced to try and control the temperature ramp rate. Steam was introduced to the Gasifier bed at 1250°F and the temperatures cooled. Coal feed began and once the Gasifier outlet temperature reached

1700°F the temperatures leveled off. The differential pressure across the Hot Gas Filter rose to 160" of water indication that solids carry over from the Gasifier bed was occurring.

A High-High level was achieved in the Filter Fines Collection Hopper and the Filter Fines Screw Cooler tripped. The LASH feeder tripped on motor overload and could not be restarted. Two Gasifier Type II Shutdowns occurred, one on low level in the Gasifier Steam Drum and a Filter Fines Rupture Disc alarm. The Gasifier was shut down due to solids removal problems.

Following operation of the Gasifier, several things were found. The Filter Fines Screw Cooler was jammed and would not turn. Broken candle filter from the Hot Gas Filter were caught in it. Pieces of refractory had become caught in the blade of the LASH Feeder and inabled it. The candle filter breakage in the Hot Gas Filter was determined to be caused by a high level of material in the filter cone. The Filter Fines Removal System failed to operate as designed.

Several observations during the start-up:

- Coke Breeze ignition occurred at approximately 400°F.
- The Gasifier temperature ramp rate was excessive. The heat up went from light off to 1500°F in 90 minutes.
- Temperatures in the grid area exceeded 200°F during one of the Type II Shutdowns. The possibility of large clinkers forming during this period were unfounded.
- High annulus temperatures were attributed to overfluidization in the region.

On April 10, 1998 a Sorbent circulation test was performed on the Desulfurizer at a pressure of 100 PSIG. The test began with the extraction air flow to the Desulfurizer (filled with 39,000 pounds of sorbent) through the inlet of the Desulfurizer Cyclone. Flows through the various nozzles in the Desulfurizer were set at design rates. Extraction air flow was increased to

20LB/sec solids circulation began and the two differential pressure indications on the Desulfurizer indication level. Increasing the extraction air flowrate did not change the circulation of the solids or the level indications. The test was deemed a success.

On June 2, 1998 the Gasifier was once again put through another start-up attempt. A 50/50 mixture of Coke Breeze and Limestone was loaded into the Gasifier. Extraction air flow was initiated and heat up occurred. Light off of the bed was initiated and the temperature ramped to 1700°F with the addition of steam and coal feed at about 1200°F. Syngas of acceptable quality was produced for about a five hour period during the run.

Once again, several problems with the Gasifier systems occurred:

- The Limestone and Coal Feeder tripped four different times.

- The Filter Fines Collection System failed to operate as designed.

- The Filter Fines Screw Cooler tripped several times on High-High level in the Filter Fines Collection Hopper.

- The Fines Combustor operation was sporadic.

- The Hot Gas Filter eventually achieved an extreme differential pressure and a Gasifier Type II Shutdown occurred.

- Gasifier temperature ramp rates are excessive and damage to refractory is occurring.

- The level indication in The Hot Gas Filter is inadequate.

- The nitrogen system pressure declined to 188 PSIG during one point of operation. This could prove to be a problem at higher Gasifier loads.

On June 5, 1998 Gasifier operations resumed. During heat up of the Hot Gas Filter, black plume emitted from the Flare. It was assumed at the time that some fines had lodged in the Flare header from the previous operation. The Gasifier bed was lifted and light off occurred. The run lasted for only four hours due to fines emissions from the Flare and high vibration of the Recycle Gas Compressor. Once again, problems have been chronicled:

- The Coal Feed System encountered logic and cycling problems.

- The Gasifier temperature ramp rate was once again much too fast. Efforts to lower extraction air flow to minimum levels proved to be unsatisfactory.

- Several alarms on the Recycle Gas Compressor where no previous history exists.

- Broken candles exist in the Hot Gas Filter again. The impeller in the Recycle Gas Compressor was eroded and had to be changed.

On June 17, 1998 operation of the Pinon Gasifier resumed. During the shutdown period, all of the candle filters in the bottom tiers of the Hot Gas Filter were removed. This was done to prevent the further breaking of the candles until a means of detecting level in the vessel could be established.

The Gasifier was lit off with existing bed material. The initial light off temperature was much higher than a straight Coke Breeze/Limestone bed. This was attributed to volatilization of the bed. The Gasifier achieved 140 PSIG operations for the first time. The temperature ramp rate proved to be much lower than previous runs but was still too fast. In addition, the pressure drop across the Hot Gas Filter was much higher than previous due to the missing candles. This caused concern for the life of the refractory.

The Gasifier annulus section runs much hotter than designed. It is assumed that the flows through the rings in this area are too high, causing mixing. The Filter Fines Removal System failed horribly once again due to several maladies. The capacitance level probes located in the hoppers do not work consistently. False level indications cause the cycling of the package to be sporadic.

On June 30, 1998 Gasifier operations occurred after an outage. Several pieces of refractory were removed from the annulus during the shutdown. Some of the material in the Gasifier bed was withdrawn though the LASH System. A decision was made to continue with operation without inspecting the refractory. Work was performed on the Filter Fines Removal System also.

The Gasifier was charged with about 49 tons of Coke Breeze and 33 tons of Limestone prior to introduction of extraction air. After lightoff and an operating period of about 80 minutes, the Gasifier bed was slumped due to pressure taps becoming plugged in the Filter Fines Removal System. The hoppers would not cycle correctly. The taps were rodded out and operations resumed. The Fines Combustor operation ceased several times from high outlet temperature during this period. This eventually caused a high level in the Filter Fines Hoppers and operations ceased.

As in previous runs of the Gasifier, the annulus temperatures exceeded the 500°F temperature by design. More research into this phenomena will be required. It is assumed at this time that gas flow to the Grinder and LASH Feeder seal may be causing fluidization in the area. The fines samples removed from the Filter Fines Feed Hopper show that the composition of the material changes with time as the Gasifier bed transitions from Coke Breeze to Coal.

On July 1, 1998, the position of Gasifier Process Specialist was created. He took over the operation of the activities. By this time, Foster Wheeler was no longer on site. Most of the engineering staff from M. W. Kellogg were sent home. The Site Problem Report process continued only to the extent of tracking Capital expenditures. All other work on the Gasifier was carried out through the company work order system.

Below is a documentation of each start-up attempt of the facility from the July 1, 1998 date mentioned above until the end of the agreement. There will be a Start-Up Report, Start-Up Problem Report, and associated Outage Work List when warranted.

2.4.2 Start Up Report #1

START-UP OBJECTIVES AND RESULTS 9/22/98

Start-Up Objectives
The goal of this start-up was to run the unit for sufficient time to evaluate The Big Three issues identified in the June start-ups. These issues were identified as:

A. Poor level indication in Hot Gas Filter.

B. Poor level indication in Filter Fines Removal Package.

C. Over temperature/flame out trips occurring in Fines Combustor.

Equipment modifications made to remedy the Big Three issues were tested during the start-up and are described below:

A temperature element "tree" was installed in the Hot Gas Filter to help determine level of fines in the cone.

In the Filter Fines Removal Package nuclear level gages were installed in the Filter Fines Depressurization Bin and vibrating level detectors were installed in the Filter Fines Feed Bin.

A Flue Gas Oxygen Analyzer was put into the outlet ductwork of the Fines Combustor and the unit controls were tuned to outlet exhaust temperature.

Results Of Start Up

The following describes the results obtained from the start-up in regards to the Big Three issues:

The Temperature Element "Tree" in the Hot Gas Filter performed very well. Operators had indication of where the level was at all times. The nuclear device detected level, also.

Both level detection devices installed in the Filter Fines Removal Package worked well. The vibrating detectors gave instantaneous level indication and the nuclear devices had a shot time delay.

The Fines Combustor performed throughout the start up period without a trip.

General Start-Up Results

Start-up was aborted due to inability of BN504 to depressurize. This caused a build up of fines in F501 and the Gasifier bed was slumped. The overall run time was sufficient to obtain results from level probe operation.

There was no data on the Syngas due to the Gas Chromatograph not being turned on.

Post Start-Up Findings

Formation of slag was found inside of the Fines Combustor. In addition, the expansion joint between the Fines Combustor and the HRSG failed.

Sulfator Screw Cooler began leaking and a hole was rubbed into the shell.

Sulfator Solids Cooler was found to be full of "set up" material. Speculation as to the cause of this was that the leak allowed moisture into the vessel.

The Gasifier Feed/Air tube assembly was removed for inspection and damage was found to Nozzle "E" which supports the Feed/Air tube.

GASIFIER START-UP PROBLEM REPORT

Start-Up Number: 1 Date: 9/16/98 Days Duration: 6

Problem Incurred	Solution Rendered
1. FD301 coupling sheared.	Feeder coupling repaired. WO# 98-T4-1652
2. Solids diverter valve malfunctioned.	Valve removed and replaced with different set up. SPR# PP 183
3. Boiler feedwater backed up into The 70# nitrogen system.	Drained pipes. Emptied all wet inventory in Sulfator.
3. Leak in Syngas line at Syngas module.	Leak repaired. Gasket replaced in flange. WO# 98-T4-1660
4. Plugged transmitter in FD401 transport line.	Operators set control valve in manual.
5. C902 tripped due to water in 70# nitrogen line to seals.	Seal line drained and compressor restarted.
6. BN601, BN607, and transport line plugged with wet material.	Mechanics opened up the line and vessels and cleaned them out.
7. FD301 tripped twice when material fell on it. This caused Gasifier Type II shutdown.	Operators had to restart all equipment in order to continue to refuel the Gasifier.
8. Flare Purgematic flow transmitter malfunctioned.	Transmitter recalibrated. WO# 98-T4-1666
9. FD503 fluffing nozzles plugged. This caused feeder to trip often.	Fluffing nozzles unplugged.
11.F503 depressurization filter for BN504 failed to allow the bin to cycle often enough.	Operators had to manually bypass the filter. This is what eventually caused the start-up to be aborted.
12.H602 Fines Combustor blew an expansion joint. This happened after the Gasifier	Work is in progress.

bed was slumped.	
POSITIVE NOTES	**RESULT**
1. Gasifier performance.	This is a given. Control of the Gasifier has been relatively easy for operators.
2. Vibration level probes.	Performed flawlessly.
3. Nuclear level probes.	Performed flawlessly.
4. Fines Combustor operation.	Performed through all possible scenarios.

2.4.3 Start-Up Report #2

Goals Of Start-Up And Evaluation

The overall objective of this start-up was to fire the Gasifier and run for as long a period as possible. Some operational issues that still exist are the removal of LASH from the Gasifier annulus, the operation of the Desulferizer/Regenerator, and firing the Sulfator.

Results Of Start-Up

The Gasifier was lit off at approximately 1600 hours on 12/17/98. The run lasted for two hours and was aborted due to the Filter Fines Depressurization Bin not depressurizing in a timely manner. The Depressurization Filter has plugged with fines. To compound this situation, the Fines Combustor was tripped on high temperature. By the time that fines were removed from the Hot Gas Filter and the Filter Fines Removal Package, the nitrogen tank had reached a low level. Start-up was officially aborted at this time.

General Start Up Results

The operation of the Gasifier was very smooth and controllable. The Fines Combustor worked quite well once the fines were began and the temperature leveled out. The over temperature trip was caused by too much feeder speed.

Post Start-Up Findings

We found some nitrogen leaks and stopped them. This contributed to the large usage that resulted in the low level that eventually ended the Gasifier attempt. Subsequent start-ups were halted due to extremely cold weather and system demand.

GASIFIER START-UP PROBLEM REPORT
Start-Up Number: #2 Date: 12/17/98

Problem Incurred	Solution Rendered
Filter Fines Depressurization Bin inability to depressurize.	Filters will be removed from Depressurization Filter.
Fines Combustor over temperature trip.	Operating parameters put out by vendor distributed to Control Room Operators.

2.4.4 Start-Up Report #3

Start-Up Objectives

The objectives of this start-up were to test if the removal of the filters from the Depressurization Filter would allow the Filter fines Depressurization Bin to depressurize readily. Up to this point, we have not been able to determine if the package could keep up with the fines production adequately. Once this was determined, the goal was to progress with the start-up, raise pressure in the Gasifier, move onward to LASH removal from the Gasifier annulus, fire the Sulfator, and put the Desulferizer/Regenerator in service.

Results Of Start-Up

The Filter Fines Removal Package performed well. The depressurization of the Filter Fines Depressurization Bin occurred readily and without delay. The Gasifier lit off and was controllable. Coal feed lasted for approximately three hours. Gasifier pressure was raised to 120 PSIG for a period of two hours before the start-up was aborted due to failure of the expansion joint in the Fines Combustor.

Post Start-Up Findings

Upon inspection of the expansion joint in the Fines Combustor by vendor and consultant, it was determined that accumulating unburned fines caught fire and burned out the material in the joint. In order to remedy this in the future, an Inconel sliding plate will be installed to cover the joint and keep material from becoming entrained in the mesh material. The Gasifier performance is quite acceptable. The Fines Combustor baghouse was opened up for inspection and collapsed bags were found. Looking at the data collected, the baghouse differential pressure steadily climbed beginning at 1945 hours and reached 10.5” at 2030 hours. The Fines Combustor temperature began swinging shortly afterward. The bags will be repaired and the back pulsing will be continuous. New temperature indications will be installed into the Fines Combustor to aid in the operation.

GASIFIER START-UP PROBLEM REPORT

Start-Up Number: #3 Date: 1/4/99Days Duration: 1

Problem Incurred	Solution Rendered
Bed in Gasifier would not lift.	Decreased pressure to allow bed to "burp". This freed it up and fluidization began.
Several logic problems.	Fines rupture disc flow alarm. Solids Removal Bin fail to pressurize. I&C technicians worked to alleviate.
Temperature control of Fines Combustor erratic at high fines flow rates.	After inspection of internals of Fines Combustor during shut down, it was determined that the current temperature indication is inadequate. New TE indications will be installed.
Fines Combustor expansion joint failure.	Expansion joint vendor was called out to inspect the joint. It had burned out due to accumulation of solids in the joint that caught on fire. An Inconel slide plate will be designed to cover the joint and keep solids out.
Gasifier ring nozzles plugging up.	When the bed is slumped in the Gasifier, solids are entrained in the nozzles. We have installed modifications to all nozzles so that they can be individually unplugged if necessary.
Collapsed bags in baghouse.	Repairs will be made. The back pulsing was in demand. Next start-up, will be continuous. New TE indication in Fines Combustor should help operation.
Items Of Note	Positive Results
Operation of Filter Fines	Removal of the filters from the

Removal Package.	Depressurization Filter and venting to the flare header allowed the package to cycle. We were able to keep up with the fines production.

2.4.4 Start-Up Report #4

Start-Up Objectives

- Burn fines from the Filter fines Removal Package, test new temperature indications installed, tune controllers.
- Light off Gasifier, bring up to temperature and stabilize, raise pressure and load in increments until shut down occurs.
- Start removal of LASH from annulus area, inventory Sulfator, and fire Sulfator. Place Desulferizer/Regenerator into service.

Results Of Start-Up

The Fines Combustor experienced several operational problems during the onset of the start-up. The temperature controls would respond too quickly to slug flow of fuel and the unit would trip on Fines Combustor Air Compressor low discharge pressure. A technician tuned the controls and it began responding much better. All fines accumulated in the Filter Fines Removal Package from the last start-up were burned to allow room for the Gasifier start-up.

The Gasifier lit off after several hours. Heat-up was very slow and the Start-Up Heater needed to be put into service in order to gain enough temperature to ignite the bed. Operators were able to gain control of the process. Some troubles were experienced during the step that requires steam flow through the rings to begin. Flow transmitter and valve problems ensued. A technician worked on these problems.

The step that requires LASH to be removed from the annulus area of the Gasifier was not achieved during this run.

The Desulferizer/Regenerator was not put into service during this run.

Gasifier bed was slumped twice during the run due to high high level alarm in the Hot Gas Filter. Fines were burned out of filter to make room for another attempt both times.

Gasifier run was aborted after 25 hours due to excessive emissions from Flare stack. The Recycle Gas Booster Compressor tripped on rod drop indicator and would not clear and restart.

The baghouse screw trough has some leaks in the gasketed areas.

Post Start-Up Findings

Emissions from Flare have blackened the ground in the area surrounding the Flare. Environmental Affairs has been called out to site to inspect and report to State Of Nevada.

Hot Gas filter was opened up for inspection. The fines level was at the inspection door just above the 3rd level decking. The Filter Fines Screw Cooler was bound up and would not turn. Operators began vacuuming out the Hot Gas Filter. Hi-Vac bags plugged up, so mechanics hooked up cheater to the Filter Fines Screw Cooler sprocket and used chain fall to break it loose. Motor was started and fines were removed from Hot Gas Filter until The Filter Fines Collection Bin high level occurred. The candle catcher is partly uncovered and no evidence of any damage in the Hot Gas Filter exists.

The Recycle Gas Compressor suction spool piece was removed for inspection of the compressor impeller. No damage was found.

Recycle Gas Booster Compressor cylinder heads were removed and the LP cylinder had worn out rings. This brought in the rod drop indicator. The HP cylinder had worn rings, piston, and cylinder. New parts are ordered and a factory representative will be called out to inspect and analyze.

The baghouse was emptied and the screw trough gaskets were sealed with silicone.

GASIFIER START-UP PROBLEM REPORT

Start-Up Number: 4 Date: 1/27/99 Days Duration: 5

Problem Incurred	Solution Rendered
H602 Fines Combustor Flame Out.	Controllers were tuned to smooth out the operation.
Steam Ring Flow Indications Not Registering.	Instrument Technicians worked on transmitters.
Upper Steam Ring Nozzles Plugged.	Operators Will Blast Nozzles During Shut Down Period.
BN503 Fines Bridging In Vessel.	Fluidizing Nozzles Will Be Checked For Plugging.
Smoke Emissions From Flare.	Report Filed With State Of Nevada.
SG401 Drum Level Control.	Instrument Technician Tuning Controls.
BN608 Trips Intermittently.	Bin Is Too Small And Will Be Resized In The Future.
E501 Bound Up And Won't Turn.	Used Cheater Bar And Chain Fall To Break It Loose.
Large Emission Of Soot From Flare.	Shutdown Immediately. New Filter For F503 Will Be Engineered And Installed Before Next Start Up.

2.4.6 Start-Up Report #5

Start-Up Objectives

The goals and objectives of this start-up were to test the new additions to the Depressurization Filter vessel on the Filter Fines Removal Package. We added a second filter assembly to the unit to allow more surface area for filtration. It is our belief that this would help stop the plugging of the filter as had happened in the past. In addition, a method of back pulsing the filters has been installed.

Vibrators were added to the cone sections of the bins to cause free flow of material and stop bridging in the bins. The last start-up proved this to be a serious problem. The goal of each start-up is to achieve the maximum load on the Gasifier and remove LASH from the annulus area. This is the next milestone.

Results Of Start-Up

On 3/31/99, shortly before midnight, the Gasifier bed combustion began. The Gasifier remained in operation for a short period. The bed had to be slumped to catch up with fines that had backed up in the Hot Gas Filter. The new back pulse valve that we installed in the Depressurization Filter had stuck open and the bins in the Filter Fines Removal Package would not cycle. I&C had to repair the problem. At approximately 0700 hours on 4/1/99, the Gasifier bed was lifted for a second time and combustion established. Coal feed was established at 0930 hours. Pressure in the Gasifier was ramped to 140 PSIG and all was going quite well until a leak at the outboard seal of the LASH Feeder flooded the immediate area with Carbon Monoxide. Operators were instructed to depressurize the Gasifier and repairs will be done on the feeder. In addition, the fast-acting thermocouple in the Fines Combustor will be replaced. The Gasifier bed was once again fluidized and combustion occurred during the night of 4/1/99. Pressure was ramped to 200 PSIG, a new milestone. On the morning of 4/2/99, all was going well until a leak occurred in the outboard seal of the Desulfurizer Cyclone Fines Feeder and a valve in the Filter Fines Depressurization Bin failed. Gasifier was depressurized for repairs.

Post Start-Up Findings

The repairs to the Desulfurizer Cyclone Fines Feeder seal and the Filter Fines Depressurization Bin valve are in progress and, once completed, the Gasifier will be put through another start-up. To complete the repairs is expected to take two to three days. The next start-up will occur on about Wednesday, 4/7/99.

GASIFIER START-UP PROBLEM REPORT

Start-Up Number: 5 Date:3/31/99 Days Duration: 3

Problem Incurred	**Solution Rendered**
Nitrogen Product Compressor tripped on bad purity.	Compressor restarted
LASH feeder will not run.	I&C found that logic problems existed and corrected.
Recycle Gas Compressor will not load up.	The flow to the instrument purges is excessive. Throttled back to design.
Back pulse valve stuck open.	I&C redesigned piping.
Fines Combustor Tripping.	Slugged the transport line and over temperature. Operations settled the unit out.
Gasifier refueled at too high a level.	Operations allowed the bed to attrit.
High speed thermocouple in Fines Combustor burned out.	Replaced thermocouple.
Coal Feed Bin valve would not close.	Operators forced the valve closed with cheater.
HTF pressure low.	Back pressure regulator worked on by I&C.
Fines transport flow transmitter plugged.	New tubing installed.
Coal Feed Pressurization vent valve.	Operator cheated valve to make up limit.
Desulfurizer Cyclone Fines Feeder outboard seal blown packing.	Gasifier shutdown for repairs.

2.4.7 Start-Up Report #6

Start-Up Objectives

The objective of this start-up was to fire the Gasifier and raise pressure to rated (280 PSIG). Once at this point, LASH would be removed from the bottom and transferred to the Sulfator. Once inventoried, the Sulfator would be fired and subsequently the Desulferizer/Regenerator. The total run time at full load goal is 60 hours.

Results Of Start-Up

This start-up of the Gasifier consisted of three separate attempts. Attempt #1 consisted of getting the Gasifier to 100 PSIG for a short period. The Fines Combustor tripped due to change in the fines fuel quality. During the shut down, a rupture disc in the Filter Fines Feed Bin blew. The Gasifier was depressurized and repairs made. Another problem was found with a valve in the Coal Feed Package. It had to be replaced. In addition, the extra set of filters for the Filter Fines Depressurization Filter arrived on-site and were installed.

Gasifier start-up attempt #2 consisted of getting the unit to 100 PSIG once again and aborting the attempt due to the coal transport line being plugged. All attempts to unplug the line while the Gasifier was on line were futile. Gasifier was once again depressurized and the transport line dismantled and vacuumed out. In addition, the mid-level vibrating level probe in the Filter Fines Feed Bin was replaced.

Gasifier start-up attempt #3 consisted of getting the unit to 160 PSIG and then was aborted for good when a high level was achieved in the Hot Gas Filter. The fluffing nozzles in the Filter Fines Removal Package and vibrators are still not breaking the material loose so it will flow. Bridging in the bins is still hampering operation. The unit was secured and tagged out.

Post Start-Up Findings

The Desulfurizer Feed Cyclone Fines Feeder bound up and sheared a pin. Mechanics worked on the feeder, replaced the pin, and operations ran it. The feeder was obviously bound at the beginning of the operations but became much smoother as time went on.

The evaser nozzles in the fluffing lines for the Filter Fines Removal Package were removed. The plan is to put new evasers in and drill the orifices in the fluffing lines to a larger diameter to allow more gas through the nozzles. Also, the depressurization of the Filter Fines Depressurization Bin will be slowed by throttling the outlet valve to test if this will reduce the fines loading in the Depressurization Filter.

The shutdown period for the Gasifier will be one week and start-up will once again resume.

GASIFIER START-UP PROBLEM REPORT
Start-Up Number: 6   Date: 4/7 – 4/10/99
Days Duration: 3

Problem Incurred	Solution Rendered
BN502 & BN508 dome valves stuck in mid-travel position.	Forced dome valve for BN502 closed and stroked BN508 dome valve from PLC.
Fast responding thermocouple in H602 burned up.	Thermocouple was replaced. Process of finding better thermocouple for service is under way.
Material in BN503 and BN504 bridging.	Increased fluffing nozzle flow and vibrator time.
Fines Combustor tripped during operation from high temperature.	We speculate that the fines composition changed and the fuel content was too much.
Rupture discs (both 10') blew in BN507.	Problem was traced to logic change that was made. Changed time for fines valves to close to 10 seconds and the FD503 transport gas valve to 10 seconds.
PG503 dome valve UY0834A will not close completely.	Valve was dismantled and dome seal replaced. It had crease in it.
Coal transport line plugged and could not be freed up with unit on line.	Unit shut down, line dismantled, and vacuumed out.
FD401 feeder locked up and shear pin broke.	Feeder will be repaired during shutdown.
High-High level achieved in F501.	PG503 evaser nozzles are plugged. Engineering required.

2.4.8 Start-Up Report #7 – 10

Start-Up Objectives

The main goal of all four start-up attempts was to reach full load operation on the Gasifier (280 PSIG, 1000°F Syngas). Once at this point, LASH removal from the annulus of the Gasifier was to be the next major hurdle. Several modifications and repairs were made between subsequent start-up attempts and will be detailed later.

Results Of Start-Up

Start-Up #7 began Monday, July 12, 1999. Trouble with leaks at feeder seals and a loose wire on the Booster Air Compressor delayed the process for about 8 hours. The ability of the Grinder and Feeder to remove LASH from the bottom of the Gasifier was tested and proved functional. An additional delay was caused by the failure of the safety on the Gasifier steam ring. The valve is a 'one of a kind' and an additional delay of two days was incurred. Wednesday, July 14, start-up efforts resumed. A blown rupture disc on the LASH Feed Bin caused another shutdown of approximately 4 hours for repairs. Limestone feed to the Gasifier began and heat-up of the refractory and bed started. A dropped rod indicator falsely came in on the Recycle Gas Booster Compressor and was repaired. The Gasifier was loaded with 80 tons of limestone. This start-up will be done with a new procedure of heating up the Gasifier to 800°F with limestone bed before the Coke Breeze addition. During the heat-up process, the Desulfurizer Feed Cyclone Fines Feeder broke a shear pin and was repaired and the Recycle Gs Booster Compressor had a plugged transmitter line that was replaced. Coke Breeze addition went on until 70 tons were admitted to Gasifier bed. Coal feed was never initiated due to loss of the Gasifier on a Type II Shutdown on Hot Gas Filter Hi-Hi Level. During the trip, an air leak into the combustion air line caused a temperature hot spot in the piping. The unit was secured and tests the following week were conducted to insure the integrity of the line.

Start-Up #8 began Thursday, July 22. The new Filter Fines Diverter Line to the Waste Silo will be used to remove fines from the Filter fines Removal Package. This will eliminate the possibilities of the Fines Combustor causing any start-up problems. The Gasifier bed was lit off and 800° F refractory heat soak was performed. The proceeding start-up of the Gasifier was filled with problems with the Filter Fines Removal Package. A Hi-Hi level in the Filter Fines Collection Bin would trip the Filter Fines Screw Cooler and stop removal of fines from the Hot Gas Filter. This eventually caused operations to shutdown the Gasifier for re-evaluation.

Start-Up #9 occurred on September 2, 1999. The lag time between start up #8 and #9 was due to the addition of new filter cartridges in the Filter Fines Depressurization Filter vessel. The original filters in the vessel failed under operating conditions. The orifices in the pressurization and depressurization lines were changed to allow slightly faster pressurization and slower depressurization times. The fines loading of the filters is excessive and the smaller orifice is hoped to slow that down. The new filter cartridges proved to hold up so well that they 'blanked off' during depressurization cycles. As can be anticipated from this, an eventual Hi-Hi level in the Hot Gs Filter eventually took the Gasifier down. Logic changes in the Filter Fines Depressurization Filter sequence and addition of back pulse capabilities will be added before the next start-up attempt.

Start-Up #10 began on September 9, 1999. We took the Gasifier to full operating pressure (280 PSIG) and tested the Filter Fines Removal Package logic. It worked. A problem with the Recycle Gas Compressor occurred during past start-ups. A representative from the compressor manufacturer was called out to help us. The compressor surge curve had wrong numbers in the program. Once again, difficulties arose in removing the filter fines from the Hot Gas Filter. The Filter Fines Removal Package nuclear level detectors gave us false indications and the fines were bridging. An Instrument Technician was on hand constantly to force point in the PLC logic to get the bins to cycle. We were able to reach a new load on the Gasifier of 240 PSIG and 950°F. The Gasifier tripped when we lost the Booster Air Compressor on discharge temperature.

Post Start-Up Findings

The apparent difficulty of removing fines from the Filter Fines Removal Package was the cause for Gasifier shutdown during start-ups #7, #8 and #9. Start-up #10 shutdown was caused by a trip of the Booster Air Compressor, which was later identified as high discharge temperature. The Filter Fines Depressurization Filter vessels are grossly undersized and will require re-engineering. The replacement filters did not hold up to the conditions. Stronger elements need to be found. The Hot Gas Filter has broken candle filters in it. Cause seems to be a slug of material reaching the filter during the final depressurization of the Gasifier after shut down.

GASIFIER START-UP PROBLEM REPORT
Start-Up Number: 7 Date: 7/12/99
Days Duration: 6

Problem Incurred	Solution Rendered
Start-Up Heater flame scanner.	Instrument Technician repaired.
Several air leaks in Gasifier.	Mechanics repaired.
Booster Air Compressor trip on motor winding temperature.	Loose wire found.
Steam ring safety valve.	Sent off for repair.
Recycle Gas Compressor surging.	Plugged sensing line repaired.
Blown rupture disc in LASH Feed Bin.	Replaced by maintenance.
Dropped rod indicator in Recycle Gas Booster Compressor.	False indication.
Desulfurizer Feed Cyclone Fines Feeder shear pin.	Replaced by maintenance.
Hot Gas Filter back pulse skid.	False valve indications solved.
Assist ring gas flow	Instrument technician repaired.

transmitter failed.	
LASH Feeder bound up.	Emptied out the material packed in feeder.
Filter Fines Removal Package. Fines bridging. Slow depressurization time.	Logic changes.
Fire in combustion air line.	Start Up valve left open. Small air leak ensued.

GASIFIER START-UP PROBLEM REPORT
Start-Up Number: 8 Date: 7/22/99
Days Duration: 3

Problem Incurred	**Solution Rendered**
Fines Combustor will not light off.	Scanner repaired.
Recycle Gas Compressor surge trips.	Hand jacked open suction valve.
Gasifier air leaks.	Maintenance repaired.
LASH Feeder bound up.	Reversed from VSD to free it up.
Desulfurizer Feed Cyclone Fine Feeder packing leak.	Maintenance repaired.
Fines bridging. Filter Fines Depressurization Bin fail to depressurize.	Logic Changes. Filter elements.

GASIFIER START-UP PROBLEM REPORT
Start-Up Number: 9 Date: 9/2/99
Days Duration: 1

Problem Incurred	**Solution Rendered**
Emergency Coal Feeder wouldn't run.	Electrician adjusted speed switch.
Fines bridging. Filter Fines Depressurization Bin failure to depressurize.	PLC constant forcing of points by instrument technician.

GASIFIER START-UP PROBLEM REPORT
Start-Up Number: 10   Date: 9/9/99
Days Duration: 2

Problem Incurred	Solution Rendered
Fines Combustor would not light off.	Scanner. Air flow/fuel flow ratio.
Nuclear level detectors. Filter Fines Collection Bin bridging.	PLC. Instrument technician constantly forcing points to cycle bins.
Booster Air Compressor trip.	Later determined to be high discharge temperature.
Emission of fines from Flare.	Broken candles in Hot Gas Filter. Not sure of the cause.

2.4.9 Start-Up Report #11 - 17

Start-Up Objectives

Major modifications have been made to the Filter Fines Removal Package. In past runs of the Gasifier, we have been unable to keep up with the fines production, which caused eventual shutdown of the unit due to an extreme high level in the Hot Gas Filter. The objective of the ensuing Gasifier runs is to prove that the modifications, along with changes in logic, will allow the Filter Fines Removal Package to remove fines in a consistent manner and keep up with production.

Another objective is to prove (or disprove) the operation of the Gasifier annulus. Can we remove LASH? Can we cool the LASH? These questions have still been unanswered.

Results Of Start-Up

The start-up of the unit will be categorized into several attempts. To begin the process, we determined that a test to try and remove hot limestone from the annulus, before adding fuel, would be beneficial. If we could cool the limestone, and operators had time to play with flows and watch trends, this would give us some indication of the ability of the annulus to perform as designed. The tests of the annulus proved that the material cannot be cooled at a sufficient rate to allow continuous removal. The modifications made to the Filter Fines Removal Package proved to lengthen the runs at the onset and, with modifications to logic, proved better with each successive run.

Listed below are the numbered starts of the Gasifier and reason for failure:

#11 – Failed seals on LASH Feeder.

#12 – Limestone Removal Test Completed and Gasifier heat soak begun.

#13 – Gasifier Type II Shutdown because of high level in the Hot Gas Filter.

#14 – Ran out of fuel in the Coal Feed Package and had to slump the bed. In addition, nitrogen tank level reached a low limit.

#15 – Gasifier Type II Shutdown because of high level in the Hot Gas Filter. We experienced a flare "visible emission" afterwards. The filter was borescope to try and locate broken candles, but none were found.

#16– Gasifier Type II Shutdown due to high level in the Hot Gas Filter. In addition, nitrogen tank level reached a low limit.

#17– Gasifier Type II Shutdown due to high level in the Hot Gas Filter. The Filter Fines Removal Package seemed to keep up with the fines production for the first time. The high level achieved in the filter was later determined bogus.

Post Start-Up Findings

The failed seals on the LASH Feeder were caused by previous machining being done to the unit. Mechanics built end plates for the two sides of the feeder to enable the packing to have more surface to rub. Each Gasifier Type II Shutdown due to high level in the Hot Gs Filter was followed by a subsequent change in logic to speed up the cycling of the lock hoppers. Unfortunately, the shutdowns cause the Flare nitrogen purge system to activate and our usage increased dramatically while we try to catch up. The slumped bed caused by loss of fuel in Coal Feed Package was caused by valve that was defective and would not open/shut in a timely manner. The valve was replaced. All other plaguing problems are listed in the Start-Up Problem Reports.

GASIFIER START-UP PROBLEM REPORT
Start-Up Number: 11 Date: 1/28/2000
Days Duration: 2

Problem Incurred	Solution Rendered
Transport Gas For LASH Feeder	The vent valve on LASH Collection Bin was forced open.
#1 Vent Valve For Coal Feed Pressurization Bin	Valve Was Looked At And Operation Deemed Accurate.
Recycle Gs Compressor Discharge Pressure	Compressor unloaded for no reason. The controller had a missing loop in it and was restored.
Coal Feeder Binds Up While Moving Straight Limestone	Feeder needed to be reversed several times to free it up.
Limestone Coming Out Of Silo In Large Clumps	Raised the feeder spreader bar in order to allow clumps to flow on belt.
Recycle Gas Compressor control.	C Technician tried to tune controller, but no luck.
Hot Gas Filter Hi-Level Nuclear Alarm Switch	Came in several times during limestone fluidizing. Filter was blasted with manual nozzles.
LASH Feeder Transport Line Plugging	Ran the Grinder and Feeder at minimum speed and throttled the Gasifier LASH outlet valve.
LASH Feeder Seals	They blew out and limestone was escaping. Gasifier shut down for repairs.

GASIFIER START-UP PROBLEM REPORT
Start-Up Number: 12 Date: 2/4/2000
Days Duration: 2

Problem Incurred	Solution Rendered
Filter Fines Feeder Won't Run Without Forcing Points In The PLC While Diverting To Waste Silo.	This will be incorporated with the addition of the Fines Surge Bin.
Lost LASH Feeder and Grinder On Hi-Temp While Withdrawing hot limestone	None.

LASH Removal Package Cycling	PLC logic worked with.
Recycle Gas Booster Compressor Tripped Twice	Operator error (unopened suction valve, trying to load too quickly).
Level Of Limestone In Coal Feed Bin Stopped Registering.	Points forced in PLC.
Recycle Gas Compressor Discharge Pressure Erratic.	Hand jacked open the suction regulator valve.
Heating Limestone Bed To 800°F	Inlet temperature to Hot Gas Filter exceeded 400°F, which could cause ignition in the filter.
Rupture Discs Blown On Coal Feed Surge Bin.	The PLC opened the valve above the Coal Pressurization Bin with 25 PSIG pressure still in the bin. I&C technician checked logic.
Recycle Gas Booster Compressor Tripping Occasionally	Low second stage suction pressure. No solution.
Filter Fines Depressurization Bin Valve Would Not Actuate	Limit Switch Mounted Incorrectly. Two Pennies Were Glued To Switch.
While Withdrawing LASH, Feeder and Grinder On Hi Inlet Temp	On shift process engineer felt that the pressure on the Gasifier at the time (140 PSIG) was too low and LASH Feeder RPM (4) too fast.
HTF Low Flow Alarms	Back Pressure Regulator Not Working Correctly.
Filter Fines Transport Line Plugged	Blown free with air.
Plugged Nozzles In Upper Steam Ring	Operators worked at unplugging them individually with little success.
LASH Feeder Runs Too Fast	Installed new sprockets on the drive and feeder to slow it down.
LASH Feeder Transport Line Plugged	Mechanics broke line and cleaned.

GASIFIER START-UP PROBLEM REPORT
Start-Up Number:13 Date: 02/05/2000
Days Duration: 1

Problem Incurred	Solution Rendered
Included In Report For Start-Up #12	

GASIFIER START-UP PROBLEM REPORT
Start-Up Number: 14 Date: 2/7/2000
Days Duration: 1

Problem Incurred	Solution Rendered
Report For Start-Up #12	

GASIFIER START-UP PROBLEM REPORT
Start-Up Number: 15 Date: 2/12/2000
Days Duration: 1

Problem Incurred	Solution Rendered
Filter Fines Screw Cooler Outboard Seal Blowing	None at this time.
LASH Bridged Above Grinder	All efforts to break it loose failed.
Lost Gasifier On Type II Trip	Fines package would not keep up with the production. Logic changes were made in the PLC.
Recycle Gas Booster compressor Still Not Running Without Intermittent Trips On Low Suction Pressure	No solution is available at this time.
Syngas Leak At Filter Fines Screw Cooler	Small leak coming from beneath insulation. It will be checked during next down period.
Syngas Leak At Bottom Of Gasifier	Operators portable monitors went off while in the area. It will be repaired next down period.
HTF Sytem Flow And Pressure	Mechanical Problem With Pumps.
Fines Transport Gas Transmitter Not Registering Flow	I&C technician checked sensing lines and they are OK. Will be repaired next down period.
Steam Nozzle #15 Has Steam Leak	Will be repaired next down period.
17 Out Of 24 Nozzles In	None at this time.

Upper Steam Ring Are Plugged	

GASIFIER START-UP PROBLEM REPORT
Start-Up Number: 16 Date:2/13/2000
Days Duration: 1

Problem Incurred	**Solution Rendered**
Apparent Obstruction In Air Feed Tube	Operations tried to blow out the tube with no pressure in the Gasifier. Emission from Flare occurred.
Flare Emission	Deemed to be smoke not fines. Inspected the internals of the Hot Gas Filter with borescope and no broken candles were found.
Nitrogen Plant Tripped	The air compressor discharge pressure and flow transmitters failed. I&C repaired. Operations restarted plant.
Gasifier Down Time Repairs	Tighten packing on LASH Feeder and Grinder. Tighten bolts on Filter Fines Screw Cooler. Remove flange from Desulfurizer Feed Cyclone Fines Feeder and clean line.
Nitrogen Plant Back Up Pump Not Putting Out Pressure	Vapor locked.
Green Paint At Gasifier Nozzle Turned White	Area was “shot” with heat gun and all is well.
Recycle Gas Booster Compressor Still Trips Intermittently	Suction pressure?
Recycle Gas Compressor Discharge Pressure Erratic	More controller tuning?
Gasifier Type II Trip	Hi-Hi Level in Hot Gas Filter. Gasifier shut down for repairs and refilling of nitrogen tank.
Gasifier Shutdown Repairs	Leaky seals. Feeder discharge plugged. Coal transport line came off of spring can. Check suction of Recycle Gas Compressor for fines. Repaint discolored area of Gasifier. Plus more.

GASIFIER START UP PROBLEM REPORT
Start Up Number: 17 Date: 2/26/2000
Days Duration: 1

Problem Incurred	Solution Rendered
HTF Leak At The End Of Filter Fines Screw Cooler	The leak was contained during the Gasifier run and repaired the next day.
Filter Fines Screw Cooler Tripped Several Times On HTF Flow	I&C Technicians checked the back pressure regulator for proper operation.
Coal Feeder Tripped On Mystery	Suspect that it bound up and went out on overload. Feeder restarted the first attempt.

2.4.10 Start-Up Report #18

Start-Up Objectives

This start-up of the Gasifier was intended to test the modifications made to the annulus section. Up until now, we have been unable to cool the LASH sufficiently for withdrawal. In addition, new refractory in the Gasifier vessel coupled with a heat-up schedule that would most likely prevent any thermal damage would be attempted. Prevention of the refractory spalling is of utmost importance since we have never been able to remove LASH from the bottom of the Gasifier.

Results of Start-Up

Operations began to heat-up the Gasifier on Monday morning 8/7/2000. Once the unit began to heat up, a 44.5 hour heat-up schedule had been devised by Gasification Engineering for the new refractory. On the evening of Thursday 8/10/200, the heat-up of the Gasifier was completed. Some testing of equipment remained to be done so the temperature of the reactor was held for another eight hours to wait until day shift technicians were on-site to help with the testing.

The heat-up of the Gasifier was accomplished at 75 PSIG. In order to test equipment, the pressure was raised to 200 PSIG to simulate the load we intended to run the unit at once we fired it. The equipment testing was completed and the pressure was being lowered on the unit to allow for some maintenance on the clinker grinder. Smoke started emanating from the Flare. The Control Room Operator checked the temperatures inside of the Hot Gas Filter and it was obvious that it was on fire. The start-up was aborted, pressure taken from the Gasifier, and the Hot Gas Filter flooded with nitrogen.

Post Start-Up Findings

Once it was cool enough, the bottom access door to the Hot Gas Filter was opened up and broken candle filters were lying in the cone. It was then that we decided to let the vessel cool over the weekend and open up the rest of it for inspection on the following Monday. It was then that we found the damage to the filter.

GASIFIER START-UP PROBLEM REPORT
Start-Up Number: 18 Date: 8/10/200
Days Duration: 5

Problem Incurred	Solution Rendered
1. Smoke began coming out of Flare Stack. Gasifier Team Leader asked Control Room Operator to check the temperatures in the Hot Gas Filter. The temperatures had taken off for no apparent reason. We had been in a heat soak for several days. The Gasifier had been up to 800°F freeboard temperature three times. The inlet temperature to F-501 was holding at approximately 400°F. We were lowering pressure from 200 PSIG to 75 PSIG at 2 PSIG/Minute.	Control Room Operator removed air from Gasifier. The filter smoldered for a few minutes and operator was able to flood with nitrogen. It took some time for the outlet temperature to begin to drop. Eventually, nitrogen was introduced to the Gasifier and the entire Syngas stream was inerted.

From data gathered from the temperature excursion, it was determined that there had been some volatile fuel “rat holed” in the Desulferizer Cyclone dip leg and it became fluidized when the decreasing pressure ramp was started. It ignited and carried over to the Hot Gas Filter. By the time that air could be removed from the system, The temperature of the Hot Gas Filter outlet reached 2000°F.

Inspection of the filter internals occurred on 8/14/2000. Several broken filter elements are laying in the bottom of the vessel. The upper plenums of the filter have fire damage to the tube sheets.

Figure 20 – Damage to Hot Gas Filter

3.0 Critical Component Failure – Pinon Pine Combined Cycle

The Pinon Pine Combined Cycle consists of a GE 6FA combustion turbine, a two pressure ATS heat recovery steam generator (HRSG), and a 46 MW GE steam turbine. The combined cycle unit was put into commercial operation in October 1996. Since being placed into commercial operation, the unit experienced three critical component failures that resulted in extended outages. This section presents the details of the failures and is organized in the following sections: Failure Identification, Description of Failure, Disposition of Failed Item, and Action Taken.

3.1 HRSG High Pressure Drum Cyclone Failure

3.1.1 Failure Identification

In August 1997, the Pinon Pine HRSG experienced a tube leak that required the unit to be taken off-line. This provided an opportunity for Sierra to perform a routine inspection of the HP and LP drums on the unit. The subsequent inspection of the HP drum revealed extensive damage to the stem separation cyclones. Base on the results of the inspection, and after a review of plant operating data, it was apparent that the damage occurred in the commissioning phases of start-up and went undetected for several months.

3.1.2 Description of Failure

The steam separation unit in the HP drum of the Pinon Pine HRSG consists of a series of cyclone separators attached to a single inlet plenum. The August 1997 inspection of the unit revealed that the front wall of the inlet plenum had separated from the plenum box. This resulted in saturated steam by-passing the separation cyclones and dumping directly into the drum. The HRSG manufacturer was contacted to address warranty issues related to the failure and to assist with the root cause analysis. The results of the root cause analysis indicated that the failure was due to quality control during fabrication. The vendor was very responsive and upheld their warranty obligations.

3.1.3 Disposition of Failed Item

All components involved in the failure were returned to service.

3.1.4 Action taken

The vendor and SPPCo. developed a repair procedure for the damaged inlet plenum. The procedure required that new backing plates be fabricated for each cyclone separator and that the failed front plate be reattached to the plenum. Repairs were completed in approximately 4 days, and the unit was returned to service.

3.2 Combustion Turbine Load Coupling Failure

3.2.1 Failure Identification

On March 27, 1998, the Pinon Pine combustion turbine experienced a step-change in vibration on the #1 bearing. GE was notified of the occurrence and Bently Nevada was contacted for diagnostic support. Review of data collected using plant instrumentation indicated that vibration increased in the #1 bearing from 2 mils to approximately 4 mils over a 20 minute time period. Other bearings on the machine showed a disturbance at the same time, however all but the #1 bearing returned to normal levels. Further examination of the data showed that, with the exception of the #1 bearing, all of the bearings experienced a permanent shift in phase.

The vibration information obtained by SPPCo. was forwarded to GE vibration specialists. At this time, the unit was still under warranty, and GE recommended no corrective action.

Over the next several weeks, the vibration in the #1 bearing continued to increase. SPPCo. continued to collect vibration data and forwarded the information to GE. On April 30, the vibration had increased to 6.1 mils and GE agreed to send field engineers to the site to perform an inspection. The unit was taken off-line, and a cursory inspection by GE showed no apparent damage. On May 6, GE recommended that the unit be restarted so that more data could be collected. When the unit was restarted, vibration levels reached over 7 mils, and SPPCo. elected to shut the unit down. On May 13, GE agreed to send a field crew to the site to perform a more rigorous inspection.

3.2.2 Description of Failure

During the subsequent inspection, the source of the increased vibration was discovered. On 5/14/98, the load coupling between the turbine and the gear box was removed from the unit for inspection. The coupling had massive cracking in the diaphragm on the turbine end of the coupling. Further examination indicated that the coupling was very near complete failure. The root cause of the failure was 'misapplication'. The original coupling was not able to withstand the duty.

3.2.3 Disposition of Failed Item

The failed coupling was returned to GE for root cause examination.

3.2.4 Action taken

GE supplied a new 'heavy-duty' coupling. The coupling was installed on 5/21/98, and the unit was returned to service.

3.3 Combustion Turbine Bucket Failure

3.3.1 Failure Identification

During the April 1998 investigation of the load coupling failure (see previous section), a borescope inspection was performed on the unit. The borescope inspection revealed evidence of 'shroud lift' on the 2^{nd} stage buckets. A subsequent outage was scheduled for 10/23/98 to perform another borescope inspection on the unit to assess the degree of shroud lift and determine if any related damage had resulted.

The scope of the 10/23/98 outage was initially limited to borescopic inspection of the 2^{nd} stage, DCS / MarkV Y2K testing, and outage work orders (balance of plant). During the borescope inspection, extensive damage was found on the 2^{nd} stage buckets. The outage was then expanded to include replacement of the buckets and inspection of the remaining hot gas path components.

3.3.2 Description of Failure

Figure 21 shows the damage to the 2^{nd} stage buckets. The shrouds on the 2^{nd} stage buckets were found to have distorted in the radial direction toward the turbine shell. The distorted sections of shroud made contact with the honeycomb seal blocks in the shell. Both the shrouds and honeycomb seals received extensive damage. GE determined that the failure was related to the design of the buckets.

3.3.3 Disposition of Failed Item

The failed buckets were returned to GE for root cause examination.

3.3.4 Action taken

Machine was put back into service with new buckets.

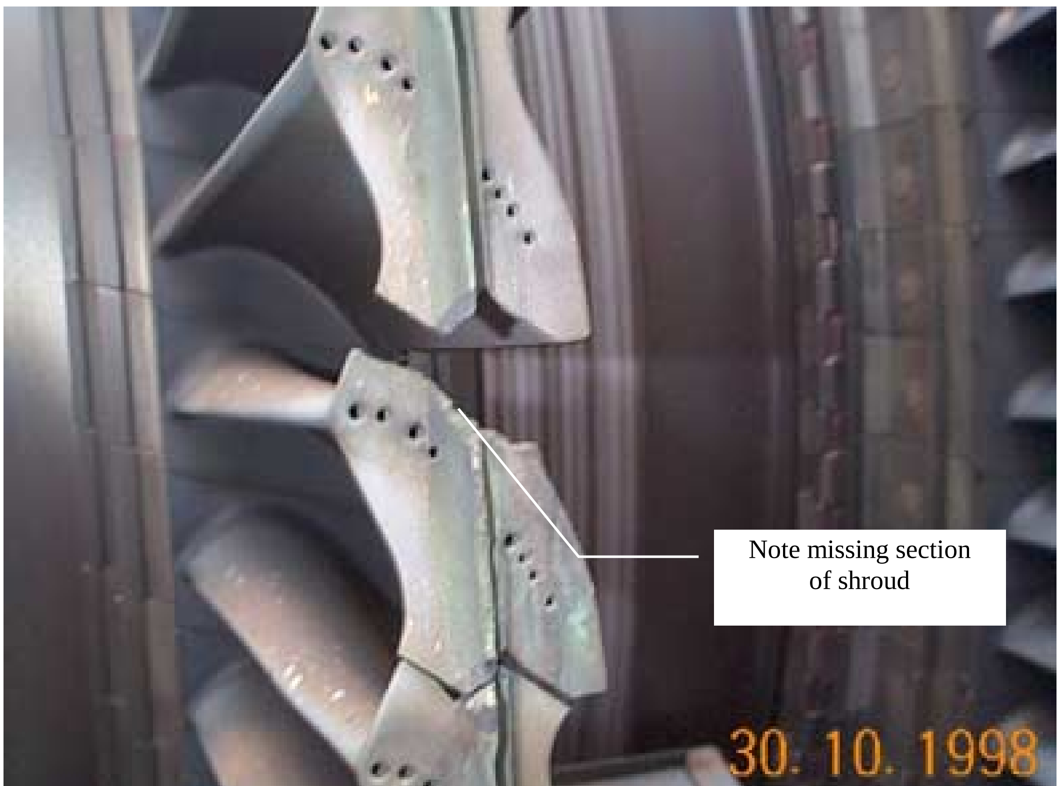


Figure 21 - 2nd Stage Shroud Damage

3.0 (Cont.) Critical component failure – Pinon Pine Gasifier Island

The Pinon Pine Gasifier Island consists of a KRW (Kellogg, Rust, Westinghouse) coal Gasifier with associated equipment. During the commissioning and start-up of the Gasifier Island several component failures resulted. This section presents the details of the failures and is organized in the following sections: Failure Identification, Description of Failure, Disposition of Failed Item, and Action Taken.

3.4 Combustion Air Line Failure

3.4.1 Failure Identification

On 4/18/98, a failure of the Gasifier combustion air line occurred. The Gasifier was in the process of a start-up, under pressure, when a hole blew out in the line. Danger to personnel in the area was apparent.

3.4.2 Description of Failure

While lifting the Gasifier bed and attempting to establish operation, a hole blew out in the combustion air line. This line supplies extraction air to the Gasifier jet for control of the combustion process and to keep the bed fluidized. Operators were forced to trip the unit and depressurize quickly in order to avoid safety concerns and possible harm to outside employees. The fact that no one was in the area at the time helped.

After inspection of the section of the line that failed, it was determined that fuel had congregated in the area during a previous bed slump. When start-up air was commenced, the fuel reached ignition temperature and burned out the piping in the area of the failure. The entire spool piece that contained the failure was removed and sent for analysis.

3.4.3 Disposition of Failed Item

An entire new spool piece for the air line was fabricated and installed.

3.4.3 Action taken

Procedures for the Gasifier were altered to try and avoid having unspent fuel in the combustion air line during initial start of flow. If the piping is “cleaned out” prior to having the air flow started, possible failure of the component in the future will not occur. Additionally, nitrogen purge for the line had an orifice in it that was resized to avoid any chance of abrasion to the section of the pipe that failed. The melted portion shown below in Figure 22 was caused by localized fire inside the Gasifier annulus.

Figure 22 – Damaged Combustion Air Feed Tube

3.5 Gasifier Air/Feed Tube Failure

3.5.1 Failure Identification

The operation of the Gasifier depends on the ability of the Coal/Air Feed Tube to supply fuel and air to the fluidized bed. After Start Up Number 6 had been completed, inspection of the Coal/Air Feed Tube assembly showed that a portion of it has burned away.

3.5.2 Description of Failure

We were unable to empty the Gasifier through the bottom LASH removal equipment and were forced to have a vacuum truck come out and remove the Gasifier bed from the top down. Once we reached the throat area where the Coal/Feed tube protrudes, damage to the assembly was apparent. Upon removal of the annulus section of the Gasifier to allow the Air/Feed Tube to be taken out, a hole in the outer air tube was noticed. Further investigation shows that an orifice plate that goes into an instrument purge line had been left out during the last disassembly of the annulus. This eroded a hole in the air tube and subsequent mixing of the combustion air and fuel occurred. Figure 23 shows the burnt tube and subsequent plugging that occurred.

3.5.3 Disposition of Failed Item

The failed Coal/Air Feed tube assembly was sent to a fabrication shop for repair.

3.5.4 Action taken

In the future, after any work is performed on the annulus area of the Gasifier, complete inspections will be performed to prevent the missing of parts.

Figure 23 – Gasifier Coal Feed Tube

3.6 Gasifier Refractory

3.6.1 Failure Identification

Initial designed refractory for the Gasifier spalled off the walls and nozzles.

3.6.2 Description of Failure

The Gasifier refractory was designed to be a wear and thermal barrier against the abrasive environment and the heat of the Gasifier bed. Two layers of refractory, both six inches thick, were put on the walls and grid area to provide this protection. The thermal cycling of the Gasifier caused the outer wear layer to peel off and fall. This would plug up the bottom of the Gasifier and removal of material through the bottom LASH equipment became impossible. See figure 24.

3.6.3 Disposition of Failed Item

The refractory in the grid area and 18 feet up the walls was removed, old anchors ground out, new anchors welded in, and one layer of thermal refractory installed.

3.6.4 Action taken

M. W. Kellogg process engineers and personnel from Gasification Engineering Corporation were enlisted to help develop a slower heat up for the Gasifier once the bed is ignited. This has proven to be very difficult to control in the past.

Figure 24 – Gasifier Refractory

3.7 Fines Combustor Expansion Joint

3.7.1 Failure Identification

The Fines Combustor has an expansion joint between the incinerator and the Heat Recovery Steam Generator. The joint failed during Fines Combustor operation.

3.7.2 Description of Failure

The expansion joint is designed to allow two different structures to go through thermal cycles and keep the process sealed up to the atmosphere. It is made of Inconel wire with Kaowool stuffed in it. During operation of the Fines Combustor, unburned fuel accumulated in the wire mesh, caught on fire, and burned out the joint. Reference figure 25.

3.7.3 Disposition of Failed Item

The old expansion joint was removed and a new one replaced, In addition, an Inconel sleeve was installed to prevent the accumulation of fines in the new joint. New temperature indicators were designed and installed for the discharge temperature control.

3.7.4 Action taken

The Fines Combustor control scheme was gone through, new temperature indicators installed, and an oxygen analyzer placed in the flue gas section to prevent any future overheating in the unit.

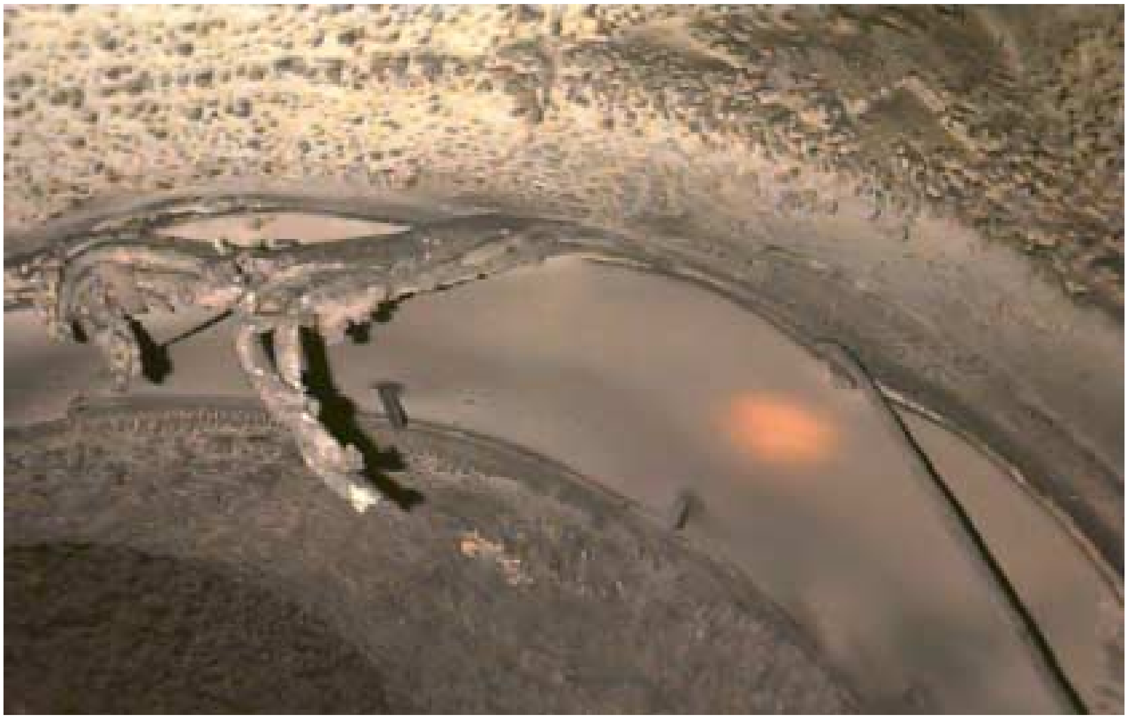


Figure 25 - Fines Combustor Expansion Joint

3.8 Filter Fines Removal Package Depressurization Filter Capacity

3.8.1 Failure Identification

The purpose of the Filter Fines Removal Package is to remove fines from the Hot Gas Filter and feed the collected fines stock to the Fines Combustor . The system consists of 3 lock hoppers (Filter Fines Collection Bin, Filter Fines Depressurization Bin, And Filter Fines Feed Bin all separated by valves), a Depressurization Filter, and a Filter Fines Screw Feeder. A brief description of the original design / operation is included below for clarity.

When the Gasifier is in operation, fines accumulate on the filter elements in the Hot Gas Filter. The filter is cleaned by back pulsing recycle gas or nitrogen through the elements. The back pulsing sequence is initiated by either a timer or pressure differential across the filter. The fines that are released from the filter elements as a result of the back pulsing accumulate in the bottom cone section of the filter. A Filter Fines Screw Cooler located at the bottom of the HOT Gas Filter is used to transfer fines to the Filter Fines Removal Package. The three bin set up is then used to reduce the pressure of the fines (from system pressure to atmospheric) and feed the fines into the transport line feeding the Fines Combustor. The original (as-designed) operating sequence for the Filter Fines Removal Package is summarized below:

1) Filter Fines Collection Bin remains at system pressure and receives a continuous flow of fines from the Filter Fines Screw Cooler.

2) The valve between the Filter Fines Collection Bin and the Filter Fines Depressurization Bin is open, allowing fines to pass through. The valve between the Filter Fines Depressurization Bin and Filter Fines Feed Bin is closed.

3) When a high level is detected in the Filter Fines Depressurization Bin, the valve is shut, isolating the bin at system pressure.

4) The Filter Fines Depressurization Bin is then depressurized by venting the gas trapped through the Depressurization Filter.

5) When the pressure in the Filter Fines Depressurization Bin is within 4 psi of the pressure in the Filter Fines Feed Bin, an equalization line between the two bins is opened to ensure that the bins are at the same pressure.

6) The valve between the bins is then opened, allowing The Filter Fines Feed Bin to receive depressurized fines from the Filter Fines Depressurization Bin.

7) The Filter Fines Depressurization Bin is then isolated by shutting the valve.

8) The Filter Fines Depressurization Bin is then pressurized to system pressure by back flowing recycle gas through the Depressurization Filter.

9) The valve between the Filter Fines Collection Bin and the Filter Fines Depressurization Bin is then opened to begin another cycle.

The original Depressurization Filter system consisted of a single (12 inch diameter) canister housing 8 sintered metal filter elements (each 1 meter long). In Gasifier test runs prior to 12/98, limitations of the filter system were responsible numerous Gasifier trips. The limitations, primarily filtration capacity and filter performance, were identified by equipment inspection and through review of operating data. Problems typically manifested as an inability to depressurize the Filter Fines Depressurization Bin.

3.8.2 Description of Failure

The primary mode of failure was related to the filter elements ‘blinding-off’, which made it impossible to depressurize the Filter Fines Depressurization Bin. In some cases, the elements would collapse as a result of the increased pressure differential due to blinding. This problem went undetected during several Gasifier runs because when the elements would collapse, the system would appear to operate as designed.

The original design basis for the system did not adequately address the fines loading when depressurizing the Filter Fines Depressurization Bin. In virtually every Gasifier run prior to 12/98, the filter system was over-loaded due to insufficient filter area and an inability to rigorously clean the elements between cycles. The inability to depressurize limited the rate at which material could be removed from the Hot Gas Filter and resulted in numerous Gasifier trips and ultimately ceramic candle damage.

3.8.3 Disposition of Failed Item

All failed filter elements were damaged beyond salvage and were scrapped.

3.8.4 Action taken

Modifications to the Filter Fines Removal Package were completed in two phases. The first phase, completed in mid-1999, involved adding a second Depressurization Filter canister, doubling the original filtration capacity of the system. In addition, high-pressure back pulse capability was added to the system and the filter elements were upgraded to withstand 300 psi differential pressure. Subsequent test runs of the Gasifier showed that the increase in capacity was still insufficient.

In the second phase, material testing was performed on fines to develop a ‘true’ basis for a new design. Based on the results of the testing, it was determined that the new system would have to have 10 times the capacity of the original (single canister) design. In late 1999 design of the new system utilizing a total of 10 Depressurization Filter canisters began and in 2/2000 the completed system was tested. The system performed within the cycle timing constraint of 6 minutes per cycle, and demonstrated a removal capacity near design (5600 LB/hr.).

Figure 26 shows the P&ID for the final design.

3.9 Filter Fines Removal Package Bin Level Detection

3.9.1 Failure Identification

The original design of the Filter Fines Removal Package included capacitance-type level detection probes. These probes proved to be unreliable for control of the package cycling and resulted in erratic or nonexistent fines removal rates.

3.9.2 Description of Failure

The original capacitance probes gave false level indications in the bins. In some cases, this would fail to initiate a depressurization cycle, resulting in fines over-filling the bins and backing-up in the Hot Gas Filter. In other cases, a cycle would be initiated with little or no material present. These conclusions were based on observations of material passed to the Filter Fines Feed Bin (the atmospheric pressure bin). The root cause was misapplication of the probes.

3.9.3 Disposition of Failed Item

The original probes were removed from service.

3.9.4 Action taken

The capacitance probes were replaced in mid-1998 with nuclear level detection devices and vibration-based level detection probes. The new probes have demonstrated high reliability and accuracy. As a result, the bin cycling problems related to level detection have been resolved.

3.10 Filter Fines Removal Package Fluffing Nozzles

3.10.1 Failure Identification

The original design of the Filter Fines Removal Package included 4 Evaser nozzles mounted in the cone section of the

Filter Fines Collection and Depressurization Bins. The purpose of the nozzles was to mitigate material bridging problems and improve material transfer between the bins. The Evaser nozzles did not provide sufficient fluidization to prevent material bridging in the bins.

3.10.2 Description of Failure

The Filter Fines Removal Package was chronically plagued by material bridging problems, which seriously limited the performance of the fine removal package. The material bridging was noted when the valves on the Filter Fines Depressurization Bin would open and a corresponding change in level would not result. This indicated that material was not transferring between the bins and was most likely bridging in the cone sections of the bins. Several attempts were made to modify the existing nozzle system, specifically, flow rates to the existing Evaser systems were modified and the Evaser heads were changed out. None of the modifications to the existing system produced acceptable results.

3.10.3 Disposition of Failed Item

The existing Evaser system was removed from service.

3.10.4 Action taken

The Evaser system was replaced with Skimmer valves on the Filter Fines Collection and Depressurization Bins. Skimmer valves are designed to specifically remedy bridging problems in bulk material handling and have been proven effective in this type of application. The Skimmer valves direct a burst of high pressure gas against the wall of the bin, breaking up the foot of the material bridge. The Skimmer valve system was tested during Gasifier runs in early 2000 and has resolved the bridging problems. Figure 26 shows the Skimmer valve additions to the Filter Fines Removal Package.

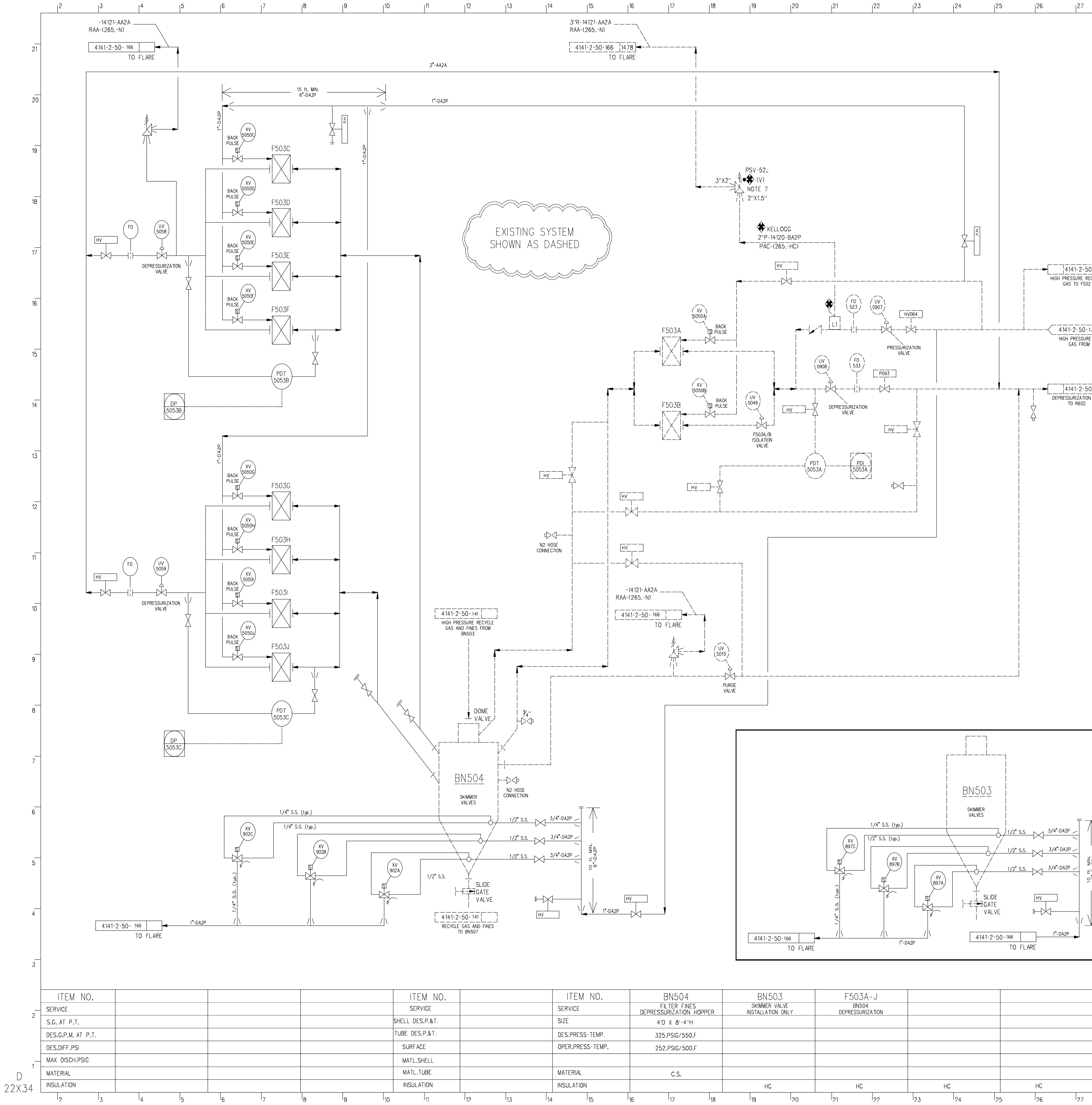


Figure 26 – Modifications Made To Filter Fines Removal Package

3.11 Recycle Gas Compressor Eroded Impeller

3.11.1 Failure Identification

During the candle filter failure of mid 1997, Filter Fines were allowed to pass through the Recycle Gas Compressor. The failsafe devices supplied for the Hot Gas Filter failed to function correctly. This eroded the compressor impeller. See figure 27.

3.11.2 Description of Failure

Broken candle filters inside of the Hot Gas Filter were supposed to be "blanked off" by a failsafe device. This would allow the continued operation of the Gasifier with failed elements. During the run of the Gasifier, some visible emissions could be seen coming from the Flare stack. It was not considered at the time that there could be enough fines leaking through the filter to cause damage to downstream equipment.

3.11.3 Disposition of Failed Item

During the subsequent shutdown of the Gasifier, the inlet piping to the Recycle Gas Compressor was removed so that the compressor could be inspected. It was at this time that the eroded impeller was noticed. In addition, a fine dusting of material was found to be coating the inside of the recycle gas piping. An inlet strainer to the compressor was provided by the manufacturer, however it is designed to be more of a trash collector than a filter.

3.11.4 Action taken

A new impeller and gear box for the Recycle Gas Compressor were installed. All of the recycle gas piping that leads to the suction of the machine was cleaned. The Syngas line to the control valves for the turbine was cleaned as well. All future runs of the Gasifier will be aborted upon any indication of fines leak through in the Hot Gas Filter. Westinghouse is in the process of testing new designs for filter failsafes.

Figure 27 – Recycle Gas Compressor Impeller

3.12 Sulfator Solids Screw Cooler

3.12.1 Failure Identification

The Sulfator Solids Screw Cooler developed an internal leak.

3.12.2 Description of Failure

During a de-inventory process of the Sulfator, the Solids Screw Cooler bound up and would not turn. The end cap was removed from the screw and set up limestone material was found. Evidence of a leak was apparent.

3.12.3 Disposition of Failed Item

The screw was removed from the case and the spot of the leak identified. This took considerable effort. A crane had to be brought in and the close proximity of other equipment made the removal of the screw extremely difficult. The leak was ground out and new metal welded in place. A spare screw for the cooler was installed. It has a diameter that is 2 inches less than the original. The leak was caused by a rub between the screw and the casing.

3.12.4 Action taken

The leak was repaired, new screw was installed, tolerances checked, and the unit was put back into service. It has not been run with any substantial amount of material in it since the failure. Figure 28 shows reassembled unit.

Figure 28 – Sulfator Solids Screw Cooler

3.13 Heat Recovery Steam Generator

3.13.1 Failure Identification

After several firings of the Fines Combustor, the HRSG (figure 29) developed tube leaks in the boiler and there were several flue gas leaks in the structure.

3.13.2 Description of Failure

During firing of the Fines Combustor, hot flue gas is diverted through the HRSG to generate steam. It is a small double drum boiler. The outer structure for the boiler developed flue gas leaks that were obvious. The drum developed tube leaks which were noticed by water dripping from the hoppers beneath the unit.

3.13.3 Disposition of Failed Item

The HRSG was removed from service and the vendor contacted to come out and repair the failures. The tube leaks occurred due to the thermal expansion of the boiler pulling several tubes from the upper drum. All of the tubes were rolled and welded, including ones that did not fail.

The lagging and insulation was removed from the exterior of the boiler structure and cracks were sealed and welded.

3.13.4 Action taken

Once repairs were completed, the HRSG was returned to service. A heat-up schedule of 100°F per hour was established on the drums. All hoppers were cleaned out and a vendor was brought in to design and supply a removal system for the hoppers. There was no means of emptying the debris and ash from the bottom of the HRSG supplied originally.

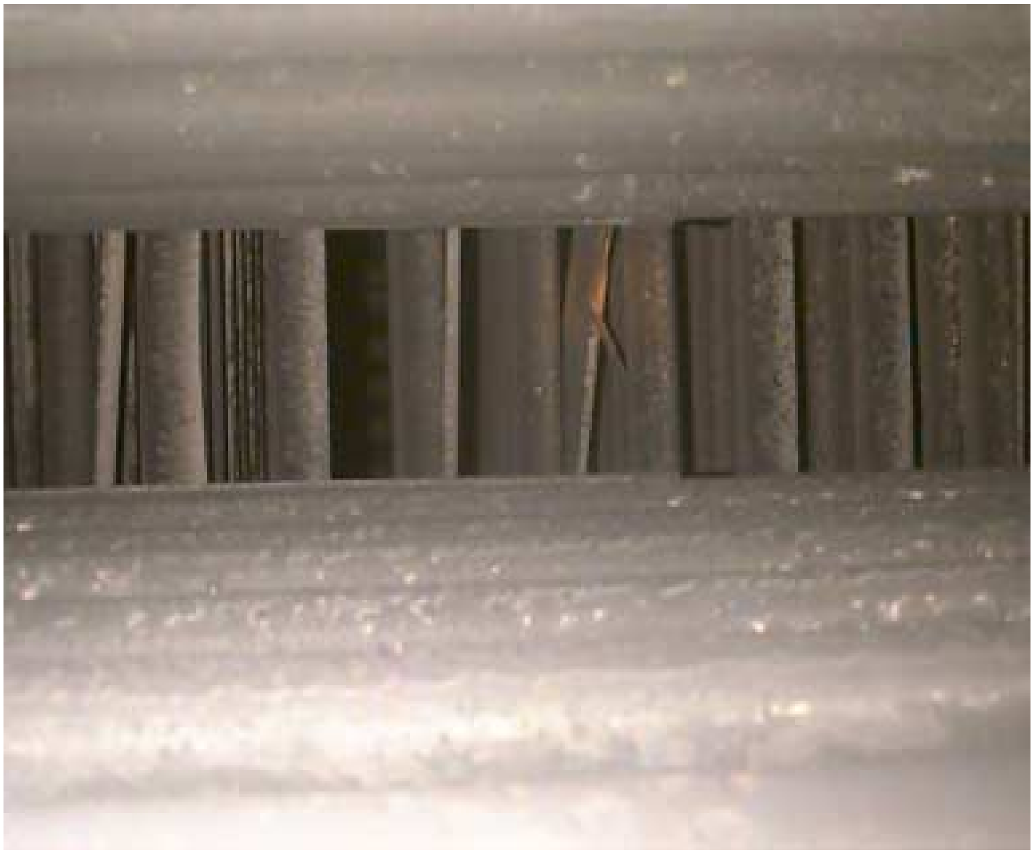


Figure 29 – HRSG Boiler Internals

3.14 Baghouse

3.14.1 Failure Identification

After running the Gasifier for several tries, flyash began leaking from the baghouse lower trough. Upon inspection, it was found that a good number of the bag supports had collapsed and the screw in the trough had warped. In addition, supports in the internal part of the baghouse hopper had pulled loose.

3.14.2 Description of Failure

During the firing of the Fines Combustor, the flue gas is filtered through the baghouse before it is emitted from the unit stack to atmosphere. During one of the runs of the Gasifier, fines were being consumed in the Fines Combustor. Upon pulling data after the run, the differential pressure on the baghouse reached a level that was too high. This caused all of the internal damage to the structure and to the bag supports.

3.14.3 Disposition of Failed Item

A unit outage was caused by the damage to the baghouse. The bags that had collapsed were removed and new supports installed. Considerable work to the trough and Screw Feeder was done. Supports for the Screw Feeder had come loose and the device was flopping in the trough. Repairs to internal structural supports and leaks were also completed.

3.14.4 Action taken

In order to prevent this from happening again several steps were taken. The baghouse differential pressure indication was a Pressure Differential Indicator with long tubes going to it that could plug. This was changed to inlet and outlet pressure indicators. The differential pressure of the structure would then be computed and displayed on the DCS for the operators. The bags are cleaned by back pulsing with air. This method was increased to its maximum potential. An alarm to alert operators was installed in the DCS.

3.15 Hot Gas Filter Level Detection

3.15.1 Failure Identification

The original level detection system in the Hot Gas Filter utilized 4 thermocouples located at different elevations in the filter. When a differential was realized between the cone section temperature and the gas temperature it was assumed that material was accumulating in the filter and an alarm would be initiated. If the condition could not be resolved within one hour, the manufacturer recommended manually shutting down the Gasifier. No Gasifier trips were automatically initiated. This system proved to be grossly inadequate and did not provide level indication or equipment protection.

3.15.2 Description of Failure

During Gasifier testing in mid-1997, the ceramic candle filters in the lower tier of the Hot Gas Filter were broken due to a high level of fines. The existing level detection system did not indicate that a problem was developing, and therefore, did not provide equipment protection.

3.15.3 Disposition of Failed Item

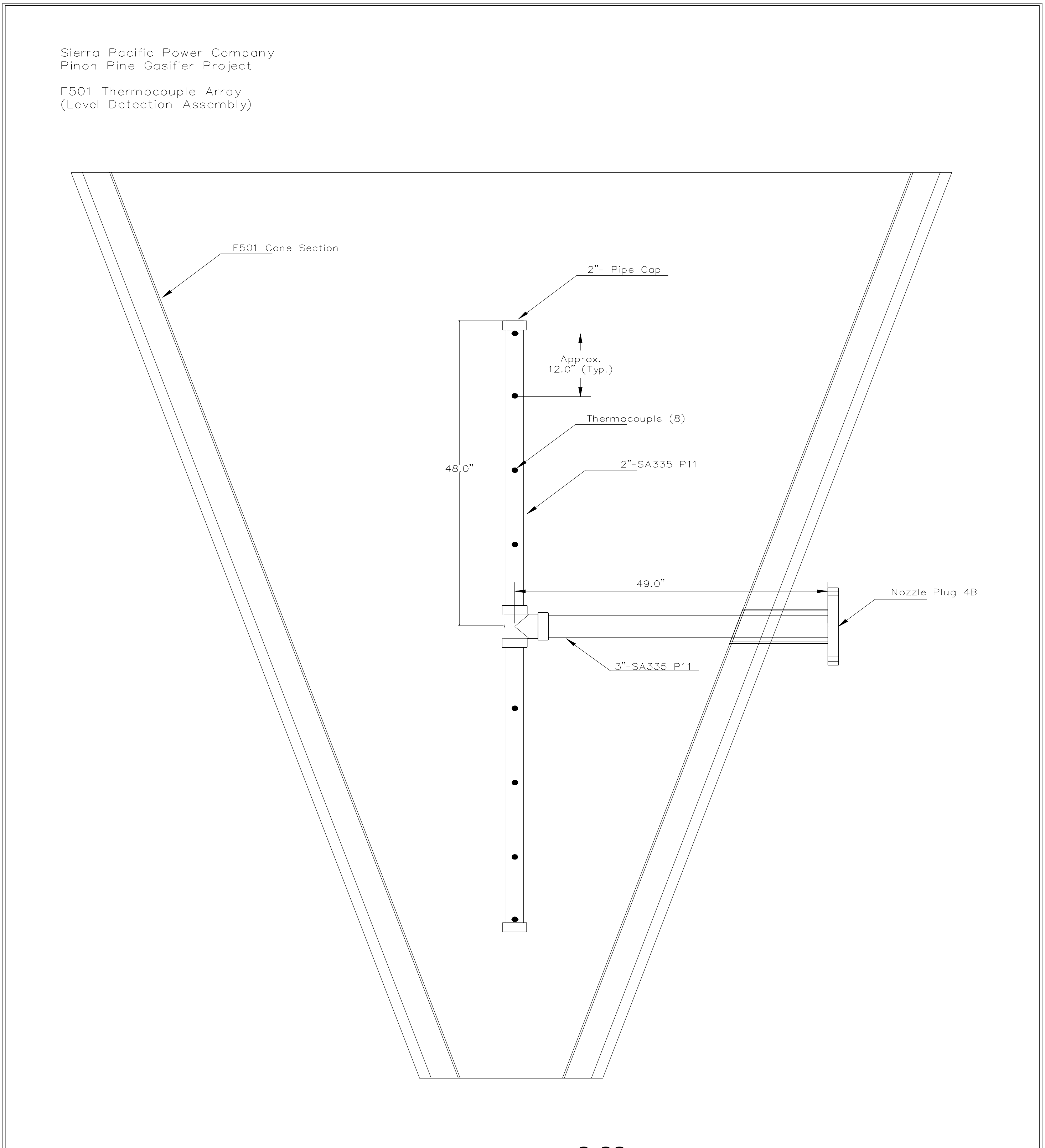
The existing level detection system was abandoned in place.

3.15.4 Action taken

The existing level detection system was replaced with nuclear level switches and an array of thermocouples. In 9/98, two nuclear level switches were installed at different elevations in the lower section of the Hot Gas Filter. The switches (high and high-high) were configured to give an alarm when a high level was detected, and to trip the Gasifier when a high-high (danger) level was detected. In addition, a vertical thermocouple array was installed near the center of the cone section of the filter. The intent of the thermocouple array was to give a continuous indication of level based on temperature differential.

Subsequent testing of the nuclear level detection switches and the thermocouple array proved that both systems were very reliable and provided excellent equipment protection. During numerous runs, level in the Hot Gas Filter has been successfully trended using the thermocouple array. Also, the nuclear level switches have served their purpose, shutting the Gasifier down when a dangerous level of fines was detected in the cone of the filter. Figure 30 shows the thermocouple array that was installed.

Figure 30 – Hot Gas Filter Thermocouple Array



3.16 Fines Combustor Feed Rate

3.16.1 Failure Identification

The Fines Combustor is intended to receive a continuous feed of fines from the Filter Fines Removal Package. The fines are burned in and the heat is recovered in the downstream HRSG. In several Gasifier runs, the feed rate has been erratic and caused the Fines Combustor to trip. It also resulted in downstream equipment damage.

3.16.2 Description of Failure

In all Gasifier start-up attempts prior to 4/99, the fines feed rate to the Fines Combustor proved to be unstable. The feed rate would surge, first delivering a low flow rate and then delivering so much fines that the incinerator would become overwhelmed. This resulted in numerous Fines Combustor trips, damage to the expansion joint between the unit and the HRSG, and damage to the downstream baghouse. The root cause of the surging is erratic feed rate of fines from the Filter Fines Feeder.

3.16.3 Disposition of Failed Item

In Gasifier tests performed after 4/99, the Fines Combustor was removed from service. All components that were damaged as a result of the feed rate problem were replaced.

3.16.4 Action taken

In order to continue with Gasifier testing, a solution to the erratic operation of the Fines Combustor had to be developed. The solution was to remove the Fines Combustor from service and divert the fines from the Filter Fines Removal Package to the Waste Silo. This was accomplished by adding a diversion line to the top of the Waste Silo. A diverter valve was also installed so that the operator could select the destination for the fines. In addition, nitrogen was piped to several elevations in the Waste Silo to allow a continuous nitrogen blanket to be applied when storing fines in the bin. The diversion system has been successfully utilized in numerous Gasifier runs. Figure 31 shows the system modifications.

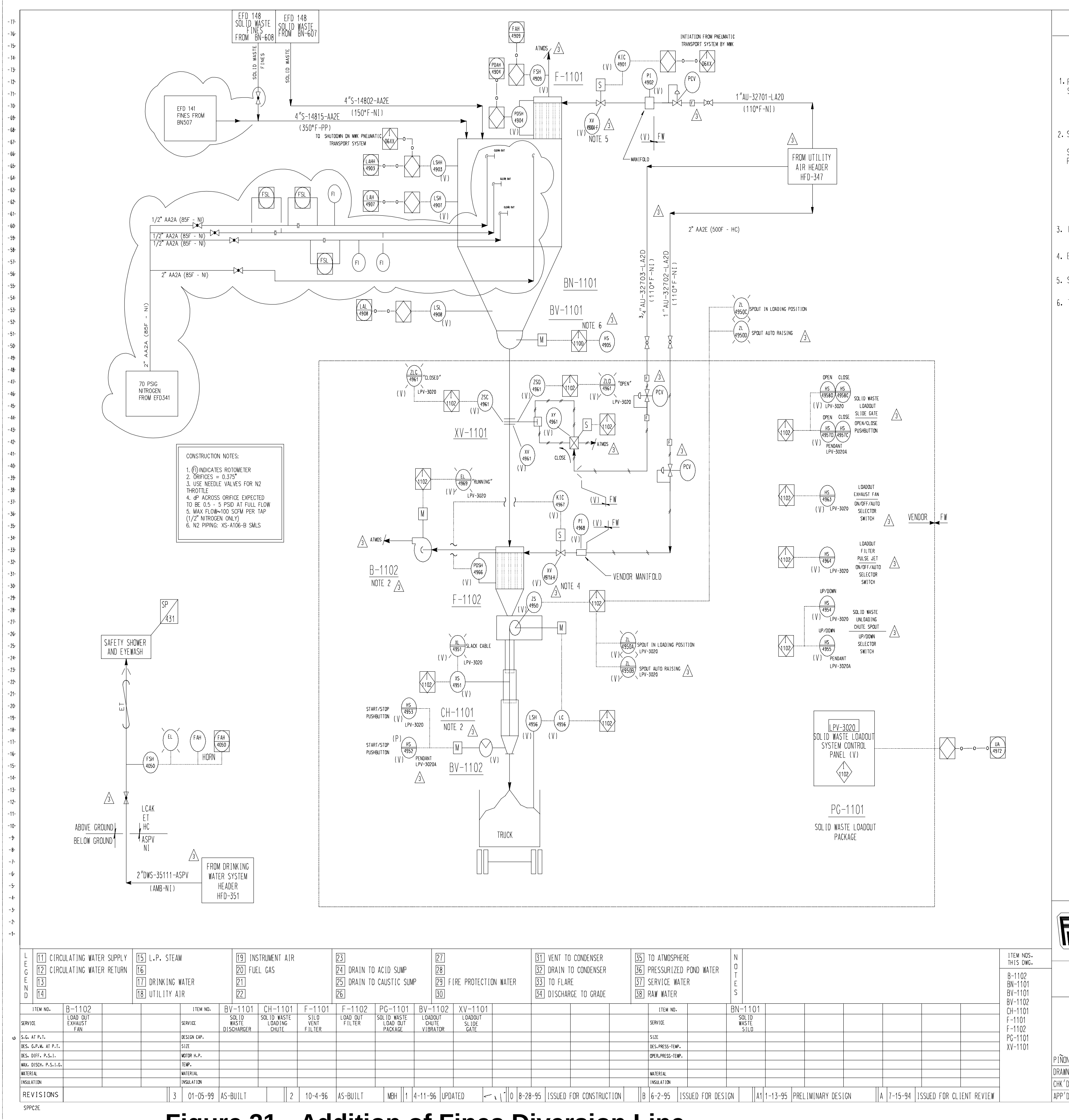


Figure 31 - Addition of Fines Diversion Line

3.17 Hot Gas Filter Fire

3.17.1 Failure Identification

During Gasifier testing in August 2000, elevated temperatures were observed on the hot gas filter. Inlet gas temperatures were maintained in the normal operating range, while outlet temperatures exceeded 1400°F. The source of the temperature excursion was found to be a fire in the hot gas filter.

3.17.2 Description of Failure

On August 10, 2000, Gasifier systems were being tested with no material present in the reactor. During the testing, which was conducted using extraction air only, Gasifier temperatures reached 800°F and pressure reached 200 PSIG. All testing was completed, and Gasifier pressure was lowered. As pressure dropped, smoke began emitting from the flare, and exit gas temperatures on the Hot Gas Filter began to increase. The unit was immediately secured and deluged with nitrogen.

Based on a review of data collected during the run and subsequent inspection of the filter vessel, it was determined that a fire had occurred in the Hot Gas Filter. Further review of the data indicated that stagnant material present in the Desulfurizer had become fluidized while lowering system pressure and was transported to the Hot Gas Filter. The material contained combustibles and ignited fines in the Hot Gas Filter.

The fire caused extensive damage to the filter assemblies and ceramic candle filters as shown by figure 32.

3.17.3 Disposition of Failed Item

Final disposition of the filter has not been determined. All damaged candles were scrapped.

3.17.4 Action taken

Repairs are being made to the Hot Gas Filter in anticipation of additional system testing. In addition, inert gas start-up schemes are being developed so that an oxidizing environment can be avoided prior to operating in gasification mode.

Figure 32 – Damage to Hot Gas Filter from Fire

4.0 UNIRAM Analysis Summary

Foster Wheeler USA Corporation (FW USA) contracted with ARINC to conduct an availability assessment of the Pinon Pine 106 Megawatt (gross) capacity Integrated Gasification Combined Cycle (IGCC) Power Plant. The plant, to be operated by Sierra Pacific Power Company (SPPCo), will be located at the Tracy Station near Reno, Nevada. The objective of the study was to determine the expected availability of the plant based upon design as described in the Technical Baseline document, the plant piping and instrument diagrams (P&ID), and the process flow diagrams (PFD). Technical assistance was provided by FW USA and the M. W. Kellogg Company (MWK) for the Power Island and the Gasification Island respectively.

ARINC Unit Reliability, Availability, and Maintainability (UNIRAM) software was used to model the plant. It considered thirty five (35) plant subsystems. The subsystem models included fault trees representing components that could cause the plant to fail or cause a capacity derating. The reliability and maintainability (R&M) expected of these components directly affects the plant equivalent forced (unplanned) outage rate (EFOR) and its equivalent availability (EA). The plant availability performance is based on the following: frequency of forced outages, expected time to restore failures, plant design and operational concept, and planned (scheduled) outage hours. With the exception of some Pinon Pine design specific equipment, most equipment represents commercially available, fully matured designs for which generic R&M data is available from a number of industry sources. R&M data for the plant specific equipment within the Gasification Island was provided by MWK.

UNIRAM models were developed for the following three modes of operation:

- Mode 1: Synthetic Gas (Syngas) Operation – Plant operates only on Syngas at a 97.8 Megawatt capacity and without natural gas backup, except to restart the plant following an unplanned or forced outage.

- Mode 2: Natural Gas Operation – Plant operates at a 90.4 Megawatt capacity only on natural gas in the combined cycle mode and without fuel transfer capability to Syngas.

- Mode 3: IGCC Operation – Plant operates at a 97.8 Megawatt capacity on Syngas with natural gas backup. Should a Syngas interruption occur, the plant is transferred to natural gas but operates at a 90.4 Megawatt capacity.

An important consideration in the study was start-up delays that occur after a component failure. These delays are due to the affects of Gasification Island cool down and the fuel transfer period required to return the plant to Syngas operation. These delays can be significant and depend on the mean time to repair (MTTR) of the components. Three restart delay cases were considered:

- Hot Restart (HR) – Applies to all components with an MTTR <36 hours, resulting in an 11.5 hour delay at a plant capacity of 75.3 Megawatts.

- Intermediate Restart (IR) – Applies to all components with 36 to 68 hour MTTR, resulting in a 42 hour delay at a plant capacity of 70.4 Megawatts.

- Cold Restart (CR) – Applies to all components with an MTTR >68 hours, resulting in a 142 hour delay at a plant capacity of 69 Megawatts.

The results of the UNIRAM analysis provide plant EA values of 72% in mode 1 and 94% in mode 2, exceeding the Pinon Pine Project EA goals of 70% and 85% respectively. Due to the serial configuration of the Gasification Island design, there are numerous single point failures that will result in loss of Syngas production and necessitating transfer to natural gas. This results in a high frequency of Syngas production failures which, when coupled with restart delays, extends the time that the plant must operate on natural gas to 119 days per year.

Of the 223 components represented in the plant IGCC model, 47 have MTTR that exceed 68 hours, requiring a cold restart delay of 142 hours. These cold start delays account for 34% of the total plant equivalent outage hours (1146 hours), compared to 10% of the total hours for the 144 components that are subject to hot restart delays of 11.5 hours. Improvements that reduce the frequency of plant failures and also reduce MTTR below 68 hours afford the best opportunity for the reduction in the EFOR of the plant. Due to the strong effect of unplanned maintenance downtime on EFOR, it is recommended that the Pinon Pine Project organization consider the development of a detailed, scheduled maintenance plan to implement annual plant turnarounds and a study to define the requirements for a predictive maintenance program.

5.0 Final Design Report

5.1 Stream Data

5.1.1 Introduction

The Pinon Pine Power Project is located at Sierra Pacific Resources Tracy Station near Reno, Nevada. The plant was designed to process 880 TPD of bituminous coal producing approximately 107 gross MWe of electric power.

The plant incorporates the air-blown KRW gasification technology, which produces a low-Btu gas. The gas will be used as fuel in a modified combined cycle power plant. The gasification system also includes hot gas removal of particulates and sulfur compounds from the fuel gas to produce a plant with exceptionally low atmospheric emissions. Desulfurization is accomplished by a combination of limestone injection into the KRW fluidized bed Gasifier and by a transport reactor system. Particulate removal is accomplished by high efficiency cyclones and a barrier filter.

5.1.2 Design Considerations

5.1.2.1 Location and Description of Site

The site selected for the Pinon Pine Power Project is the existing Tracy Power Plant located approximately 17 miles east of Reno, Nevada.

Tracy is a 724-acre site located in a rural portion of Storey County, Nevada. It is approximately 17 miles east of the Reno/Sparks area (population 250,000) and 15 miles west of the Fernley (population 7,000) Nevada. U.S. Interstate 80 is immediately adjacent and provides easy access to the site. The site is capable of accommodating the gasification plant, power plant facilities and all support facilities.

5.1.2.2 Area Geology

The site is located in the Truckee River Canyon. Late during the Pleistocene Epoch, the Truckee River Canyon was occupied by Lake Lahontan, which covered an area extending approximately 40.2 km (25 miles) south from Pyramid Lake. As the lake receded, the Truckee River began to down-cut into the lake deposits and subsequently formed the present canyon.

Where the river eroded away the lake sediments, it deposited fluvial channel (beds of river materials) and overbank deposits in their place. As a result, near-surface sediments at the site are composed primarily of river deposits consisting of minor clays, silts, sands, gravelly sands, sandy gravels, and coarse gravels. Lake deposits of clay, silt, sand, gravel, and calcareous tufa (porous stone containing calcium) may occur beneath the site. The most recent deposits are relatively thin eolian (windblown) deposits of silt and fine sand that mantle (cover) portions of the surface.

The hills south of the site consist mainly of olivine basalt (rock of volcanic origin containing a mineral silicate of magnesium and iron) and hornblende andesite (mineral consisting of silicate of calcium, magnesium, and iron in fine-grained volcanic rock) flows of the Pleistocene Kate Peak Formation. The site itself is relatively level to very gently rolling terrain with moderate relief. The site elevation is highest toward the south and gently slopes to the north toward the Truckee River. Relief in the surrounding area varies from very low in some of the intermountain basins to quite high in the adjacent mountain ranges. The average elevation at the site is approximately 1,295 meters (4,250 feet). Typical elevations of the nearby basins are between 1,219 and 1,829 meters (4,000 and 6,000 feet); elevations at the tops of bordering mountain blocks range between 1,829 meters and 2,438 meters (6,000 and 8,000 feet). The major structural elements in the general region surrounding the site are the Pah Rah Range to the north; the Virginia Range to the south; the Walker Lane Fault Zone to the northeast; and the Olinghouse Fault Zone, which trends east west along the southern flanks of the Pah Rah Range.

The Tracy Power Station project site is located in the western part of the Great Basin Tectonic Province. The site is located about 40.2 km (25 miles) from the adjacent Sierra Nevada Tectonic Province. This location, in a transition zone between two tectonic provinces, is one of the most seismically active (Seismic Zone 4) and complex regions of the United States.

Based on seismicity and style of faulting, the western Great Basin has been divided into three sub provinces (Selmmons, 1980): (1) the transition between the Sierra Nevada Frontal Fault Zone and the Walker Lane Fault Zone: (2) the Walker Lane Fault Zone: and (3) the Great Basin Zone east of Walker Lane Fault Zone. The Walker Lane Fault Zone is a 32.2-km (20 mile) wide, northwest trending zone of mainly right-lateral faults that extend from near Walker Lake northwest through Pyramid Lake and into the Modoc Plateau of California. North of Pyramid Lake, the faults tend to radiate more northward and the Walker Lane Fault Zone becomes wider and more diffuse overall. The Walker Lane faults south of Pyramid Lake are relatively quiet compared to the faults in the other sub provinces, although active faults are abundant in northeast California. The closest active fault to the site within the Walker Lane is the Pyramid Lake strand, which is approximately 22 kin (15 miles) from the site. It has an estimated Maximum Credible Earthquake value of 7.5. (A maximum Credible

Earthquake, MCE, is the most serious earthquake that can be hypothesized from known geologic characteristics.)

East of the Walker Lane Fault Zone, faults are generally north-south trending normal faults. This part of the Great Basin has had several historic earthquakes of magnitude 6.6 to 7.7, including the 1954 Rainbow Mountain Fairview Peak, and Dixie Valley earthquakes. Epicenters along the Dixie Valley-Fairview Peak area continue south across the Walker Lake Fault Zone and intersect the Sierra Nevada Frontal Fault Zone. Forty-four earthquakes of magnitude greater than 5.0 have been reported in the area between 1852 and 1992.

The Truckee-Verdi-Reno-Olinghouse Transverse Fault Zone is of particular concern because it passes near the proposed site and includes the Olinghouse Fault Zone. The active portion of the Olinghouse Fault Zone extends from 16 km (10 miles) east of Reno along the north side of the Truckee River Canyon, passes through Olinghouse Canyon, and abruptly arcs to the northeast to terminate against a fault of the Walker Lane Fault Zone for a total length of 23 km (14 miles). In 1869, a series of earthquakes with magnitudes up to 6.7 occurred along this fault producing surface rupture north, west, and east of Tracy. This fault is located approximately 1.6 km (1 mile) from the proposed site at its closest approach; it has an estimated Maximum Credible Earthquake value of 7.1.

The largest historical seismic events close to the project site are the 1852 event with a possible magnitude of 7.0 and the three December 1869 earthquakes with estimated magnitudes of between 5.5 and 6.7. The 1852 earthquake was located just south of Tracy Station; however, the precise location of the earthquake has not been determined because information is based solely on descriptions by members of the Paiute Indian Tribe who were camping south of Pyramid Lake near Wadsworth. The epicenters of the 1869 earthquakes were located on the Olinghouse Fault Zone 16 to 39 km (10 to 24 miles) east of Reno. This zone is where the surface rupture occurred and includes the closest approach of the fault to the site.

The extent of wetlands is sufficiently limited to the extreme northern portion of the property so that siting new facilities can be done to avoid permanent wetland disturbance.

5.1.3 Environmental, Safety & Hazard Considerations

The Pinon Pine Power Project complies with environmental, health, safety and socioeconomic (EHSS) statues and regulations. The probability of EHSS compliance is essentially assured. EHSS risks will be minimized. Health and safety plans, based on existing experience, are referenced. Adverse environmental impacts will be at acceptable levels, and socioeconomic impacts will be beneficial. Mitigation measures identified in the Final Environmental Impact Statement (EIS) have been incorporated into the Record of Decision.

The probability of EHSS compliance for the Pinon Pine Project is essentially assured because of the understanding of permit and regulatory requirements, and the adherence to safety regulations and codes.

Construction and operation of the Pinon Pine Power Project was undertaken in a safe manner and in compliance with the general requirements of the Occupational Health and Safety Act (OSHA) PL 91-596, Part 1926 for construction and Part 1910 for operating.

Hazardous wastes are handled in full compliance with OSHA Standard 29 CFR Part 1910.1200. These requirements relate to the Hazard Communication/Right-to-Know Program.

Presently there are no specific OSHA requirements in Nevada for the protection of workers in gasification plants. Guidelines for workers health and safety at coal gasification facilities have been recommended by the National Institute of Occupational Safety and Health (NIOSH) in:

- "Recommended Health and Safety Guidelines for Coal Gasification Pilot Plants", Department of Health, Education and Welfare (DHEW) (NIOSH) Publication No. 78-120, January 1978.

- "Criteria for Recommended Standard, Occupational Exposure in Coal Gasification Plants", DREW (NIOSH) Publication No. 78-191, September 1978.

5.1.4 Supplied Utilities

5.1.4.1 Coal Supply

The Gasifier is designed to operate with a wide variety of coals. For each coal property, there is a considerable range acceptable to the Gasifier and the flexibility of fuel supply is a major advantage of this process. During the operation of the Pinon Pine Power Project the predominant fuel was low sulfur coal from the western U.S. The western coal used during this time frame was SUFCO coal from Utah.

Economic forecast for fuel prices projects that these coal prices will remain stable in the future, and will not increase at rates exceeding general inflation. All deliveries are made by railcar to the Tracy facility.

5.1.4.2 Limestone

Sorbent requirements for in-bed desulfurization have been evaluated for the life of the project. High quality limestone supplies suitable for project needs are available from several active producers in Nevada and western Utah. Although a variety of sorbents of various qualities are suitable for use as sorbents in the gasification process, optimum sulfur removal efficiency is achieved with maximum concentration of calcium carbonate.

Expected project requirements are approximately 80 tons/day of 90% + $CaCO_3$ limestone. The material is supposed to be delivered to the site as dry limestone sand so that no additional preparation is needed prior to injection into the Gasifier. Dust-free truck transportation and storage is provided.

5.1.4.3 Natural Gas

Tuscarora and Paiute natural gas transmission lines are available to provide fuel for the Pinon Pine Gas Turbine Generator. The gas turbine is designed to operate on the following fuel mixtures

- 100% natural gas
- 100% Gasifier product gas
- Natural gas & product gas blend (within design limitations)

5.1.4.4 Electric Power

The plant is within Sierra Pacific Power Company's service area. Construction power was provided from existing buses, with electric power of 4.1 kV, approximately 100 feet from the project boundary.

5.1.4.5 Water Requirement and Availability

For the project, cooling water make-up will be taken from the existing cooling pond, which is supplied from the Truckee River, which adjoins the site, using an additional pump and existing water rights. Raw water for the demineralization train will be taken from deep wells. Two wells are currently in service and a new well with existing water rights will be added. Sufficient water rights exist to provide the

Tracy site with the required water for the gasification process, the steam cycle, the cooling water and the balance of the plant through the year 2030.

5.1.4.6 Transportation System

Both highway and rail transportation were used during the construction and operation phases of the project. Tracy Power Plant is located adjacent to I-80, which is a four-lane interstate highway. The site is served by the main line of the Southern Pacific Railroad, which runs through the property. An extended rail spur was also added at site for the delivery of coal. Air transportation is available through Reno Tahoe International Airport, which is approximately 20 miles from the Tracy site.

5.1.4.7 Solid Waste Handling

Cooled solid waste consisting of ash, fines and sulfated limestone from the sulfation unit is conveyed continuously to the solid waste storage silo. The solid waste silo is sized for three days of storage to handle the solid waste production over the weekend without the need of the truck load-out operation.

The solid waste material in the silo is dumped into covered trucks during the day shift operation. The silo is equipped to minimize dusting during the truck loading operation. The solids waste removed from the silo is transported to a local landfill.

5.2 Project Description and Equipment List

Foster Wheeler U.S.A. Corporation's scope of work was to engineer, design and purchase equipment for installation in the Power Island, which is defined by the following sections:

- Section 100 Solids Receiving, Storage and Crushing
- Section 200 Oxidant Compression and Supply
- Section 300 Coal Gasification

- Section 400 Gasifier Stream Heat Recovery
- Section 500 Gasifier Stream Particulate Removal
- Section 600 Desulfurization
- Section 700 Gas Turbine Generator
- Section 800 Steam Turbine Generator and Heat Recovery Steam Generator
- Section 900 Recycle Gas Compression
- Section 1000 Waste Water Treatment
- Section 1100 Solids Waste Handling
- Section 1200 Balance of Plant

An equipment list, which highlights the major equipment contained in these twelve sections, is located in the appendix of this document. The sections listed identify areas of the project that are located either in the Power Island or the Gasifier Island. For the purpose of clarity, this description will group the sections so they best follow the process.

5.2.1 Power Island

The Power Island can operate independently of the Gasifier Island. The Power Island is divided into the following areas:

- Section 100 Solids Receiving, Storage and Crushing
- Section 700 Gas Turbine Generator
- Section 800 Steam Turbine Generator and Heat Recovery Steam Generator
- Section 1000 Waste Water Treatment

- Section 1100 Solids Waste Handling
- Section 1200 Balance of Plant

5.2.2 Solids Receiving, Storage and Crushing (Section 100)

5.2.2.1 Raw Coal Receiving and Storage

Raw coal is received at the plant by train. The coal is 2 inches x 0 in size and has a density of 45/55 lbs/ft^3. The shipments can consist of up to eighty-four 100-ton railcars which would be required every seven days assuming at design Gasifier.

Railcar unloading is designed to be a fully automatic system. The rail cars move through the unloading enclosure at ¼ mph and as individual cars reach the unloading point a wayside rail energizes the car opening solenoid. The raw coal unloading and conveyor system was sized to handle an 84-railcar train unloading operation in a four-hour period, at a design rate of 2,250 std. tons/hr.

The coal is received at the unloading station and transferred to the coal storage dome. The unloading station consists of two receiving hoppers; each equipped with a belt type unloading feeder, which feeds the raw coal to the raw coal transfer conveyor. Coal is weighed in transit by the raw coal receiving scale located at the tunnel exit of the raw coal transfer conveyor.

The raw coal sampling system is designed to remove a representative sample of the coal being conveyed on the raw coal transfer conveyor. The primary sampler is designed to sweep coal from the raw coal transfer conveyor onto the primary sample feeder. The sampler is designed to remove 81 pounds of raw coal with each sweep. The cutter is designed to make 25 sample sweeps per hour.

The coal is stored in a 250 foot diameter field-erected storage dome which was sized to stockpile 16,400 std. tons of coal. This is approximately twenty day's supply at design Gasifier operation.

The raw coal is stockpiled and reclaimed in the coal dome by an automated Stacker/Reclaimer assembly. The stacker distributes the raw coal in a 220^{o} arc around the perimeter of the dome. The Reclaimer drags the raw coal to a vibratory feeder and onto the raw coal collecting conveyor. The raw coal collecting conveyor transfers the coal to the crushing station for sizing and screening.

5.2.2.2 Coal Crushing and Screening

The raw coal is fed to the coal crusher to reduce the material size from 2" x 0 to the required ¼" x 0. The ¼" x 0 product-size material is transported into the coal storage silo by the sized coal conveyor.

The coal silo is designed to hold 24-hours of feed to the Gasifier at design operation. At design operation the silo would be filled daily during an 8-hour operating period of the crusher and the elevating conveyor. The Gasifier feed elevating conveyor is provided to transport materials from the coal silo, the limestone silo and the coke breeze silo to the Gasifier coal and limestone feed package.

5.2.2.3 Coal, Coke Breeze and Limestone Feeding

Dried coke breeze is received in the plant via trucks. The coke breeze is transferred from the truck pneumatically to an 800 ton capacity coke storage silo using the truck-trailer's own pneumatic blower. Exhaust air from the filling operation is vented through the coke silo exhaust filter.

The coke breeze is gravity fed onto the coke silo discharge feeder belt for transfer to the Gasifier feed elevating conveyor. The coke feeder is designed to handle between 15 and 50 standard tons per hour of ¼" nominal coke breeze.

Provisions are also included for transporting coke breeze to the Sulfator limestone feed hopper. Material from the coke storage silo is fed to the coke transporter by reversing the direction of the coke silo discharge feeder belt. The coke transporter is then used to pneumatically convey the material to the limestone feed hopper.

Sized limestone is also received at the job site via trucks with pneumatic trailers on a daily basis. The sized limestone is conveyed pneumatically to the limestone silo using the truck-trailer's own pneumatic blower. Exhaust air from this filling operation is vented through the limestone silo exhaust filter.

The limestone is gravity fed onto the limestone silo discharge feeder belt for transfer to the Gasifier feed elevating conveyor. The limestone feeder is designed to handle between 1.5 and 5 standard tons per hour of 650-micron limestone.

Provisions are also included for transporting limestone to the Sulfator limestone feed hopper. Material discharged from the limestone silo is fed to the limestone transporter by reversing the direction the limestone feeder belt. The limestone transporter is then used to pneumatically convey the material to the limestone feed hopper.

5.2.3 Gas Turbine Generator (Section 700)

A General Electric Model MS6001FA Gas Turbine Engine (70.1 MW ISO rating) has been selected as the prime mover for the Tracy 4 -Pinon Project. The engine's output shaft power will be reduced in rotative speed in a gearbox, from the optimum-efficiency value for a gas turbine of this size to 3600 RPM. Mechanical power will then be converted to electrical power in a once-through air-cooled synchronous generator.

The gas turbine generators expected operating characteristics using Syngas fuel at annual-average ambient air conditions (50° F, 12.56 psia, 20% RH) are as follows:

Output:	60,990 kW (1)
Heat Input:	568.4 MMBtuLHV/h(2)
Exhaust to HRSG:	1,422,000 LB/hr
temp:	1,103°F

(1) = at the generator terminals, 0.85 pf
(2) = chemical release, i.e. does not include Syngas sensible heat

Available thermal power in the exhaust gases will be captured in a heat recovery steam generator to drive a condensing steam turbine generator.

The gas turbine has an eighteen stage axial flow compressor with modulated inlet guide vanes. Interstage extraction is used for turbine nozzle and wheelspace cooling. Because the blading material in the compressor has high corrosion resistance, a coating is not required. Approximately 20% of the total compressor discharge air is extracted from the engine for the air-blown Gasifier, and returns as part of the Syngas fuel.

The gas turbine engine is provided with a conventional array of auxiliary systems and accessory devices, supplemented where necessary by special provisions for Gasifier air extraction and combustion of Syngas

5.2.4 Steam Turbine Generator and Heat Recovery Steam Generator (Section 800)

A heat recovery steam generator is provided to recover the heat in the gas turbine exhaust gas stream. Two (2) levels of steam will be generated: Level 1 = 1006.7 psia, Level 2 = 59.1 psia

Steam generated in the HRSG at 1006.7 psia, and high pressure steam generated in the Gasifier Island, are combined, superheated in the HRSG and sent to the steam turbine generator at 950 psia, 950°F for expansion. The 59.1 psia steam generated is superheated and sent at 55 psia, 360°F to the Deaerator for heating and stripping with the excess sent to the turbine generator.

5.2.5 Stack

The exhaust gasses exiting the heat recovery steam generator and Gasifier island will vent to the atmosphere via a 28 foot dia. x 225 foot high concrete shell stack. The stack contains two insulated steel flues; one is 13 feet in diameter and one is 4 feet in diameter.

The 13-ft diameter flue is dedicated to gas turbine exhaust while the remaining flue is dedicated to the gasification plant. The stack is equipped with test ports, interior access lighting, aviation warning lights and lightning protection.

5.2.6 Steam Turbine Generator

The steam turbine generator is a condensing type unit with extraction at nominally 485 psia providing steam, after pressure control and desuperheating, to the Gasifier at 420 psia, 700° F. High pressure steam letdown is used if and when low throttle steam rates cause the extraction pressure to fall below that required to provide 420 psia steam. This letdown will provide steam for injection at the gas turbine generator at 420 psia, 700°F for NOX control when operating on natural gas.

The steam turbine exhausts into a surface condenser. Cooling water from Section 1200 condenses the exhaust

steam at 2 in. Hg based on normal Gasifier load at 50°F ambient temperature. Condensate is pumped from the condenser by the hotwell condensate pumps through the condensate preheater in the heat recovery steam generator and then to the Deaerator. Venting of the condenser is accomplished by a vacuum pump system.
HP boiler feed water is pumped from the Deaerator to the high pressure evaporator and Section 300, Gasification, and Section 600. Sulfation by the high pressure boiler feedwater pumps. High pressure boiler feedwater to the high pressure evaporator is preheated in economizer sections of the heat recovery steam generator.

A Deaerator is supplied to deaerate returned condensate and demineralized water make-up. Deaerated low pressure boiler feed water is pumped to the low pressure evaporator by the low pressure boiler feed water pumps. Boiler feedwater to the low-pressure evaporator is preheated in an economizer section of the heat recovery steam generator.

The steam turbine generator has an output of 46.226 kW at a power factor of .85, 329,133 LB/hr throttle flow, 11,855 LB/hr extraction @ 485 psia, 15,304 LB/hr induction at 54 psia and 360°F and 2.0 in. HgA exhaust backpressure.

5.2.7 Gasifier Island

The Gasifier Island is part of the Pinon Pine Power Project which has as its objective to provide a 107 MWe (gross) Integrated Gasification Combined Cycle (IGCC) power plant to meet the needs of the SPPCo. while demonstrating the technical, economic and environmental viability of a commercial scale IGCC power plant. The design of the power plant is based on utilizing a KRW air blown, fluidized-bed coal Gasifier installed in the Gasifier Island to produce a fuel gas for use by a combustion Gas Turbine which is capable of utilizing a low Btu fuel gas. Also, a hot gas clean up system is provided in the Gasifier Island to remove particulates and to minimize SO_2 and

NOX emissions.

The M. W. Kellogg Company's (MWK) scope of work was to engineer, design and purchase equipment for installation in the Gasifier Island which is defined by the following areas:

- Section 200 - Oxidant Compression & Supply
- Section 300 - Coal Gasification
- Section 400 - Gas Stream Heat Recovery
- Section 500 - Gas Stream Particulate Removal
- Section 600 – Desulfurization
- Section 900 - Recycle Gas Composition

During normal base load operation, the Gasifier system will:

a. Produce 285,000 LB/hr Syngas

b. Export 156,000 LB/hr of steam to the combined cycle area

c. Consume: 880 TPD Raw Coal and 50 TPD Limestone

d. Discharge 120 TPD of LASH (limestone/ash mixture) for deposit at landfill

5.2.7.1 Oxidant Compression and Supply (Section 200)

Extraction air for the Gasifier island is imported from the power islands gas turbine. The extraction air provides combustion air for the Gasifier, air for regeneration of the desulfurization sorbent, air for coal and limestone feed pressurization and transport air for feeding coal and limestone into the Gasifier.

The extraction air must be cooled and compressed before it can be used in normal Gasifier operations. To minimize power consumption during compression, the extraction air is cooled by three exchangers. The hot extraction air first passes through the air recuperator exchanger where it is cooled by discharge from the booster air compressor. The extraction air then passes through the air precooler exchanger where it is cooled by preheating boiler feed water. Finally the extraction air passes though the trim cooler exchanger where cooling water is used to achieve the remaining cooling. A knockout drum is provided downstream of the trim cooler to remove any water condensed from the air during cooling. Any water collected in the knock out drum will be sent to the waste water treatment system.

Air exiting the knockout drum is compressed by the booster air compressor to approximately 325 psig. A portion of this air is cooled by cooling water in the transport air cooler and splits into two streams. The first stream is cooled and used to transport coal and limestone (or coke breeze) into the Gasifier. The second stream is fed to the suction of the pressurization air compressor.

The major portion of the air exiting the boost air compressor is reheated in the air recuperator exchanger and used routed to the Gasifier air tube. A small portion of the air is routed to the transport regenerator where it is utilized to regenerate the desulfurization sorbent.

A portion of air exiting the transport air cooler is compressed by the pressurization air compressor and routed to the pressurization air receiver. The receiver dampens out pressure fluctuations and serves as a surge vessel. The compressed air is used directly for coal/limestone feed pressurization.

5.2.7.2 Coal Gasification (Section 300)

This area contains the solids feed system and the Gasifier with its associated cyclone. Solid feed consists of the coal to be gasified and limestone sorbent used for capture of sulfur compounds emitted during gasification.

Coal and limestone (as well as coke breeze used during start-up) are fed from a single conveyor to the coal and limestone feed package. The feed package is comprised of a series of bins, which are designed to elevate the feed from atmospheric to the Gasifier operating pressure. The coal and limestone package is also equipped with filters to capture fugitive dust emission and return them to the system.

The feed package provides a continuous feed of coal and limestone to the Gasifier. Coal, coke or limestone is pneumatically transported to the Gasifier central feed tube. Combustion air is fed to the same location and the streams merge to form a central jet. The coal is quickly devolatilized and the remaining char and limestone enters the Gasifier bed.

Combustion of char and gas occurs within the jet to provide the heat necessary for endothermic devolatilization, gasification and desulfurization chemical reactions. Extraction steam from the steam turbine is also fed to the Gasifier bed. The primary gasification and combustion reactions which occur in the Gasifier are:

$C+H_2O$ ----> $CO+H_2$
$C+C0_2$ ----> $2C0$
$CO+H_20$ ----> CO_2+H_2
$C+0_2$ ----> CO_2

Carbon monoxide and hydrogen form the major combustible constituents of the product gas. Methane and other hydrocarbons are produced in lesser quantities primarily from the devolatilization process. The operating temperature of the Gasifier is sufficiently high to crack any tars or oils that might be produced.

Coal gasification also results in the release of sulfur from the process, which is primarily in the form of hydrogen sulfide. At Gasifier operating conditions the limestone sorbent fed with the coal quickly calcines and reacts with the H_2S according to the following reactions:

$CaCO_3$ —> $CaO + CO_2$
$CaO+H_2S$ —> $CaS+H_2O$

The amount of H_2S that is captured is limited by chemical equilibrium. With the low sulfur SUFCO Coal, approximately 50% of the sulfur released from the coal is removed from the gas by reaction with CaO. Sulfur exiting the Gasifier in gaseous form is captured in the transport Desulfurizer.

The product gas exiting the top of the Gasifier contains a significant quantity of entrained solids, consisting of char (unconverted coal), ash, and sorbent. The gas enters the Gasifier cyclone, which removes most of the solids. Gas from the cyclone is directed through the product gas cooler and the product gas trim cooler for heat recovery.

Solids collected by the Gasifier cyclone returned to the Gasifier via the cyclone dip leg. Recycle gas from the recycle gas compressor is used to fluff the dip leg to facilitate flow of solids back to the Gasifier bed.

As the carbon in char is consumed the particles become enriched in ash. The ash particles tend to agglomerate and along with dense calcium sulfide/oxide particles, separate from the char bed because of different density and fluidization characteristics. This separation occurs primarily in a region that surrounds the central feed tube at the bottom of the Gasifier. These solids are further cooled in the Gasifier annulus by a counter current stream of recycle gas. The spent solids (LASH) leaving the Gasifier pass through the ash grinder and the ash feeder and are transported to the ash collection package.

The ash collection package is comprised of a series of bins which are designed to reduce the LASH from the Gasifier operating pressure to the Sulfator operating pressure. The ash collection package is equipped with filters to capture fugitive dust emission and return them to the system.

The Gasifier and Sulfator start-up heater is provided to preheat the gas turbine extraction air. The heater is utilized for drying out refractory and for preheating the Gasifier and downstream equipment during start-up.

5.2.7.3 Gas Stream Heat Recovery (Section 400)

Product gas from the Gasifier cyclone is cooled to 1000°F by the product gas cooler and the product gas trim cooler. The cooling is accomplished by generating steam from boiler feed water supplied from the Gasifier steam drum. Circulation through the product gas is by natural convection.

The Gasifier steam drum operates at 1075 psia (nominal) and is supplied by boiler feed water from section 800. The high pressure boiler feed water is split into several streams. A portion is sent directly to the air precooler and the recycle gas cooler. The heated boiler feed water exiting these exchangers is routed to the Gasifier steam drum. The remaining boiler feed water flows directly to the Gasifier steam drum and the heat recovery steam generator steam drum. Boiler feed water from the Gasifier steam drum is used to supply the regenerator effluent gas cooler and the primary solids cooler. Boiler feed water going to the heat recovery steam generator is first preheated in the economizer section.

Steam from the Gasifier steam drum combines with superheated steam from the heat recovery steam generator. The combined steams are passed through the superheater section of the heat recovery steam generator in order to superheat it to 600°F prior to delivery to section 800. Continuous blowdown from the Gasifier steam drum is combined with blowdown from the heat recovery steam generator and also returned to section 800.

5.2.7.4 Gas Stream Particulate Removal (Section 500)

This section provides final cleanup of particulates in the product gas stream and collection of all spent solids prior to final processing.

Desulfurized product gas from the desulfurization section still contains a small quantity of particulates. This stream is sent to the hot gas filter, which essentially removes all of the remaining particulates. The hot gas filter is a ceramic candle type filter, which utilizes back pulse gas for cleaning. Candle elements used for filtration are housed in a steel vessel with access capability for replacement of candles. The particulate free desulfurized gas exits the filter and is sent to the gas turbine.

Blowback gas for cleaning of the ceramic filter elements is provided by the recycle gas booster compressor. Fines removed by the filter elements collect in the bottom of the hot gas filter and are removed by the filter fines screw cooler. The hollow screw cooler uses a heat transfer fluid to cool the fines prior to discharging them into the filter fines collection package.

The fines collection package is comprised of a series of bins which are designed to reduce the filter fines from the hot gas filter operating pressure to the Fines Combustor operating pressure. The fines collection package is equipped with filters to capture fugitive dust emission and return them to the system.

Filter fines are removed from the fines collection package by a screw and pneumatically transported to either the Fines Combustor or the LASH silo. Recycle gas is used to transport the fines to the Fines Combustor and 70-psi nitrogen is used to transport the fine to the LASH silo.

Most of the particulate free desulfurized product gas exiting the hot gas filter is either routed to the gas turbine or the flare. A fraction of the product gas is cooled in the recycle gas cooler and fed to the recycle gas compressor. The recycle gas is used for fluidizing, cooling and transporting solids in the gasification process.

5.2.7.5 Desulfurization (Section 600)

Section 600 desulfurizes the product fuel gas and solid waste that are produced during the gasification process. This system serves the following functions:

1. Desulfurizes the product fuel gas prior to delivery to the hot gas filter.

2. Combustion of residual char in the ash and fines collected from gasification.

3. Capture of SO_2 from both the residual char combustion and the Desulfurizer regeneration effluent gas.
4. Oxidation of calcium sulfide (CaS) produced in the Gasifier to calcium sulfate.

5.2.7.6 Transport Desulferizer

The product gas desulfurization system is comprised of the Transport Desulfurizer and the Transport Regenerator. Sulfur compounds are removed from the gas by a zinc titanate based sorbent. The target for sulfur compounds in the product gas to the gas turbine is less than 20 ppmv. The mildly exothermic absorption reactions result in a small increase in the fuel gas temperature

Product gas from the Gasifier is cooled to approximately 1000°F and passed through the Desulfurizer feed cyclone where entrained particulates are removed. The particulates collecting in the cyclone dip leg are removed by the fines feeder and pneumatically transported to the hot gas filter. The sour product gas exiting the top of the cyclone is routed to the mixing zone at the bottom of the Desulfurizer riser.

The absorption of gaseous sulfur compounds takes place in the narrower riser section as the gas and sorbent flows upward and into the Desulfurizer cyclone. Bulk separation of the clean product gas and sorbent takes place in the Desulfurizer cyclone. The sorbent separated by the cyclone is collected in the Desulfurizer standpipe. The desulfurized product gas is routed to the hot gas filter where it undergoes final particulate removal before being fed to the downstream users.

The sorbent leaving the Desulfurizer riser is partially sulfided. A portion of the sulfided sorbent is transferred to the transport regenerator riser and the remainder is recirculated to the Desulfurizer.

The portion of sulfided sorbent withdrawn from the Desulfurizer standpipe flows to the mixing zone at the bottom of the transport regenerator. Regeneration air from the air recuperator is preheated by the sorbent regeneration air heater before being fed to the mixing zone in the transport regenerator. The sulfided sorbent is regenerated by air in a highly exothermic reaction as the sorbent and air flow up the regenerator riser.

The gas exiting the regenerator riser is approximately 1200°F. The exit temperature is controlled by varying either the inlet temperature of the regeneration air, the circulation rate or the sulfur loading of the sulfided solids. The mixture of regenerated sorbent and gaseous products of regeneration leaving the riser enter the regenerator cyclone where bulk separation of the solids and gaseous phases occurs.

The regenerated sorbent is returned to the Desulfurizer standpipe. The $S0_2$ rich gas from regeneration is cooled in the regenerator effluent cooler and routed to the Sulfator for SO_2 capture.

A sorbent make-up system is provided to load fresh sorbent into the Desulfurizer while the Gasifier is in operation. The sorbent will be added as required to maintain sorbent inventory and reactivity. Fresh sorbent from bulk storage is first vacuumed into the sorbent storage hopper. The sorbent is then gravity fed to sorbent feed hopper and pressured into the Desulfurizer.

5.2.7.7 Sulfator

With the exception of the small quantity of sulfur in the product gas to the gas turbine, most of the sulfur in the coal is ultimately disposed of in either the Sulfator or the Fines Combustor. It should be noted that the following reactions, which occur in the Sulfator, are highly exothermic and may not proceed to completion.

$$S + 02 \rightarrow SO_2$$
$$CaO + SO_2 + 1/2\ O_2 \rightarrow CaSO_4$$
$$CaS + 20_2 \rightarrow CaSO_4$$

The Sulfator is a bubbling bed reactor, which is fluidized by air supplied by the Sulfator air compressor. Solids exiting the Gasifier annulus contain unconverted calcined limestone, sulfided limestone and ash (LASH). These solids are conveyed from the ash feed hopper to the Sulfator by cooled recycle gas from the recycle gas cooler. Regeneration effluent gas from the desulfurization system is also fed to the Sulfator for capture of SO_2 by reaction with the unconverted calcined limestone in the solids from the Gasifier. Small recycle gas streams (transport and pressurization gas) from the ash feed system and the fines collection system are also combusted in the Sulfator.

The Sulfator is operated at essentially atmospheric pressure in order to maximize SO_2 capture and sulfide oxidation. Combustion air for the Sulfator is supplied by the Sulfator air compressor. The Sulfator temperature is maintained at about 1600°F by generating saturated steam in the primary solids cooler. The cooler is supplied with boiler feed water by natural convection from the Gasifier steam drum. Steam generated by the primary solids cooler is collected in the Gasifier steam drum.

Flue gas leaving the Sulfator passes through the Sulfator cyclone to remove entrained particulates. The flue gas then mixes with flue gas from the Fines Combustor prior to passing through heat recovery steam generator.

Solids leaving the Sulfator are cooled by the Sulfator solids screw cooler. These cooled solids are fed to the Sulfator solids transfer pressure pot where they are pneumatically transported to the solid waste silo.

It is anticipated that sufficient quantities of unconverted calcined limestone will be present in the Sulfator to react with the sulfur compounds. If necessary, fresh limestone can be added to the Sulfator using the limestone feed hopper. Instrument air is used to pressurize the hopper and transport fresh limestone to the Sulfator during normal operation. Any fugitive dust emissions are captured by the limestone feed hopper vent filter and returned to the hopper.

5.2.7.8 Fines Combustor

The Fines Combustor is a fired burner that is used to combust any residual carbon fines that are produced during gasification. These residual fines are collected in the hot gas filter and transferred to the fines collection package. Filter fines are pneumatically conveyed from the fines package to the Fines Combustor using recycle gas. The fines entering the Combustor are composed of carbon, LASH and a very small amount of Desulfurizer sorbent.

The Fines Combustor air compressor supplies both quench air and combustion air to the burner. The Fines Combustor can be fired on natural gas when it is not burning filter fines.

5.2.7.9 Recycle Gas Compression (Section 900)

Section 900 provides for recompression and distribution of recycle gas to various users. Most of the product gas exiting the hot gas filter is routed either to the flare or to the gas turbine. A small portion of the gas is diverted through the recycle gas cooler to the following services:

- Most of the recycle gas is routed to the suction of the recycle gas compressor. This compressor supplies fluidizing and cooling gas to be lower Gasifier and fluidizing gas to the lower Desulfurizer.

- Some of the cooled recycle gas is routed through the recycle gas booster compressor trim cooler for additional cooling. This stream passes through a knock out drum and is routed to the suction of the recycle gas booster compressor. The first stage of the booster compressor supplies purges for the Gasifier and Desulfurizer instruments. It is also routed to the recycle gas receiver. Gas from the receiver is used for pressurization of the ash depressurization hopper and the filter fines depressurization hopper. The second stage of the booster compressor supplies the back-pulse medium to the hot gas filter back-pulse skid.

- A small percentage of the recycle gas is used for low pressure transport gas to convey collected particulate from the filter fines feed hopper to the Fines Combustor and from the ash feed hopper to the Sulfator.

5.2.8 Solid Waste Handling (Section 1100)

Cooled solid waste is pneumatically conveyed to the solids waste silo from the Gasifier Sulfator and Sulfator flue gas bag house filter. These solids are conveyed pneumatically with air from the solids transfer air dryer. Material from the fines collection package can also be pneumatically conveyed to the waste silo using nitrogen.

When necessary, the solids waste silo is emptied into trucks and the material is hauled to the local land fill. The silo is equipped with a bin discharger, discharge valve and a telescopic loading chute with a bag filter and fan to minimize dusting during the truck loading operation. The solid waste silo is sized for three days of storage (400 tons) to handle the solid waste production over the weekend without the need of the truck load-out operation.

5.2.9 Balance of Plant (Section 1200)

5.2.9.1 Raw Water System

The raw water system provides water to the demineralization package, which in turn provides boiler feedwater makeup to the Deaerator. Additionally, the raw water system provides water for the plant utility water system for miscellaneous users such as service wash stations. Well water from Well No. 4 is the source of water for the plant raw water system. Well water is pumped to the existing Unit 3 raw water tank and then pumped by the raw water pumps to the plant raw water system. Potable water for safety showers and eyewashes will be provided from Well No.4.

5.2.9.2 Boiler Feedwater Supply and Storage

Makeup boiler feedwater is demineralized by passing water from the raw water system through cation, anion and mixed bed exchangers. This system is designed to produce demineralized water for a boiler feed water make-up at a rate of 280 GPM.

Regeneration waste is stored in the neutralization tank, where the waste is mixed and neutralized before it is sent to the wastewater treatment system. Acid and caustic pumps are provided for neutralization. Demineralized water is stored in the demineralized water tank and pumped to the Deaerator by the demineralized water pumps.

A package of chemical dosing equipment is being provided for the conditioning treatment system of the boiler water.

5.2.9.3 Cooling Water System

The cooling tower is a three-celled counter current mechanical draft towers with two speed fans. The cooling tower is designed to maintain a maximum outlet temperature of 81°F with an ambient wet bulb temperature of 61°F. Make up water is pumped from the cooling pond by the cooling water make up pump.

The circulating water treatment system controls the addition of chemicals to the cooling water basin. The system is composed of the following 5 subsystems:

- Copper Corrosion Control System
- Scaling Control System
- pH Control System

- Algae Control System
- Conductivity Control System

5.2.9.4 Closed Loop Cooling Water System

A closed loop cooling water system is also provided for designated users. The water circulated in the closed loop system is essentially free of sediments and therefore it is less likely to leave deposits in downsteam equipment. The closed loop cooling water system never comes in direct contact with the water from the cooling tower.

5.2.9.5 Instrument and Plant Air System

A conventional plant and instrument air compression system is provided. Two air compressors, one operating, one spare, are provided for the system. A single air receiver provides adequate surge capacity. The air is dried to a -40°F dew point using an air drying desiccant system prior to branching off to plant and instrument air headers.

5.2.9.6 Flare System

A flare is provided to incinerate gases generated by the Gasifier during startup and upset conditions. The flare is a vertical freestanding system which uses natural gas for pilot gas, maintenance gas and assist gas. The flare system can experience many different gas loads during the course of operation. The anticipated operating modes are:

- Nitrogen Blanketed – The flare header is continuously purged with nitrogen, which is admitted at two locations. This purge nitrogen is never secured unless the Gasifier Island is tagged out for maintenance.

- Air – Large quantities of are introduced into the flare header during the course of normal plant start-up. The operating mode will continue until product gas is produced.

- Start-up Product Gas – Start product gas is defined as gas that is less than 60 Btu/scf. This gas is not expected to sustain combustion without the use of the flare assist gas ring.

- Normal Product Gas – Normal product gas is defined as gas that is more than 100 Btu/scf. This gas will sustain combustion without the use of the flare assist gas ring.

- PSV Relief Loads – The Gasifier Island has numerous pressure safety valves, which can discharge product gas into the flare header. Since the composition of product gas varies during start-up, the composition of the PSV discharge can also vary.

A Purgematic system is provided to detect and prevent negative pressure situations from developing in the flare header due to gas cooling. The Purgematic will sense the gas cooling as a pressure or temperature differential and initiate either a low or high rate nitrogen purge. Nitrogen for the low and high rate purges is supplied from the nitrogen purge drum.

5.2.9.7 Nitrogen System

Nitrogen is required during start-up and upset conditions when normal process gas is unavailable. Adequate nitrogen supplies are essential for the safe start-up and shutdown of the gasification facility.

During normal operations nitrogen is used to purge the flare header and inventory the flare purge drum. Other users include the coal and solids waste storage silos, and some of the Gasifier vessels and compressors.

The Nitrogen Package is a cryogenic air separation plant designed to yield a clean dry product of high purity (99.7%) nitrogen. The nitrogen plant supplies both 400 psig and 70 psig nitrogen primarily to the Gasifier Island.

A back-up system is provided which consists of a 55,000 gallon liquid nitrogen storage tank, a high pressure cryogenic nitrogen pump and four natural draft ambient vaporizers. The back-up system supplies nitrogen to the Gasifier during start-up and shutdown conditions when the base plant can't keep up with the demand.

5.2.9.8 Waste Water Treatment System

The waste water system is designed to clarify, soften and reduce the silica content of the circulating cooling water and neutralize demineralized regeneration waste.

A slipstream of circulating cooling water is sent to the equalization tank along with regeneration wastewater, gravity filter rejects and filtrate. The equalization tank is designed to provide a relatively constant loading and temperature to the downstream treatment equipment. Equalized water is withdrawn from the equalization tank and pumped to the Clarifier where caustic is added for pH adjustment. Magnesium sulfate and soda ash are also added to reduce hardness silica content. Polymers are added to promote the settling of calcium salts, magnesium salts and silica as sludge. The effluent from the Clarifier is direct to a pH adjustment tank prior to entering the gravity filter where acid is added to prevent precipitation. The pH adjusted effluent is then directed to the gravity filter where it is filter further before being returned to the cooling tower basin.

Clarifier sludge is sent to the sludge storage tank where it is thickened for volume reduction prior to being sent to the filter press for dewatering. Gravity filter rejects and filter press filtrate is returned to the equalization tank for reprocessing.

Blowdown from the evaporation tower is discharged to a six-acre evaporation pond. The pond is double lined and the system is designed to meet the requirements of the Nevada Division of Environmental Protection.

5.2.10 Equipment List

5.2.10.1 SECTION 100 Solids Receiving Storage and Crushing

	ITEM NO.	DESCRIPTON	EFD
Fans	B104	Gasifier Feed Dust Collection Fan	4143-326
	B105	Coal Receiving Exhaust Fan	4143-325
	B106A	Raw Coal Storage Exhaust Fan	4143-326
	B106B/C	Raw Coal Storage Exhaust Fan	4143-326
	B111	Crushing Station Dust Fan Filter	4143-325
	B112	Coal Silo Fan	4143-324
	B113	Sample Station Vent Fan	4143-321
	B115	Reclaim Tunnel Vent Fan	4143-322
	B116	Fresh Air Make-up Blower	4143-322
Bins	BN101A	Raw Coal Receiving Hopper	4143-321
	BN101B	Raw Coal Receiving Hopper	4143-321
	BN105	Coal Silo	4143-324
	BN106	Coal Silo	4143-324
	BN107	Limestone Silo	4143-324
	BN108	Emergency Reclaim Hopper	4143-322
	BN109	Emergency Surge Hopper	4143-323
	BN110	Coke Transporter Surge Hopper	4143-328
Bin Vibrators	BV102	Coal Silo Discharger	4143-324
	BV103	Coal Silo Discharger	4143-324
	BV104	Limestone Silo Discharger	4143-324
	BV106A/B	Coal Receiving Filter Vibrator	4143-325
	BV107A/B	Crusher Station Filter Vibrator	4143-325
	BV108A/B	Gasifier Feed Filter Vibrator	4143-326

	ITEM NO.	DESCRIPTON	EFD
Conveyors	CR102	Raw Coal Transfer Conveyor	4143-321
	CR105	Raw Coal Collecting Conveyor	4143-322
	CR110	Gasifier Elevating Conveyor	4143-324
	CR111	Filter Discharge Conveyor	4143-325
	CR114	Oversized Coal Conveyor	4143-323
	CR115	Sized Coal Conveyor	4143-323
	CR116	Sample Reject Bucket Conveyor	4143-321
	CR117	Emergency By-Pass Conveyor	4143-323
	CR118	Stacking Conveyor	4143-322
Diverters	DV105	Coal By-Pass Diverter	4143-323
	DV106	Coal Dust By-Pass Diverter	4143-325
Drums	D104	Limestone Transporter	4143-328
	D105	Transporter Air Receiver	4143-328
	D106	Coke Transporter	4143-328
Filters	F102	Coal Silo Dust Filter	4143-324
	F103	Coal Silo Exhaust Filter	4143-324
	F104	Limestone Silo Exhaust Filter	4143-324
	F105	Gasifier Feed Dust Filter	4143-326
	F106	Coal Receiving Dust Filter	4143-325
	F107A	Raw Coal Storage Dust Filter	4143-323
	F107B/C	Raw Coal Storage Dust Filter	4143-323
	F109	Crushing Station Dust Filter	4143-325
Feeders	FD101A	Raw Coal Receiving Feeder	4143-321
	FD101B	Raw Coal Receiving Feeder	4143-321
	FD106	Coal Silo Discharge Feeder	4143-324

	ITEM NO.	DESCRIPTON	EFD
	FD107	Coke Silo Discharge Feeder	4143-324
	FD108	Limestone Silo Discharge Feeder	4143-324
	FD109	Dust Collector Discharge Feeder	4143-326
	FD111	Receiving Filter Airlock Feeder	4143-325
	FD114	Coal Pile Discharge Feeder	4143-322
	FD115	Crushing Station Dust Filter Feeder	4143-325
	FD116	Primary Sample Feeder	4143-321
	FD117	Oversized Coal Feeder	4143-323
	FD116	Secondary Sample Feeder	4143-321
Misc	X100	Coal Storage Dome	4143-322
Packages	PG102	Stacker Reclaimer Package	4143-322
	PG103	Raw Coal Sampling Package	4143-321
Pumps	P101A	Unloading Station Sump Pump	4143-321
	P101B	Spare For P101A	4143-321
	P103A	Reclaim Tunnel Sump Pump	4143-322
	P103B	Spare For P103A	4143-321
Reclaimers	RL101	Coal Pile Reclaimer	4143-322
Sizing	SE101	Raw Coal Magnetic Separator	4143-322
Equipment	SE102	Gasifier Feed Magnetic Separator	4143-324
Size Reduction	SR102	Coal Crusher	4143-323
	SR103	Primary Sample Crusher	4143-321
Sampling	SS103	Primary Sampler	4143-321
	SS104	Secondary Sampler	4143-321
Scales	WS101	Raw Coal Receiving Scale	4143-324
	WS102	Truck Scale	

5.2.10.2 SECTION 200 Oxidant Compression

	ITEM NO.	DESCRIPTON	EFD
Compressors	C201	Booster Air Compressor	4141-126
Drums	D201	Knock Out Drum	4141-126
Exchangers	E201S1	Air Recuperator	4141-125
	E201S2	Air Recuperator	4141-125
	E202	Trim Cooler	4141-125
	E203S1	Air Precooler	4141-125
	E203S2	Air Precooler	4141-125
	E205S1	C201 Lube Oil Cooler	Vendor EFD
	E205S2	C201 Lube Oil Cooler	Vendor EFD
Pumps	P201	C201 Main Lube Oil Pump	Vendor EFD
	P202	C201 Auxiliary Lube Oil Pump	Vendor EFD

5.2.10.3 SECTION 300 Coal Gasification

	ITEM NO.	DESCRIPTON	EFD
Bins	BN301	Feed Surge Bin	4141-127
	BN302	Feed Pressurization Hopper	4141-127
	BN303	Feed Hopper	4141-127
Compressors	C301	Pressurization Air Compressor	4141-150
Drums	D301	Pressurization Air Receiver	4141-150
	D302	Aftercooler Moisture Separator	Vendor EFD
Filters	F301	Feed Hopper Vent Filter	4141-127
	F302	Feed Surge Bin Vent Filter	4141-127
Feeders	FD301	Coal Feeder	4141-127
	FD302	LASH Feeder	4141-143
Grinder	GD302	LASH Grinder	4141-143
Heaters	H301	Gasifier/Sulfator Start-up Heater	4141-149
Misc.	EL301	Personnel Elevator	
	FT301	Gasifier Feed Tube	4141-126
Vessels	R301	Gasifier	4141-126
Cyclones	S301	Gasifier Cyclone	4141-126
Exchangers	E301	C301 Aftercooler	Vendor EFD
	E302A/B	C301 Lube Oil Coolers	Vendor EFD
Package	PG301	Coal & Limestone Feed Package	4141-127
Pumps	P301	C301 Main Lube Oil Pump	Vendor EFD
	P302	C301 Auxiliary Lube Oil Pump	Vendor EFD
	P303	C301 Main Cooling Water Pump	Vendor EFD
	P304	C301 Auxiliary Cooling Water Pump	Vendor EFD

5.2.10.4 SECTION 400 Gas Stream Heat Recovery

	ITEM NO.	DESCRIPTON	EFD
Exchangers	E401	Product Gas Cooler	4141-129
	E402S1	Recycle Gas Cooler	4141-135
	E402S2	Recycle Gas Cooler	4141-135
	E403	Product Gas Trim Cooler	4141-135
Steam Generators	SG401	Gasifier Steam Drum	4141-147
Cyclones	S401	Desulfurizer Feed Cyclone	4141-130
Feeders	FD401	Fines Feeder	4141-130

5.2.10.5 SECTION 500 Gas Stream Particulate Removal

	ITEM NO.	DESCRIPTON	EFD
Bins	BN501	Ash Collection Hopper	4141-143
	BN502	Ash Depressurization Hopper	4141-143
	BN503	Filter Fines Collection Hopper	4141-141
	BN504	Filter Fines Depressurization Hopper	4141-141
	BN505	Limestone Feed Hopper	4141-145
	BN507	Filter Fines Feed Hopper	4141-141
	BN508	LASH Feed Hopper	4141-143
Drums	D501	Heat Transfer Fluid Storage Drum	4141-167
Exchangers	E501	Filter Fines Screw Cooler	4141-131
	E502	Heat Transfer Fluid Cooler	4141-167
Filters	F501	Hot Gas Filter	4141-131
	F502	Ash Vent Filter	4141-143
	F503	Filter Fines Vent Filter	4141-141
	F504	Limestone Feed Hopper Vent Filter	4141-145
	F505	Ash Collection Hopper Vent Filter	4141-143
Packages	PG501	Fine Heat Transfer Fluid System	4141-167
	PG502	Ash Collection System	4141-143
	PG503	Filter Fines Collection System	4141-141
	PG505	Back Pulse Skid Assembly	4141-159
	PG506	Back Pulse Skid Assembly	4141-159
Pumps	P501A	Heat Transfer Fluid Circulation Pump	4141-167
	P501B	Spare For P501A	4141-167
	P502	Circulation Pump For Heater	4141-167

5.2.10.6 SECTION 600 Desulfurization

	ITEM NO.	DESCRIPTON	EFD
Bins	BN601	Sulfator Solids Collection Hopper	4141-148
	BN603	Sorbent Storage Hopper	4141-134
	BN604	Sorbent Feed Hopper	4141-134
	BN607	Sulfator Solids Transfer Pot	4141-148
	BN608	Fines Transfer Pressure Pot	4141-148
	BN608A	Fines Surge Chute	4141-148
	BN610	Receiver Hopper	4141-134
Compressors	C601	Sulfator Air Compressor	4141-149
	C602	Fines Combustor Air Compressor	4141-144
	C610	Vacuum Blower	4141-134
Drums	D602	HRSG Steam Drum	4141-147
Dryer	DR601	Solids Transfer Air Dryer	4141-148
Exchangers	E602	Sulfator Solids Screw Cooler	4141-148
	E605	Primary Solids Cooler	4141-148
	E607	Regenerator Effluent Gas Cooler	4141-132
	E610	C601 Lube Oil Cooler	Vendor EFD
	E611	C601 Lube Oil Cooler	Vendor EFD
	E612	C602 Lube Oil Cooler	Vendor EFD
	E613	C602 Lube Oil Cooler	Vendor EFD
Filters	F602	Sulfator Flue Gas Bag House Filter	4141-147
	F605	Sorbent Pressurization Hopper Vent	4141-134
	F610	PG602 Guard Filter	4141-134
Heaters	H602	Fines Combustor	4141-146
	H608S1/S2	Sorbent Regeneration Air Heater	4141-133

	ITEM NO.	DESCRIPTON	EFD
Vessels	R602	Sulfator	4141-145
	R603	Transport Desulfurizer	4141-130
	R604	Transport Regenerator	4141-132
Cyclones	S601	Sulfator Cyclone	4141-145
	S603	Desulfurizer Cyclone	4141-130
	S604	Regenerator Cyclone	4141-132
Pumps	P601	C601 Main Lube Oil Pump	Vendor EFD
	P602	C601 Auxiliary Lube Oil Pump	Vendor EFD
	P603	C602 Main Lube Oil Pump	Vendor EFD
	P604	C602 Auxiliary Lube Oil Pump	Vendor EFD
Packages	PG601A	Sulfator Solids Transfer	4141-148
	PG601B	Fines Transfer	4141-148
	PG602	Sorbent Receiving and Unloading	4141-134

5.2.10.7 SECTION 700 Gas Turbine Generator

	ITEM NO.	DESCRIPTON	EFD
Gas Turbines	GT701	Gas Turbine Generator	4142-221

5.2.10.8 SECTION 800 Steam Turbine Generator and Heat Recovery Steam Generator

	ITEM NO.	DESCRIPTON	EFD
Deaerating Heater	DH801	Deaerator Heater	4142-226
Desuper-	DS801	Main Steam Attemperator	4142-222
Heaters	DS802	MP Steam Desuperheater	4142-227
	DS803	Pegging Steam Desuperheater	4142-227
	DS804	Sealing Steam Desuperheater	4142-234
Drums	D801	High Pressure Steam Drum	4142-222
	D802	Low Pressure Steam Drum	4142-223
	D803	Continuous Blowdown Drum	4142-225
	D804	Intermittent Blowdown Drum	4142-225
Exchangers	E801	Surface Condenser	4142-228
	E802	Gland Condenser	4142-234
Expansion	EJ801	E801 Expansion Joint	4142-228
Joints	EJ802	SG801 Expansion Joint	4142-222
	EJ803	SG801 Expansion Joint	4142-224
Hoists	HM801	Steam Turbine Generator Crane	Vendor
Pumps	P801A	Hotwell Condensate Pump	4142-228
	P801B	Spare for P801A	4142-228
	P802A	L.P. Boiler Feedwater Pump	4142-226
	P802B	Spare For P802A	4142-226
	P803A	H.P. Boiler Feedwater Pump	4142-226
	P803B	Spare For P803A	4142-228
	P804A	Vacuum Pump	4142-228
	P804B	Spare For P804A	4142-228

	ITEM NO.	DESCRIPTON	EFD
Stacks	ST801	Stack	4142-224
Steam Generators	SG801	Heat Recovery Steam Generator	4142-222
Steam Turbines	TG801	Steam Turbine Generator	4142-227

5.2.10.9 SECTION 900 Recycle Gas Compression

	ITEM NO.	DESCRIPTON	EFD
Compressors	C901	Recycle Gas Compressor	4141-135
	C902	Recycle Gas Booster Compressor	4141-139
Drums	D901	Recycle Gas Receiver	4141-139
	D902	C902 Knock Out Drum	4141-137
Exchangers	E901	C902 Trim Cooler	4141-137
	E902	C901 Lube Oil Cooler	Vendor
	E903	C902 Lube Oil Cooler	Vendor
	E904	C902 Lube Oil Cooler	Vendor
	E905	C902 Lube Oil Cooler	Vendor
Pumps	P901	C901 Main Lube Oil Pump	Vendor
	P902	C901 Auxiliary Lube Oil Pump	Vendor
	P903	C902 Main Lube Oil Pump	Vendor
	P904	C902 Auxiliary Lube Oil Pump	Vendor
	P905	C902 Main Cooling Water Pump	Vendor
	P906	C902 Auxiliary Cooling Water Pump	Vendor

5.2.10.10 SECTION 1000 Waste Water Treatment

	ITEM NO.	DESCRIPTON	EFD
Basins	X1000	Evaporation Pond	4143-364
Packages	PG1001	CT Sidestream Softening System	Vendor
	PG1002	Waste Evap. Tower Chemical Treat.	4143-363
Fans	B1001	Bag Dump Station Exhaust Fan	4143-357
Pumps	P1001A	Dirty Wastewater Pump	4143-339
	P1001B	Spare For P1001A	4143-339
	P1002A	Clean Wastewater Pump	4143-339
	P1002B	Spare For P1002A	4143-339
	P1004A	Blowdown Pump	4143-354
	P1004B	Spare For P1004B	4143-354
	P1005A	Sludge Pump	4143-353
	P1005B	Spare For P1005A	4143-353
	P1006A	Sludge Recirculation Pump	4143-352
	P1006B	Spare For P1006A	4143-352
	P1007A	Caustic Pump	4143-358
	P1007B	Spare For P1007A	4143-358
	P1008A	Soda Ash Pump	4143-357
	P1008B	Spare For P1008A	4143-357
	P1009A	Magnesium Sulfate Pump	4143-357
	P1009B	Spare For P1009A	4143-357
	P1010A	Acid Pump	4143-363
	P1010B	Spare For P1010A	4143-363

	ITEM NO.	DESCRIPTON	EFD
	P1011A	Scale Inhibitor Pump	4143-363
	P1011B	Spare For P1011A	4143-363
	P1012A	Brine Circulation Pump	4143-362
	P1012B	Brine Circulation Pump	4143-362
	P1012C	Spare For P1012A & B	4143-362
	P1013	Cationic Polymer Pump	4143-358
	P1014	Anionic Polymer Pump	4143-358
	P1016A	Waste Evaporation Circulating Water	4143-332
	P1016B	Spare For P1016A	4143-332
	P1017A	Flocculator Feed Pump	4143-356
	P1017B	Spare For P1017A	4143-356
	P1018A	Waste Water Treatment Sump Pump	4143-352
	P1018B	Spare For P1018A	4143-352
	P1019	pH Adjustment Pump	4143-352
	P1020A	Waste Evaporation Sump Pump	4143-363
	P1020B	Spare For P1020A	4143-363
Clarifiers	CL1001	Clarifier	4143-355
Cooling Tower	CT1001	Waste Evaporation Tower	4143-362
Exchangers	E1001A	Circulating Brine Exchanger	4143-359
	E1001B	Circulating Brine Exchanger	4143-359
Filters	F1001	Plate Filter Press	4143-353
	F1002	Gravity Filter	4143-354
	F1003	Soda Ash Silo Vent Filter	4143-357
	F1004A/B/C	Circulating Brine Filter	4143-359
	F1005A/B	Circulating Water Filter	4143-359

	ITEM NO.	DESCRIPTON	EFD
Feeder	FR1001	Soda Ash Feeder	4143-357
Drums	D1001	Caustic Drum	4143-358
	D1002	Acid Drum	4143-363
Tanks	TK1001	Equalization Tank	4143-356
	TK1002	Magnesium Sulfate Dissolving Tank	4143-357
	TK1003	Soda Ash Solution Tank	4143-357
	TK1004	Flocculator Tank	4143-355
	TK1005	Sludge Tank	4143-353
	TK1006	pH Adjustment Tank	4143-354
Misc.	S1001	Oily Water Separator	4143-364
	M1001	Flocculator Tank Mixer	4143-355
	M1002	Anionic Polymer Mixer	4143-358
	M1004	Soda Ash Mixer	4143-357
	M1005	Magnesium Sulfate Mixer	4143-357
	M1006	Static Mixer	4143-335
	M1007	Reaction Zone Mixer	4143-354
	M1008	Attenuation Zone Mixer	4143-354
	BN1001	Soda Ash Silo	4143-357
	BN1002	Magnesium Sulfate Bag Dump Station	4143-357
	BV1001	Soda Ash Vibrator	4143-357
	HM1001	Container Puller	Vendor
	AU1001	Circulating Brine Control System	4143-363

5.2.10.11 SECTION 1100 Solid Waste Handling

	ITEM NO.	DESCRIPTON	EFD
Fans	B1102	Load-Out Exhaust Fan	4143-327
Bins	BN1101	Solid Waste Silo	4143-327
Bin VIBRATORS	BV1101	Solid Waste Discharger	4143-327
	BV1102	Load-Out Chute Vibrator	4143-327
CHUTES	CH1101	Solid Waste Loading Chute	4143-327
Filters	F1101	Silo Vent Filter	4143-327
	F1102	Load-Out Filter	4143-327
Packages	PG1101	Solid Waste Load-Out Package	4143-327
	XV1101	Load-Out Slide Gate	4143-327

5.2.10.12 SECTION 1200 Balance of Plant

	ITEM NO.	DESCRIPTON	EFD
Fans	B1202A	Degasifier Blower	4143-327
	B1202B	Spare For B1202A	4143-327
Compressors	C1201A	Instrument and Plant Air Compressor	4143-334
	C1201B	Spare For C1201A	4143-334
	C1203	Nitrogen Air Compressor (CP11)	4143-341
	C1204	Nitrogen Booster Compressor (CP53)	4143-341
Cooling Tower	CT1201	Cooling Tower	4143-333
Drums	D1201	Acid Storage Drum	4143-338
	D1202	Caustic Storage Drum	4143-338
	D1203A	Cation Unit	4143-337
	D1203B	Cation Unit	4143-337
	D1204A	Anion Unit	4143-336
	D1204B	Anion Unit	4143-336
	D1207	Instrument and Plant Air Receiver	4143-334
	D1209	Acid Drum	4143-342
	D1211A	Mixed Bed Unit	4143-336
	D1211B	Mixed Bed Unit	4143-336
	D1213	Amine Measuring Pot	4143-331
	D1214	Oxygen Scavenger Measuring Pot	4143-331
Dryers	DR1201A	Instrument Plant Air Dryer	4143-334
	DR1201B	Spare For DR1201A	4143-334

	ITEM NO.	DESCRIPTON	EFD
Exchangers	E1201A	Caustic Water Heater	4143-338
	E1201B	Spare For E1201A	4143-338
	E1203A/B	Nitrogen Vaporizer Skids (HE-812A/B)	4143-341
	E1204	Caustic Storage Drum Heater	4143-338
Feeders	FD1201A	Biocide Feeder	4143-342
	FD1201B	Biocide Feeder	4143-342
Filters	F1202A	Circulating Water Filter	4143-345
	F1202B	Circulating Water Filter	4143-345
	F1203A/B	Fuel Gas Filters	4143-349
Flares	FL1201	Flare	4143-340
Mixers	M1201A	Phosphate Tank Mixer	4143-331
	M1201B	Phosphate Tank Mixer	4143-331
	M1203	Amine Dilution Mixer	4143-331
	M1204	Oxygen Scavenger Mixer	4143-331
Pumps	P1201	Cooling Tower Make-Up Water Pump	4143-344
	P1202A	Raw Water Pump	4143-343
	P1202B	Spare For P1202A	4143-343
	P1203A	Acid Regeneration Pump	4143-338
	P1203B	Spare For P1203A & P1205	4143-338
	P1204A	Caustic Regeneration Pump	4143-338
	P1204B	Spare For P1204A & P1206	4143-338
	P1205	Acid Neutralization Pump	4143-338
	P1206	Caustic Neutralization Pump	4143-338
	P1208A	Demineralized Water Pump	4143-335

ITEM NO.	DESCRIPTON	EFD
P1208B	Spare For P1208A	4143-335
P1209A	Circulating Water Pump	4143-333
P1209B	Circulating Water Pump	4143-333
P1209C	Spare For Pumps P1209A/B	4143-333
P1210A	Oxygen scavenger Pump	4143-331
P1210B	Spare For P1210A	4143-331
P1211A	Phosphate Pump	4143-331
P1211B	Phosphate Pump	4143-331
P1211C	Spare For P1211A/B/D	4143-331
P1211D	Phosphate Pump	4143-331
P1212A	L.P. Phosphate Pump	4143-331
P1212B	Spare For P1212A	4143-331
P1213A	Amine Pump	4143-331
P1213B	Spare For P1213A	4143-331
P1215A	Acid Pumps	4143-342
P1215B	Spare For P1215A & P1019	4143-342
P1217A	Booster Pump	4143-337
P1217B	Booster Pump	4143-337
P1217C	Spare For P1217A/B	4143-337
P1218 (P811)	Liquid Nitrogen Transfer Pump	4143-341
P1219A	Circulating Water Booster Pump	4143-345
P1219B	Spare For P1219A	4143-345
P1221A	Regeneration Waste Water Pump	4143-335
P1221B	Spare For P1221A	4143-335

	ITEM NO.	DESCRIPTON	EFD
`	P1223A	Copper Corrosion Inhibitor Pump	4143-342
	P1223B	Spare for P1223A	4143-342
	P1224	Amine Transfer Pump	4143-331
	P1225	Oxygen Scavenger Transfer Pump	4143-331
	P1226A	Scale Inhibitor Pump	4143-342
	P1226B	Spare For P1226A	4143-342
Packages	AU1201	Circulating Water Control System	4143-342
	PG1201	Demineralization Package	4143-336
	PG1202	Circulating Water Treatment Package	4143-342
	PG1203	Boiler Water Treatment Package	4143-331
	PG1205	Nitrogen Package	4143-341
	PG1208	Drinking Water Pressurization Package	4143-351
	PG1209	Pond Water Pressurization Package	4143-351
Tanks	TK1201	Demineralized Water Tank	4143-335
	TK1202	Neutralization Tank	4143-335
	TK1203A	Phosphate Tank	4143-331
	TK1203B	Phosphate Tank	4143-331
	TK1204	Amine Dilution Tank	4143-331
	TK1205 (T81)	HP Liquid Nitrogen Storage Tank	4143-341
	TK1207	Oxygen Scavenger Dilution Tank	4143-331
Towers	T1201	Degasifier	4143-337
	T1202 (C25)	Nitrogen Package Cold Box	4143-341

5.3 Plant Cost Data

Piñon Pine

Total construction/improvement costs	Combined Cycle	Gasifier	Hot Gas Clean up	Total
Vessels	$268,241	$0	$0	$268,241
Heat Transfer	$1,178,709	$0	$0	$1,178,709
Mechancial	$36,297,708	$5,625,912	$0	$41,923,620
Miscellaneous	$1,986,006	$146,618	$0	$2,132,624
Civil	$0	$1,919,081	$0	$1,919,081
Sub Contractors Materials & Construction	$2,320,244	$2,652,588	$0	$4,972,832
Civil	$1,473,208	$3,478,999	$698,891	$5,651,098
Piping	$2,932,907	$3,916,426	$936,276	$7,785,609
Instrumentation	$1,692,569	$1,115,405	$309,054	$3,117,028
Electrical	$3,139,768	$1,052,851	$274,298	$4,466,917
Bulk Materials	$0	$2,515,254	$933,962	$3,449,216
Kellogg Class B Furnaces	$0	$2,241,914	$0	$2,241,914
Class C Exchangers	$0	$647,703	$1,159,554	$1,807,257
Class D Converters	$0	$2,540,373	$1,179,182	$3,719,555
Class F Drums	$0	$187,939	$173,786	$361,725
Class J Compressors	$0	$2,494,764	$16,622	$2,511,386
Class L Special Equipment	$0	$0	$3,087,331	$3,087,331
Class V Material Handling	$0	$3,155,549	$341,879	$3,497,428
Spares	$0	$1,036,415	$548,030	$1,584,445
Freight	$0	$639,868	$293,324	$933,192
Direct Contracts	$0	$1,251,687	$0	$1,251,687
SPPC	$18,689,158	$27,009,013	$9,198,542	$54,896,713
Office Labor	$14,831,027	$18,790,599	$6,616,447	$40,238,073
Office Non Labor	$2,784,687	$3,194,501	$1,089,365	$7,068,553
Sub-Contractors	$23,514,301	$29,113,673	$7,590,403	$60,218,377
Direct Hire	$1,274,029	$4,174,066	$1,088,246	$6,536,341
Construction Management	$11,503,439	$13,910,649	$3,530,780	$28,944,868
Miscellaneous	$1,838,015	$1,497,801	$439,072	$3,774,888
Process Improvements	$2,722,030	$2,908,167	$855,458	$6,485,655
Total	$125,724,016	$134,309,648	$39,505,044	$306,024,363
Less DOE Funds				($135,441,364)
Net Construction/Improvement				$170,582,999

Note: The above numbers are actual dollars spent including AFUDC (Allowance for Funds used during Construction) and Capital Interest.

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REV. 3

SIERRA PACIFIC POWER COMPANY

TRACY 4 - PIÑON PROJECT

RENO, NEVADA

HEAT AND MATERIAL BALANCE - BASE CASE

THE M. W. KELLOGG COMPANY

JOB 7514

DATE	REV #	PREP'D	CHECKED	CTE APPR
27 JUL 93	0	FC	GKM	GBH
11 APR 94	1	SN	GKM	GBH
08 JUN 94	2	SN	GKM	GBH
09 DEC 94	3	SN	JOD / [illegible]	GH

HEAT AND MATERIAL BALANCE - BASE CASE
UNDRIED SUFCO COAL WITH TRANSPORT DESULFURIZER

IDENTIFICATION	Molecular Weight	1 Prepared Coal Feedstock		2 Limestone Feedstock		3 Ash Withdrawal From Gasifier		4 Coal Transport Air	
		Wt%	Lb/Hr	Wt%	Lb/Hr	Wt%	Lb/Hr	Vol%	Lb/Hr
GASES:									
Carbon Monoxide	28.01							0.00	0
Hydrogen	2.02							0.00	0
Carbon Dioxide	44.01							0.00	0
Methane	16.04							0.00	0
Nitrogen	28.01							78.00	14,645
Argon	39.95							0.90	240
Oxygen	32.00							20.82	4,466
Ammonia	17.03							0.00	0
Hydrogen Sulfide	34.08							0.00	0
Carbonyl Sulfide	60.08							0.00	0
Sulfur Dioxide	64.06							0.00	0
Water Vapor	18.02							0.29	35
Hydrogen Chloride	36.46							0.00	0
TOTAL GASES								100.00	19,385
Gas Flow, Lb Moles/Hr									670.3
Molecular Weight, Gases									28.92
Gas Volume, ACFM									193.0
Gas Volume, SCFM									4,238
LIQUIDS:									
Water	18.02								
SOLIDS:									
Carbon	12.01	64.24	47,249			27.19	1,685		
Hydrogen	1.01	4.33	3,187			0.07	5		
Oxygen	16.00	10.94	8,043			0.35	22		
Nitrogen	14.01	1.08	798			0.22	14		
Sulfur	32.06	0.41	298			0.17	10		
Chlorides	35.45	0.00	0			0.00	0		
Ash		9.00	6,620			72.00	4,463		
Moisture	18.02	10.00	7,355			0.00	0		
TOTAL SOLIDS		100.00	73,550			100.00	6,199		
SORBENT:									
CaO	56.08			0.00	0	74.50	1,305		
CaCO3	100.09			90.04	3,720	0.00	0		
CaS	72.14			0.00	0	12.44	218		
CaSO4	136.14			0.00	0	0.00	0		
MgO	40.31			0.00	0	3.26	57		
MgCO3	84.32			4.09	169	0.00	0		
Inerts				5.87	242	9.79	172		
TOTAL SORBENT				100.00	4,131	100.00	1,752		
TOTAL FLOW, Lb/Hr			73,550		4,131		7,951		19,385
HEATING VALUE:									
Gas LHV, Btu/SCF									
Gaseous Fuel LHV, MMBtu/hr									
TEMPERATURE, F			50		50		500		120
PRESSURE, PSIA			13		13		310	3	360

Pinon Pine Power Project
Sierra Pacific Power Company
Reno, Nevada

M. W. KELLOGG

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HEAT AND MATERIAL BALANCE - BASE CASE
UNDRIED SUFCO COAL WITH TRANSPORT DESULFURIZER

IDENTIFICATION	Molecular Weight	5 Process Air To Gasifier		6 Product Gas From Gasifier		7 Product Gas From Cyclone		8 Total Air From Gas Turbine (3)	
		Vol%	Lb/Hr	Vol%	Lb/Hr	Vol%	Lb/Hr	Vol%	Lb/Hr
GASES:									
Carbon Monoxide	28.01	0.00	0	23.89	82,996	23.89	82,996	0.00	0
Hydrogen	2.02	0.00	0	14.57	3,643	14.57	3,643	0.00	0
Carbon Dioxide	44.01	0.00	0	5.44	29,708	5.44	29,708	0.00	0
Methane	16.04	0.00	0	1.35	2,679	1.35	2,679	0.00	0
Nitrogen	28.01	78.00	145,063	48.65	169,052	48.65	169,052	78.00	164,042
Argon	39.95	0.90	2,379	0.56	2,760	0.56	2,760	0.90	2,690
Oxygen	32.00	20.82	44,235	0.00	0	0.00	0	20.82	50,022
Ammonia	17.03	0.00	0	0.02	40	0.02	40	0.00	0
Hydrogen Sulfide	34.08	0.00	0	0.03	127	0.03	127	0.00	0
Carbonyl Sulfide	60.08	0.00	0	0.00	30	0.00	30	0.00	0
Sulfur Dioxide	64.06	0.00	0	0.00	0	0.00	0	0.00	0
Water Vapor	18.02	0.29	342	5.50	12,284	5.50	12,284	0.29	387
Hydrogen Chloride	36.46	0.00	0	0.00	0	0.00	0	0.00	0
TOTAL GASES		100.00	192,019	100.00	303,319	100.00	303,319	100.00	217,141
Gas Flow, Lb Moles/Hr			6639.3		12404.2		12404.2		7,508.0
Molecular Weight, Gases			28.92		24.45		24.45		28.92
Gas Volume, ACFM			3660.0		16992.1		17166.6		10067.6
Gas Volume, SCFM			41,977		78,425		78,425		47,469
LIQUIDS:									
Water	18.02								
				Wt%		Wt%			
SOLIDS:									
Carbon	12.01			54.20	45,794	54.20	2,656		
Hydrogen	1.01			0.33	275	0.33	16		
Oxygen	16.00			0.70	591	0.70	34		
Nitrogen	14.01			0.41	345	0.41	20		
Sulfur	32.06			0.36	308	0.36	18		
Chlorides -	35.45			0.00	0	0.00	0		
Ash				44.00	37,174	44.00	2,156		
Moisture	18.02			0.00	0	0.00	0		
TOTAL SOLIDS				100.00	84,487	100.00	4,900		
SORBENT:									
CaO	56.08			74.50	26,976	74.50	539		
CaCO3	100.09			0.00	0	0.00	0		
CaS	72.14			12.44	4,505	12.44	90		
CaSO4	136.14			0.00	0	0.00	0		
MgO	40.31			3.26	1,181	3.26	24		
MgCO3	84.32			0.00	0	0.00	0		
Inerts				9.79	3,546	9.79	71		
TOTAL SORBENT				100.00	36,209	100.00	724		
TOTAL FLOW, Lb/Hr			192,019		424,015		308,943		217,141
HEATING VALUE:									
Gas LHV, Btu/SCF					129		129		
Gaseous Fuel LHV, MMBtu/hr					607.4		607.4		
TEMPERATURE, F			650		1,800		1,800 (3)		752
PRESSURE, PSIA			360		295		292		162

HEAT AND MATERIAL BALANCE - BASE CASE
UNDRIED SUFCO COAL WITH TRANSPORT DESULFURIZER

IDENTIFICATION	Molecular Weight	9 Recycle Gas To Grid		10 Steam to Gasifier		11 Recycle Gas to Annulus		12 Product Gas From Desulfurizer	
		Vol%	Lb/Hr	Vol%	Lb/Hr	Vol%	Lb/Hr	Vol%	Lb/Hr
GASES:									
Carbon Monoxide	28.01	23.91	736			23.91	2,864	23.89	86,604
Hydrogen	2.02	14.58	32			14.58	126	14.57	3,802
Carbon Dioxide	44.01	5.45	264			5.45	1,026	5.45	31,022
Methane	16.04	1.35	24			1.35	92	1.35	2,795
Nitrogen	28.01	48.70	1,500			48.70	5,833	48.66	176,400
Argon	39.95	0.56	24			0.56	95	0.56	2,880
Oxygen	32.00	0.00	0			0.00	0	0.00	0
Ammonia	17.03	0.02	0			0.02	1	0.02	42
Hydrogen Sulfide	34.08	0.00	0			0.00	0	0.00	9
Carbonyl Sulfide	60.08	0.00	0			0.00	0	0.00	0
Sulfur Dioxide	64.06	0.00	0			0.00	0	0.00	0
Water Vapor	18.02	5.43	108	100.00	12,356	5.43	419	5.51	12,836
Hydrogen Chloride	36.46	0.00	0			0.00	0	0.00	0
TOTAL GASES		100.00	2,689	100.00	12,356	100.00	10,455	100.00	316,389
Gas Flow, Lb Moles/Hr			109.9		685.9		427.6		12,941
Molecular Weight, Gases			24.45		18.02		24.45		24.45
Gas Volume, ACFM			47.5		312.8		184.8		12,462
Gas Volume, SCFM			695		4,336		2,703		81,819
LIQUIDS:									
Water	18.02								
SOLIDS:								Wt%	
Carbon	12.01							54.20	2,531
Hydrogen	1.01							0.33	15
Oxygen	16.00							0.70	33
Nitrogen	14.01							0.41	19
Sulfur	32.06							0.36	17
Chlorides -	35.45							0.00	0
Ash								44.00	2,054
Moisture	18.02							0.00	0
TOTAL SOLIDS								100.00	4,669
SORBENT:									
CaO	56.08							74.50	514
CaCO3	100.09							0.00	0
CaS	72.14							12.44	86
CaSO4	136.14							0.00	0
MgO	40.31							3.26	23
MgCO3	84.32							0.00	0
Inerts								9.79	68
TOTAL SORBENT								100.00	690
TOTAL FLOW, Lb/Hr			2,689		12,356		10,455		321,748
HEATING VALUE:									
Gas LHV, Btu/SCF			129		-		129		129
Gaseous Fuel LHV, MMBtu/hr			5.4				20.9		632.7
TEMPERATURE, F			350		700		350		1,013
PRESSURE, PSIA			335		433		335		274

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UNDRIED SUFCO COAL WITH TRANSPORT DESULFURIZER

IDENTIFICATION	Molecular Weight	13 (Rev. 3) Condensate From Recycle Gas		14 (Note 1) (Rev. 3) Blowback Gas to Filter		15 (Rev. 3) Recycle Gas To RG Booster Comp.		16 (Note 1) (Rev. 3) Pressurization Recycle Gas	
		Wt%	Lb/Hr	Vol%	Lb/Hr	Vol%	Lb/Hr	Vol%	Lb/Hr
GASES:									
Carbon Monoxide	28.01			25.21	1266	25.21	1,444	25.21	177
Hydrogen	2.02			15.37	56	15.37	63	15.37	8
Carbon Dioxide	44.01			5.75	454	5.75	517	5.75	63
Methane	16.04			1.42	41	1.42	47	1.42	6
Nitrogen	28.01			51.34	2579	51.34	2,940	51.34	361
Argon	39.95			0.59	42	0.59	48	0.59	6
Oxygen	32.00			0.00	0	0.00	0	0.00	0
Ammonia	17.03			0.02	1	0.02	1	0.02	0
Hydrogen Sulfide	34.08			0.00	0	0.00	0	0.00	0
Carbonyl Sulfide	60.08			0.00	0	0.00	0	0.00	0
Sulfur Dioxide	64.06			0.00	0	0.00	0	0.00	0
Water Vapor	18.02			0.30	10	0.30	11	0.30	1
Hydrogen Chloride	36.46			0.00	0	0.00	0	0.00	0
TOTAL GASES				100.00	4,448	100.00	5,071	100.00	622
Gas Flow, Lb Moles/Hr					179.3		204.4		25.1
Molecular Weight, Gases					24.80		24.80		24.80
Gas Volume, ACFM					18.4		80.5		5.5
Gas Volume, SCFM					1,134		1,293		159
LIQUIDS:									
Water	18.02	100.00	200						
SOLIDS:									
Carbon	12.01								
Hydrogen	1.01								
Oxygen	16.00								
Nitrogen	14.01								
Sulfur	32.06								
Chlorides	35.45								
Ash									
Moisture	18.02								
TOTAL SOLIDS									
SORBENT:									
CaO	56.08								
CaCO3	100.09								
CaS	72.14								
CaSO4	136.14								
MgO	40.31								
MgCO3	84.32								
Inerts									
TOTAL SORBENT									
TOTAL FLOW, Lb/Hr			200		4,448		5,071		622
HEATING VALUE:									
Gas LHV, Btu/SCF					136		136		136
Gaseous Fuel LHV, MMBtu/hr					9.3		10.5		1.3
TEMPERATURE, F			90		230		90		230
PRESSURE, PSIA			250		1,200		250		565

Note 1: Streams 14 and 16 are time averaged flow rates.
Stream 14 also includes 1200 lb/hr instrument purge flow.

HEAT AND MATERIAL BALANCE - BASE CASE
UNDRIED SUFCO COAL WITH TRANSPORT DESULFURIZER

IDENTIFICATION	Molecular Weight	17 (3) Sorbent Regeneration Gas To Sulfator		18 (3) Cooled Recycle Gas		19 (Note 1) Pressurization Air		20 (3) Hot Recycle Gas	
		Vol%	Lb/Hr	Vol%	Lb/Hr	Vol%	Lb/Hr	Vol%	Lb/Hr
GASES:									
Carbon Monoxide	28.01	0.00	0	23.91	10,566	0.00	0	23.91	10,565
Hydrogen	2.02	0.00	0	14.58	464	0.00	0	14.58	464
Carbon Dioxide	44.01	0.00	0	5.45	3,785	0.00	0	5.45	3,785
Methane	16.04	0.00	0	1.35	341	0.00	0	1.35	341
Nitrogen	28.01	83.81	626	48.70	21,521	78.00	2,970	48.70	21,520
Argon	39.95	0.96	10	0.56	351	0.90	49	0.56	351
Oxygen	32.00	0.00	0	0.00	0	20.82	906	0.00	0
Ammonia	17.03	0.00	0	0.02	5	0.00	0	0.02	5
Hydrogen Sulfide	34.08	0.00	0	0.00	1	0.00	0	0.00	1
Carbonyl Sulfide	60.08	0.00	0	0.00	0	0.00	0	0.00	0
Sulfur Dioxide	64.06	14.91	255	0.00	0	0.00	0	0.00	0
Water Vapor	18.02	0.31	1	5.43	1,545	0.29	7	5.43	1,545
Hydrogen Chloride	36.46	0.00	0	0.00	0	0.00	0	0.00	0
TOTAL GASES		99.99	892	100.00	38,578	100.00	3,932	100.00	38,577
Gas Flow, Lb Moles/Hr			26.6		1,577.6		136.0		1,577.6
Molecular Weight, Gases			33.47		24.45		28.92		24.45
Gas Volume, ACFM			219.6		801.7		23.5		1567.0
Gas Volume, SCFM			168		9,974		860		9,974
LIQUIDS:									
Water	18.02								
SOLIDS:									
Carbon	12.01								
Hydrogen	1.01								
Oxygen	16.00								
Nitrogen	14.01								
Sulfur	32.06								
Chlorides -	35.45								
Ash									
Moisture	18.02								
TOTAL SOLIDS									
SORBENT:									
CaO	56.08								
CaCO3	100.09								
CaS	72.14								
CaSO4	136.14								
MgO	40.31								
MgCO3	84.32								
Inerts									
TOTAL SORBENT									
TOTAL FLOW, Lb/Hr			892		38,578		3,932		38,577
HEATING VALUE:									
Gas LHV, Btu/SCF					129				129
Gaseous Fuel LHV, MMBtu/hr					77.2				77.2
TEMPERATURE, F			600		270		120		1,000
PRESSURE, PSIA			23		257		600		263

Note 1: Stream 19 is a time averaged flow rate.

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HEAT AND MATERIAL BALANCE - BASE CASE
UNDRIED SUFCO COAL WITH TRANSPORT DESULFURIZER

IDENTIFICATION	Molecular Weight	21 Limestone To Sulfator		22 (3) Sulfator System Flue Gas To Vent		23 Solids From Sulfator		24 (Note 1) Total Solids to Disposal	
		Wt%	Lb/Hr	Vol%	Lb/Hr	Wt%	Lb/Hr	Wt%	Lb/Hr
GASES:									
Carbon Monoxide	28.01			0.00	0				
Hydrogen	2.02			0.00	0				
Carbon Dioxide	44.01			9.65	18,033				
Methane	16.04			0.00	0				
Nitrogen	28.01			77.23	91,879				
Argon	39.95			0.89	1,507				
Oxygen	32.00			10.33	14,044				
Ammonia	17.03			0.00	1				
Hydrogen Sulfide	34.08			0.00	0				
Carbonyl Sulfide	60.08			0.00	0				
Sulfur Dioxide	64.06			0.01	37				
Water Vapor	18.02			1.88	1,438				
Hydrogen Chloride	36.46			0.00	0				
TOTAL GASES				100.00	126,939				
Gas Flow, Lb Moles/Hr					4,246.7				
Molecular Weight, Gases					29.89				
Gas Volume, ACFM					47301.8				
Gas Volume, SCFM					26,849				
LIQUIDS:									
Water	18.02								
SOLIDS:									
Carbon	12.01					0.74	34	1.28	87
Hydrogen	1.01					0.00	0	0.00	0
Oxygen	16.00					0.48	22	0.82	56
Nitrogen	14.01					0.30	14	0.50	34
Sulfur	32.06					0.00	0	0.01	0
Chlorides -	35.45					0.00	0	0.00	0
Ash						98.47	4,463	97.40	6,619
Moisture	18.02					0.00	0	0.00	0
TOTAL SOLIDS						100.00	4,533	100.00	6,796
SORBENT:									
CaO	56.08	0.00	0			52.94	1,305	57.84	1,844
CaCO3	100.09	90.04	426			0.00	0	0.00	0
CaS	72.14	0.00	0			4.42	109	6.24	199
CaSO4	136.14	0.00	0			31.85	785	24.62	785
MgO	40.31	0.00	0			2.69	66	2.82	90
MgCO3	84.32	4.09	19			0.00	0	0.00	0
Inerts		5.87	28			8.09	199	8.47	270
TOTAL SORBENT		100.00	473			100.00	2,465	100.00	3,189
TOTAL FLOW, Lb/Hr			473		126,939		6,998		9,985
HEATING VALUE:									
Gas LHV, Btu/SCF									
Gaseous Fuel LHV, MMBtu/hr									
TEMPERATURE, F			50		350		1,600		(3) 210
PRESSURE, PSIA			20		13		17		13

Note 1: Temperature of stream 24 is calculated by blending stream 64 with the cooled sulfator solids stream.

HEAT AND MATERIAL BALANCE - BASE CASE
UNDRIED SUFCO COAL WITH TRANSPORT DESULFURIZER

IDENTIFICATION	Molecular Weight	25 Cyclone Fines to Gasifier		26 △3 Desulfurized Product Gas From Hot Gas Filter		27 △3 Hot Regen. Air to Transp. Regenerator		28 △3 Regeneration Air to Transp. Regenerator	
		Wt%	Lb/Hr	Vol%	Lb/Hr	Vol%	Lb/Hr	Vol%	Lb/Hr
GASES:									
Carbon Monoxide	28.01			23.91	88,418	0.00	0	0.00	0
Hydrogen	2.02			14.58	3,881	0.00	0	0.00	0
Carbon Dioxide	44.01			5.45	31,672	0.00	0	0.00	0
Methane	16.04			1.35	2,853	0.00	0	0.00	0
Nitrogen	28.01			48.70	180,095	78.00	626	78.00	626
Argon	39.95			0.56	2,940	0.90	10	0.90	10
Oxygen	32.00			0.00	0	20.82	191	20.82	191
Ammonia	17.03			0.02	43	0.00	0	0.00	0
Hydrogen Sulfide	34.08			0.00	9	0.00	0	0.00	0
Carbonyl Sulfide	60.08			0.00	0	0.00	0	0.00	0
Sulfur Dioxide	64.06			0.00	0	0.00	0	0.00	0
Water Vapor	18.02			5.43	12,926	0.29	1	0.29	1
Hydrogen Chloride	36.46			0.00	0	0.00	0	0.00	0
TOTAL GASES				100.00	322,837	100.00	828	100.00	828
Gas Flow, Lb Moles/Hr					13,202.1		28.6		28.6
Molecular Weight, Gases					24.45		28.92		28.92
Gas Volume, ACFM					13113.8		23.5		15.8
Gas Volume, SCFM					83,469		181		181
LIQUIDS:									
Water	18.02								
SOLIDS:									
Carbon	12.01	54.20	43,138						
Hydrogen	1.01	0.33	259						
Oxygen	16.00	0.70	557						
Nitrogen	14.01	0.41	325						
Sulfur	32.06	0.36	290						
Chlorides -	35.45	0.00	0						
Ash		44.00	35,018						
Moisture	18.02	0.00	0						
TOTAL SOLIDS		100.00	79,587						
SORBENT:									
CaO	56.08	74.50	26,437						
CaCO3	100.09	0.00	0						
CaS	72.14	12.44	4,415						
CaSO4	136.14	0.00	0						
MgO	40.31	3.26	1,158						
MgCO3	84.32	0.00	0						
Inerts		9.79	3,475						
TOTAL SORBENT		100.00	35,485						
TOTAL FLOW, Lb/Hr			115,072		322,837		828		828
HEATING VALUE:									
Gas LHV, Btu/SCF					129				
Gaseous Fuel LHV, MMBtu/hr					646.1				
TEMPERATURE, F		△3	1,790		1,000		1,100		650
PRESSURE, PSIA			292		263		340		360

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HEAT AND MATERIAL BALANCE - BASE CASE
UNDRIED SUFCO COAL WITH TRANSPORT DESULFURIZER

IDENTIFICATION	Molecular Weight	29 △3 Desulf. Feed Cyc. Fines Transport Gas		30 Ash Transport Gas		31 Fines Transport Gas		32 △3 Product Gas to Gas Turbine	
		Vol%	Lb/Hr	Vol%	Lb/Hr	Vol%	Lb/Hr	Vol%	Lb/Hr
GASES:									
Carbon Monoxide	28.01	23.91	82	23.91	436	23.91	308	23.91	77,852
Hydrogen	2.02	14.58	4	14.58	19	14.58	14	14.58	3,417
Carbon Dioxide	44.01	5.45	29	5.45	156	5.45	110	5.45	27,887
Methane	16.04	1.35	3	1.35	14	1.35	10	1.35	2,512
Nitrogen	28.01	48.70	167	48.70	887	48.70	627	48.70	158,575
Argon	39.95	0.56	3	0.56	14	0.56	10	0.56	2,589
Oxygen	32.00	0.00	0	0.00	0	0.00	0	0.00	0
Ammonia	17.03	0.02	0	0.02	0	0.02	0	0.02	38
Hydrogen Sulfide	34.08	0.00	0	0.00	0	0.00	0	0.00	8
Carbonyl Sulfide	60.08	0.00	0	0.00	0	0.00	0	0.00	0
Sulfur Dioxide	64.06	0.00	0	0.00	0	0.00	0	0.00	0
Water Vapor	18.02	5.43	12	5.43	64	5.43	45	5.43	11,381
Hydrogen Chloride	36.46	0.00	0	0.00	0	0.00	0	0.00	0
TOTAL GASES		100.00	300	100.00	1,590	100.00	1,125	100.00	284,260
Gas Flow, Lb Moles/Hr			12.3		65.0		46.0		11,624.5
Molecular Weight, Gases			24.45		24.45		24.45		24.45
Gas Volume, ACFM			5.3		33.0		23.4		11546.8
Gas Volume, SCFM			78		411		291		73,495
LIQUIDS:									
Water	18.02								
SOLIDS:									
Carbon	12.01								
Hydrogen	1.01								
Oxygen	16.00								
Nitrogen	14.01								
Sulfur	32.06								
Chlorides -	35.45								
Ash									
Moisture	18.02								
TOTAL SOLIDS									
SORBENT:									
CaO	56.08								
CaCO3	100.09								
CaS	72.14								
CaSO4	136.14								
MgO	40.31								
MgCO3	84.32								
Inerts									
TOTAL SORBENT									
TOTAL FLOW, Lb/Hr			300		1,590		1,125		284,260
HEATING VALUE:									
Gas LHV, Btu/SCF			129		129		129		129
Gaseous Fuel LHV, MMBtu/hr			0.6		3.2		2.3		568.9
TEMPERATURE, F			350		270		270		1,000
PRESSURE, PSIA			335		257 △3		257 △3		263

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HEAT AND MATERIAL BALANCE - BASE CASE
UNDRIED SUFCO COAL WITH TRANSPORT DESULFURIZER

IDENTIFICATION	Molecular Weight	33 Low Pressure Transport Gas		34 △3 High Pressure Transport Gas		35 △3 BFW Blowdown From Sulfator Steam Drum		36 △3 Desulf. Feed Cyc. Fines to HGF	
		Vol%	Lb/Hr	Vol%	Lb/Hr	Wt%	Lb/Hr	Wt%	Lb/Hr
GASES:									
Carbon Monoxide	28.01	23.91	744	23.91	520			23.91	82
Hydrogen	2.02	14.58	33	14.58	23			14.58	4
Carbon Dioxide	44.01	5.45	266	5.45	186			5.45	29
Methane	16.04	1.35	24	1.35	17			1.35	3
Nitrogen	28.01	48.70	1,515	48.70	1,060			48.70	167
Argon	39.95	0.56	25	0.56	17			0.56	3
Oxygen	32.00	0.00	0	0.00	0			0.00	0
Ammonia	17.03	0.02	0	0.02	0			0.02	0
Hydrogen Sulfide	34.08	0.00	0	0.00	0			0.00	0
Carbonyl Sulfide	60.08	0.00	0	0.00	0			0.00	0
Sulfur Dioxide	64.06	0.00	0	0.00	0			0.00	0
Water Vapor	18.02	5.43	109	5.43	76			5.43	12
Hydrogen Chloride	36.46	0.00	0	0.00	0			0.00	0
TOTAL GASES		100.00	2,715	100.00	1,900			100.00	300
Gas Flow, Lb Moles/Hr			111.0		77.7				12.3
Molecular Weight, Gases			24.45		24.45				24.45
Gas Volume, ACFM			56.4		33.6				9.0
Gas Volume, SCFM			702		491				78
LIQUIDS:									
Water	18.02					100.00	854		
SOLIDS:									
Carbon	12.01							54.20	125
Hydrogen	1.01							0.33	1
Oxygen	16.00							0.70	2
Nitrogen	14.01							0.41	1
Sulfur	32.06							0.36	1
Chlorides -	35.45							0.00	0
Ash								44.00	102
Moisture	18.02							0.00	0
TOTAL SOLIDS								100.00	231
SORBENT:									
CaO	56.08							74.50	25
CaCO3	100.09							0.00	0
CaS	72.14							12.44	4
CaSO4	136.14							0.00	0
MgO	40.31							3.26	1
MgCO3	84.32							0.00	0
Inerts								9.79	3
TOTAL SORBENT								100.00	34
TOTAL FLOW, Lb/Hr			2,715		1,900		854		565
HEATING VALUE:									
Gas LHV, Btu/SCF			129		129				129
Gaseous Fuel LHV, MMBtu/hr			5.4		3.8				0.6
TEMPERATURE, F			270 △3		350		553		670
PRESSURE, PSIA			257		335		1,075		276

HEAT AND MATERIAL BALANCE

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HEAT AND MATERIAL BALANCE - BASE CASE
UNDRIED SUFCO COAL WITH TRANSPORT DESULFURIZER

IDENTIFICATION	Molecular Weight	37 Filter Solids From Screw Cooler		38 (Rev. 3) Gas From Sulfator Cyclone		39 Flue Gas (Rev. 3) to BH Filter		40 (Note 1) Pressurization Air Vent	
		Wt%	Lb/Hr	Vol%	Lb/Hr	Vol%	Lb/Hr	Vol%	Lb/Hr
GASES:									
Carbon Monoxide	28.01			0.00	0	0.00	0	0.00	0
Hydrogen	2.02			0.00	0	0.00	0	0.00	0
Carbon Dioxide	44.01			15.65	7,484	9.65	18,033	0.00	0
Methane	16.04			0.00	0	0.00	0	0.00	0
Nitrogen	28.01			76.52	23,292	77.23	91,879	78.00	2,970
Argon	39.95			0.88	382	0.89	1,507	0.90	49
Oxygen	32.00			3.67	1,276	10.33	14,044	20.82	906
Ammonia	17.03			0.00	1	0.00	1	0.00	0
Hydrogen Sulfide	34.08			0.00	0	0.00	0	0.00	0
Carbonyl Sulfide	60.08			0.00	0	0.00	0	0.00	0
Sulfur Dioxide	64.06			0.00	2	0.01	37	0.00	0
Water Vapor	18.02			3.28	641	1.88	1,438	0.29	7
Hydrogen Chloride	36.46			0.00	0	0.00	0	0.00	0
TOTAL GASES				100.00	33,078	100.00	126,939	100.00	3,932
Gas Flow, Lb Moles/Hr					1,086.6		4,246.7		136.0
Molecular Weight, Gases					30.44		29.89		28.92
Gas Volume, ACFM					27413.7		45215.0		1084.2
Gas Volume, SCFM					6,870		26,849		860
LIQUIDS:									
Water	18.02								
						Wt%			
SOLIDS:									
Carbon	12.01	54.20	2,656			2.35	53		
Hydrogen	1.01	0.33	16			0.00	0		
Oxygen	16.00	0.70	34			1.52	34		
Nitrogen	14.01	0.41	20			0.88	20		
Sulfur	32.06	0.36	18			0.01	0		
Chlorides -	35.45	0.00	0			0.00	0		
Ash		44.00	2,156			95.24	2,156		
Moisture	18.02	0.00	0			0.00	0		
TOTAL SOLIDS		100.00	4900			100	2,264		
SORBENT:									
CaO	56.08	74.50	539			74.50	539		
CaCO3	100.09	0.00	0			0.00	0		
CaS	72.14	12.44	90			12.44	90		
CaSO4	136.14	0.00	0			0.00	0		
MgO	40.31	3.26	24			3.26	24		
MgCO3	84.32	0.00	0			0.00	0		
Inerts		9.79	71			9.79	71		
TOTAL SORBENT		100	724			100	724		
TOTAL FLOW, Lb/Hr			5,624		33,078		129,926		3,932
HEATING VALUE:									
Gas LHV, Btu/SCF									
Gaseous Fuel LHV, MMBtu/hr									
TEMPERATURE, F		(Rev. 3)	500		1,600		350		120
PRESSURE, PSIA			263		15		14		13

Note 1 : Time averaged flow.

HEAT AND MATERIAL BALANCE - BASE CASE
UNDRIED SUFCO COAL WITH TRANSPORT DESULFURIZER

IDENTIFICATION	Molecular Weight	41 Δ3 Total BFW From Sec. 800		42 Recycle Gas To Gasifier		43 (Note 1) Ash Hopper Δ3 Vent Gas Δ3		44 (Note 1) Fines Hopper Δ3 Vent Gas Δ3	
		Wt%	Lb/Hr	Vol%	Lb/Hr	Vol%	Lb/Hr	Vol%	Lb/Hr
GASES:									
Carbon Monoxide	28.01			23.91	4,231	25.21	50	25.21	127
Hydrogen	2.02			14.58	186	15.37	2	15.37	6
Carbon Dioxide	44.01			5.45	1,516	5.75	18	5.75	45
Methane	16.04			1.35	137	1.42	2	1.42	4
Nitrogen	28.01			48.70	8,618	51.34	102	51.34	259
Argon	39.95			0.56	141	0.59	2	0.59	4
Oxygen	32.00			0.00	0	0.00	0	0.00	0
Ammonia	17.03			0.02	2	0.02	0	0.02	0
Hydrogen Sulfide	34.08			0.00	0	0.00	0	0.00	0
Carbonyl Sulfide	60.08			0.00	0	0.00	0	0.00	0
Sulfur Dioxide	64.06			0.00	0	0.00	0	0.00	0
Water Vapor	18.02			5.43	619	0.30	0	0.30	1
Hydrogen Chloride	36.46			0.00	0	0.00	0	0.00	0
TOTAL GASES				100.00	15,448	100.00	176	100.00	446
Gas Flow, Lb Moles/Hr					631.7		7.1		18.0
Molecular Weight, Gases					24.45		24.80		24.80
Gas Volume, ACFM					273.1		2.8		8.4
Gas Volume, SCFM					3,994		45		114
LIQUIDS:									
Water	18.02	100.00	157,995						
SOLIDS:									
Carbon	12.01								
Hydrogen	1.01								
Oxygen	16.00								
Nitrogen	14.01								
Sulfur	32.06								
Chlorides -	35.45								
Ash									
Moisture	18.02								
TOTAL SOLIDS									
SORBENT:									
CaO	56.08								
CaCO3	100.09								
CaS	72.14								
CaSO4	136.14								
MgO	40.31								
MgCO3	84.32								
Inerts									
TOTAL SORBENT									
TOTAL FLOW, Lb/Hr			157,995		15,448		176		446
HEATING VALUE:									
Gas LHV, Btu/SCF					129		136		136
Gaseous Fuel LHV, MMBtu/hr					30.9		0.4		0.9
TEMPERATURE, F			240	Δ3	350		230		230
PRESSURE, PSIA			1,075		335		310		263

Note: 1. Streams 43 and 44 are time averaged flow rates.

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HEAT AND MATERIAL BALANCE - BASE CASE
UNDRIED SUFCO COAL WITH TRANSPORT DESULFURIZER

IDENTIFICATION	Molecular Weight	45 /3\ BFW to Air Precooler		46 /3\ Ash To Collection Hopper		47 /3\ BFW to Recycle Gas Cooler		48 /3\ Recycle Gas To Filter	
		Wt%	Lb/Hr	Wt%	Lb/Hr	Wt%	Lb/Hr	Vol%	Lb/Hr
GASES:									
Carbon Monoxide	28.01			23.91	438			23.91	438
Hydrogen	2.02			14.58	19			14.58	19
Carbon Dioxide	44.01			5.45	157			5.45	157
Methane	16.04			1.35	14			1.35	14
Nitrogen	28.01			48.70	893			48.70	893
Argon	39.95			0.56	15			0.56	15
Oxygen	32.00			0.00	0			0.00	0
Ammonia	17.03			0.02	0			0.02	0
Hydrogen Sulfide	34.08			0.00	0			0.00	0
Carbonyl Sulfide	60.08			0.00	0			0.00	0
Sulfur Dioxide	64.06			0.00	0			0.00	0
Water Vapor	18.02			5.43	64			5.43	64
Hydrogen Chloride	36.46			0.00	0			0.00	0
TOTAL GASES				100.00	1,600			100.00	1600
Gas Flow, Lb Moles/Hr					65.4				65.4
Molecular Weight, Gases					24.45				24.45
Gas Volume, ACFM					36.2				36.2
Gas Volume, SCFM					414				414
LIQUIDS:									
Water	18.02	100.00	51,550			100.00	62,887		
SOLIDS:									
Carbon	12.01			27.19	1,685				
Hydrogen	1.01			0.07	5				
Oxygen	16.00			0.35	22				
Nitrogen	14.01			0.22	14				
Sulfur	32.06			0.17	10				
Chlorides -	35.45			0.00	0				
Ash				72.00	4,463				
Moisture	18.02			0.00	0				
TOTAL SOLIDS				100.00	6,199				
SORBENT:									
CaO	56.08			74.50	1305.26				
CaCO3	100.09			0.00	0.00				
CaS	72.14			12.44	217.98				
CaSO4	136.14			0.00	0.00				
MgO	40.31			3.26	57.17				
MgCO3	84.32			0.00	0.00				
Inerts				9.79	171.59				
TOTAL SORBENT				100.00	1752.00				
TOTAL FLOW, Lb/Hr			51,550		9,551		62,887		1,600
HEATING VALUE:									
Gas LHV, Btu/SCF									
Gaseous Fuel LHV, MMBtu/hr									
TEMPERATURE, F			240		500		240		500
PRESSURE, PSIA			1,075		310		1,075		310

HEAT AND MATERIAL BALANCE - BASE CASE
UNDRIED SUFCO COAL WITH TRANSPORT DESULFURIZER

IDENTIFICATION	Molecular Weight	49 (3) Air To Sulfator		50 (3) Steam From Product Gas Trim Cooler		51 (3) Net Steam From Sulfator Steam Drum		52 (3) Steam From Product Gas Cooler	
		Vol%	Lb/Hr	Vol%	Lb/Hr	Vol%	Lb/Hr	Vol%	Lb/Hr
GASES:									
Carbon Monoxide	28.01	0.00	0						
Hydrogen	2.02	0.00	0						
Carbon Dioxide	44.01	0.00	0						
Methane	16.04	0.00	0						
Nitrogen	28.01	78.00	20,677						
Argon	39.95	0.90	339						
Oxygen	32.00	20.82	6,305						
Ammonia	17.03	0.00	0						
Hydrogen Sulfide	34.08	0.00	0						
Carbonyl Sulfide	60.08	0.00	0						
Sulfur Dioxide	64.06	0.00	0						
Water Vapor	18.02	0.29	49	100.00	34,182	100.00	42,704	100.00	59,297
Hydrogen Chloride	36.46	0.00	0						
TOTAL GASES		100.00	27,370	100.00	34,182	100.00	42,704	100.00	59,297
Gas Flow, Lb Moles/Hr			946.4		1,897.4		2,370.5		3,291.5
Molecular Weight, Gases			28.92		18.02		18.02		18.02
Gas Volume, ACFM			4486.3		239.8		299.6		416.0
Gas Volume, SCFM			5,983		11,998		14,989		20,813
LIQUIDS:									
Water	18.02								
SOLIDS:									
Carbon	12.01								
Hydrogen	1.01								
Oxygen	16.00								
Nitrogen	14.01								
Sulfur	32.06								
Chlorides -	35.45								
Ash									
Moisture	18.02								
TOTAL SOLIDS									
SORBENT:									
CaO	56.08								
CaCO3	100.09								
CaS	72.14								
CaSO4	136.14								
MgO	40.31								
MgCO3	84.32								
Inerts									
TOTAL SORBENT									
TOTAL FLOW, Lb/Hr			27,370		34,182		42,704		59,297
HEATING VALUE:									
Gas LHV, Btu/SCF									
Gaseous Fuel LHV, MMBtu/hr									
TEMPERATURE, F			150		553		553		553
PRESSURE, PSIA			23		1,075		1,075		1,075

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HEAT AND MATERIAL BALANCE - BASE CASE
UNDRIED SUFCO COAL WITH TRANSPORT DESULFURIZER

IDENTIFICATION	Molecular Weight	53 △3 Total Blowdown to Sec. 800		54 △3 Steam From Gasifier Steam Drum		55 △3 Total Gas Flow To HGF		56 △3 Pri. Solids Cooler Fluidization Air	
		Wt%	Lb/Hr	Vol%	Lb/Hr	Vol%	Lb/Hr	Vol%	Lb/Hr
GASES:									
Carbon Monoxide	28.01					23.89	87,124	0.00	0
Hydrogen	2.02					14.57	3,824	0.00	0
Carbon Dioxide	44.01					5.45	31,209	0.00	0
Methane	16.04					1.35	2,812	0.00	0
Nitrogen	28.01					48.66	177,460	78.00	738
Argon	39.95					0.56	2,897	0.90	12
Oxygen	32.00					0.00	0	20.82	225
Ammonia	17.03					0.02	42	0.00	0
Hydrogen Sulfide	34.08					0.00	9	0.00	0
Carbonyl Sulfide	60.08					0.00	0	0.00	0
Sulfur Dioxide	64.06					0.00	0	0.00	0
Water Vapor	18.02			100.00	112,193	5.51	12,912	0.29	2
Hydrogen Chloride	36.46					0.00	0	0.00	0
TOTAL GASES				100.00	112,193	100.00	318,289		977
Gas Flow, Lb Moles/Hr					6,227.8		13018.7		33.8
Molecular Weight, Gases					18.02		24.45		28.92
Gas Volume, ACFM					787.1		12597.7		
Gas Volume, SCFM					39,380		82,310		
LIQUIDS:									
Water	18.02	100.00	3,098						
SOLIDS:						Wt%			
Carbon	12.01					54.20	2,656		
Hydrogen	1.01					0.33	16		
Oxygen	16.00					0.70	34		
Nitrogen	14.01					0.41	20		
Sulfur	32.06					0.36	18		
Chlorides -	35.45					0.00	0		
Ash						44.00	2,156		
Moisture	18.02					0.00	0		
TOTAL SOLIDS						100.00	4,900		
SORBENT:									
CaO	56.08					74.50	539		
CaCO3	100.09					0.00	0		
CaS	72.14					12.44	90		
CaSO4	136.14					0.00	0		
MgO	40.31					3.26	24		
MgCO3	84.32					0.00	0		
Inerts						9.79	71		
TOTAL SORBENT						100.00	724		
TOTAL FLOW, Lb/Hr			3,098		112,193		323,913		977
HEATING VALUE:									
Gas LHV, Btu/SCF							129		
Gaseous Fuel LHV, MMBtu/hr							637.0		
TEMPERATURE, F			553		553		1,011		110
PRESSURE, PSIA			1,075		1,075		272		155

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HEAT AND MATERIAL BALANCE - BASE CASE
UNDRIED SUFCO COAL WITH TRANSPORT DESULFURIZER

IDENTIFICATION	Molecular Weight	57 Total BFW To Sulfator HRSG		58 Total Steam Export to Sec. 800		59 Air To Fines Combustor		60 Fines Combustor Effluents To HRSG	
		Wt%	Lb/Hr	Vol%	Lb/Hr	Vol%	Lb/Hr	Vol%	Lb/Hr
GASES:									
Carbon Monoxide	28.01					0.00	0	0.00	0
Hydrogen	2.02					0.00	0	0.00	0
Carbon Dioxide	44.01					0.00	0	9.65	18,033
Methane	16.04					0.00	0	0.00	0
Nitrogen	28.01					78.00	67,957	77.23	91,879
Argon	39.95					0.90	1,115	0.89	1,507
Oxygen	32.00					20.82	20,722	10.33	14,044
Ammonia	17.03					0.00	0	0.00	1
Hydrogen Sulfide	34.08					0.00	0	0.00	0
Carbonyl Sulfide	60.08					0.00	0	0.00	0
Sulfur Dioxide	64.06					0.00	0	0.01	37
Water Vapor	18.02			100.00	154,897	0.29	160	1.88	1,438
Hydrogen Chloride	36.46					0.00	0	0.00	0
TOTAL GASES				100.00	154,897	100.00	89,954	100.00	126,939
Gas Flow, Lb Moles/Hr					8,598.2		3,110.3		4,246.7
Molecular Weight, Gases					18.02		28.92		29.89
Gas Volume, ACFM					1,294.2		19268.7		117542.6
Gas Volume, SCFM					54,369		19,665		26,849
LIQUIDS:									
Water	18.02	100.00	43,558						
SOLIDS:								Wt%	
Carbon	12.01							2.35	53
Hydrogen	1.01							0.00	0
Oxygen	16.00							1.52	34
Nitrogen	14.01							0.88	20
Sulfur	32.06							0.01	0
Chlorides -	35.45							0.00	0
Ash								95.24	2,156
Moisture	18.02							0.00	0
TOTAL SOLIDS								100.00	2,264
SORBENT:									
CaO	56.08							74.50	539
CaCO3	100.09							0.00	0
CaS	72.14							12.44	90
CaSO4	136.14							0.00	0
MgO	40.31							3.26	24
MgCO3	84.32							0.00	0
Inerts								9.79	71
TOTAL SORBENT								100.00	724.00
TOTAL FLOW, Lb/Hr			43,558		154,897		89,954		129,926
HEATING VALUE:									
Gas LHV, Btu/SCF									
Gaseous Fuel LHV, MMBtu/hr									
TEMPERATURE, F			240		600		150		1,800
PRESSURE, PSIA			1,075		1,020		18		15

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HEAT AND MATERIAL BALANCE - BASE CASE
UNDRIED SUFCO COAL WITH TRANSPORT DESULFURIZER

IDENTIFICATION	Molecular Weight	61 Cooled Extraction Air To C201		62 BFW/Steam From E607 To SG401		63 Total Desulfurizer Aeration Gas		64 Sulfator Fines From BH Filter	
		Vol%	Lb/Hr	Vol%	Lb/Hr	Vol%	Lb/Hr	Wt%	Lb/Hr
GASES:									
Carbon Monoxide	28.01	0.00	0			23.91	3,600		
Hydrogen	2.02	0.00	0			14.58	158		
Carbon Dioxide	44.01	0.00	0			5.45	1,289		
Methane	16.04	0.00	0			1.35	116		
Nitrogen	28.01	78.00	163,304			48.70	7,332		
Argon	39.95	0.90	2,678			0.56	120		
Oxygen	32.00	20.82	49,797			0.00	0		
Ammonia	17.03	0.00	0			0.02	2		
Hydrogen Sulfide	34.08	0.00	0			0.00	0		
Carbonyl Sulfide	60.08	0.00	0			0.00	0		
Sulfur Dioxide	64.06	0.00	0			0.00	0		
Water Vapor	18.02	0.29	385	100.00	196	5.43	526		
Hydrogen Chloride	36.46	0.00	0			0.00	0		
TOTAL GASES		100.00	216,164	100.00	196	100	13,144		
Gas Flow, Lb Moles/Hr			7,474		11		538		
Molecular Weight, Gases			28.92		18.02		24.45		
Gas Volume, ACFM			4912.8		1.4		232.3		
Gas Volume, SCFM			47,255		69		3,398		
LIQUIDS:									
Water	18.02								
SOLIDS:									
Carbon	12.01							2.35	53
Hydrogen	1.01							0.00	0
Oxygen	16.00							1.52	34
Nitrogen	14.01							0.88	20
Sulfur	32.06							0.01	0
Chlorides -	35.45							0.00	0
Ash								95.24	2,156
Moisture	18.02							0.00	0
TOTAL SOLIDS								100	2,264
SORBENT:									
CaO	56.08							74.50	539
CaCO3	100.09							0.00	0
CaS	72.14							12.44	90
CaSO4	136.14							0.00	0
MgO	40.31							3.26	24
MgCO3	84.32							0.00	0
Inerts								9.79	71
TOTAL SORBENT								100	724
TOTAL FLOW, Lb/Hr			216,164		196		13,144		2,988
HEATING VALUE:									
Gas LHV, Btu/SCF							129		
Gaseous Fuel LHV, MMBtu/hr							26.3		
TEMPERATURE, F			110		553		350		350
PRESSURE, PSIA			155		1,075		335		14

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HEAT AND MATERIAL BALANCE - BASE CASE
UNDRIED SUFCO COAL WITH TRANSPORT DESULFURIZER

IDENTIFICATION	Molecular Weight	65 △3 Cooled Product Gas To Desulfurizer		66 (Note 1) △3 Sorbent Recirculation to Desulfurizer		67 △3 Spent Sorbent To Regenerator		68 △3 Sorbent Regenerant Gas	
		Vol%	Lb/Hr	Wt%	Lb/Hr	Wt%	Lb/Hr	Vol%	Lb/Hr
GASES:									
Carbon Monoxide	28.01	23.89	82,996					0.00	0
Hydrogen	2.02	14.57	3,643					0.00	0
Carbon Dioxide	44.01	5.44	29,708					0.00	0
Methane	16.04	1.35	2,679					0.00	0
Nitrogen	28.01	48.65	169,052					83.81	626
Argon	39.95	0.56	2,760					0.96	10
Oxygen	32.00	0.00	0					0.00	0
Ammonia	17.03	0.02	40					0.00	0
Hydrogen Sulfide	34.08	0.03	127					0.00	0
Carbonyl Sulfide	60.08	0.00	30					0.00	0
Sulfur Dioxide	64.06	0.00	0					14.91	255
Water Vapor	18.02	5.50	12,284					0.31	1
Hydrogen Chloride	36.46	0.00	0					0.00	0
TOTAL GASES		100.00	303,319					99.99	892
Gas Flow, Lb Moles/Hr			12,404						26.65
Molecular Weight, Gases			24						33.47
Gas Volume, ACFM			11989.2						32.1
Gas Volume, SCFM			78,425						168
LIQUIDS:									
Water	18.02								
		Wt%							
SOLIDS:									
Carbon	12.01	54.20	2,531						
Hydrogen	1.01	0.33	15						
Oxygen	16.00	0.70	33						
Nitrogen	14.01	0.41	19						
Sulfur	32.06	0.36	17						
Chlorides -	35.45	0.00	0						
Ash		44.00	2,054						
Moisture	18.02	0.00	0						
TOTAL SOLIDS		100.00	4,669						
SORBENT:									
CaO	56.08	74.50	514						
CaCO3	100.09	0.00	0						
CaS	72.14	12.44	86						
CaSO4	136.14	0.00	0						
MgO	40.31	3.26	23						
MgCO3	84.32	0.00	0						
Inerts		9.79	68						
TOTAL SORBENT		100.00	690		694,000		9,064		
TOTAL FLOW, Lb/Hr			308,678		694,000		9,064		892
HEATING VALUE:									
Gas LHV, Btu/SCF			129						
Gaseous Fuel LHV, MMBtu/hr			607.4						
TEMPERATURE, F			1,032		1,013		1,013		1,368
PRESSURE, PSIA			276		274		278		272

Note 1: Sorbent referred to in streams 66, 67, and 69 is the external desulfurizer sorbent.

HEAT AND MATERIAL BALANCE - BASE CASE
UNDRIED SUFCO COAL WITH TRANSPORT DESULFURIZER

IDENTIFICATION	Molecular Weight	69 △3 Regenerated Sorbent To Desulfurizer		70 △3 Desulf Standpipe Aeration Gas		71 △3 Natural Gas To Fines Combustor		72 △3 Steam From Pri. Solids Cooler	
		Wt%	Lb/Hr	Vol%	Lb/Hr	Vol%	Lb/Hr	Vol%	Lb/Hr
GASES:									
Carbon Monoxide	28.01			23.91	644				
Hydrogen	2.02			14.58	28				
Carbon Dioxide	44.01			5.45	231				
Methane	16.04			1.35	21				
Nitrogen	28.01			48.70	1,312				
Argon	39.95			0.56	21				
Oxygen	32.00			0.00	0				
Ammonia	17.03			0.02	0				
Hydrogen Sulfide	34.08			0.00	0				
Carbonyl Sulfide	60.08			0.00	0				
Sulfur Dioxide	64.06			0.00	0				
Water Vapor	18.02			5.43	94			100.00	18,518
Hydrogen Chloride	36.46			0.00	0				
TOTAL GASES				100.00	2,352		146	100.00	18,518
Gas Flow, Lb Moles/Hr					96		8		1,028
Molecular Weight, Gases					24.45		17.20		18.02
Gas Volume, ACFM					41.6		10.71		129.9
Gas Volume, SCFM					608		54		6,500
LIQUIDS:									
Water	18.02								
SOLIDS:									
Carbon	12.01								
Hydrogen	1.01								
Oxygen	16.00								
Nitrogen	14.01								
Sulfur	32.06								
Chlorides -	35.45								
Ash									
Moisture	18.02								
TOTAL SOLIDS									
SORBENT:									
CaO	56.08								
$CaCO_3$	100.09								
CaS	72.14								
$CaSO_4$	136.14								
MgO	40.31								
$MgCO_3$	84.32								
Inerts									
TOTAL SORBENT			9,000						
TOTAL FLOW, Lb/Hr			9,000		2,352		146		18,518
HEATING VALUE:									
Gas LHV, Btu/SCF					129		936		
Gaseous Fuel LHV, MMBtu/hr					4.7		3.0		
TEMPERATURE, F			1,368		350		52		553
PRESSURE, PSIA			277		335		73		1,075

HEAT AND MATERIAL BALANCE - BASE CASE
UNDRIED SUFCO COAL WITH TRANSPORT DESULFURIZER

IDENTIFICATION	Molecular Weight	73 Aeration Rec. Gas to HGF Bottom Cone		74 Desulfurizer J-leg Aeration Gas	
		Vol%	Lb/Hr	Vol%	Lb/Hr
GASES:					
Carbon Monoxide	28.01	23.91	27	23.91	1,833
Hydrogen	2.02	14.58	1	14.58	80
Carbon Dioxide	44.01	5.45	10	5.45	657
Methane	16.04	1.35	1	1.35	59
Nitrogen	28.01	48.70	56	48.70	3,733
Argon	39.95	0.56	1	0.56	61
Oxygen	32.00	0.00	0	0.00	0
Ammonia	17.03	0.02	0	0.02	1
Hydrogen Sulfide	34.08	0.00	0	0.00	0
Carbonyl Sulfide	60.08	0.00	0	0.00	0
Sulfur Dioxide	64.06	0.00	0	0.00	0
Water Vapor	18.02	5.43	4	5.43	268
Hydrogen Chloride	36.46	0.00	0	0.00	0
TOTAL GASES		100	100	100.00	6,692
Gas Flow, Lb Moles/Hr			4.09		274
Molecular Weight, Gases			24.45		24.45
Gas Volume, ACFM			1.77		118.3
Gas Volume, SCFM			25.85		1,730
LIQUIDS:					
Water	18.02				
SOLIDS:					
Carbon	12.01				
Hydrogen	1.01				
Oxygen	16.00				
Nitrogen	14.01				
Sulfur	32.06				
Chlorides -	35.45				
Ash					
Moisture	18.02				
TOTAL SOLIDS					
SORBENT:					
CaO	56.08				
CaCO3	100.09				
CaS	72.14				
CaSO4	136.14				
MgO	40.31				
MgCO3	84.32				
Inerts					
TOTAL SORBENT					
TOTAL FLOW, Lb/Hr			100		6,692
HEATING VALUE:					
Gas LHV, Btu/SCF			129		129
Gaseous Fuel LHV, MMBtu/hr			0.2		13.4
TEMPERATURE, F			350		350
PRESSURE, PSIA			335		335

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List of Acronyms

Acronym	Meaning
IGCC	Integrated Gasification Combined Cycle
SPPCo	Sierra Pacific Power Company
DOE	Department of Energy
KRW	Kellogg/Rust/Westinghouse
MWK	M. W. Kellogg
Nox	Nitrous Oxides
LASH	Limestones and Ash
KBR	Kellogg, Brown, and Root
GE	General Electric
DCS	Distributed Control System
FW USA	Foster Wheeler USA
FW	Foster Wheeler
CCT	Clean Coal Technology
D&E	Design and Engineering
CM	Construction Manager
STOP	Safety Training Observation Program
SUFCO	Southern Utah Fuel Company
BTU	British Thermal Unit
Sorbent	Sulfur absorbent beads
Syngas	Synthetic gas
HRSG	Heat Recovery Steam Generator
UT	Ultrasound Thickness
X#	X Pounds
I&C	Instrument & Control
PSIG	Pound per Square Inch Gage
Psia	Pounds per Square inch Absolut
PLC	Programmable Logic Computer
OK	Yes
TECO	Tampa Electric Company
O&M	Operations and Maintenance
HTF	Heat Transfer Fluid
Hi-Hi	Vessel is Full
PDT	Pressure Differential Transmitter
°F	Degrees Fahrenheit
DC	Direct Current
V	Volts

EFD	Engineering Flow Diagram
Hi-Vac	Pinon Vacuum Device
HP	High Pressure
LP	Low Presssure
#X	Number of X
Mils	Millionths of an Inch
MarkV	Turbine Control System
Y2K	Year 2000
P&ID	Piping and Instrument Diagram
PFD	Process Flow Diagram
UNIRAM	Unit Reliability and Maintainability
EFOR	Equivalent Forced Outage Rate
EA	Equivalent Availability
R&M	Reliability and Maintainability
MTTR	Mean Time to Repair
HR	Hot Restart
IR	Intermediate Restart
CR	Cold Restart
TPD	Tons Per Day
Mwe	Megawatt
Km	Kilometer
MCE	Maximum Credible Earthquake
EHSS	Environmental, Health, Safety, and Socioeconomic
EIS	Environmental Impact Statement
OSHA	Occupational Safety and Health Organization
DHEW	Department of Health, Education and Welfare
NIOSH	National Institute of Safety and Health
KV	Kilovolt
RPM	Revolutions per Minute
DOT	Department of Transportation
LHV	Lower Heating Value
Pf	Power Factor
@	At
SCF	Standard Cubic Feet
PSV	Pressure Safety Valve
CEM	Continuous Emissions Monitoring
PEL	Permissible Exposure Limit
IDLH	Immediately Dangerous to Life and Health

ERPG	Emergency Response Planning Guideline
CPR	Cardio-Pulmonary Resuscitation

7.0 Project Summary

The Pinon Pine IGCC Project was implemented and constructed to demonstrate new technology. It is the first ever air-blown Gasification Project involving the process proven at the Waltz Mill Project. The Hot Gas Clean Up developed with the support of the Department of Energy is also the first of its kind.

The initial start-up of the combined cycle portion of the unit went well. The ability of the unit to produce power efficiently and reliably on natural gas as fuel has proven out. Only a few problems with the Combustion Turbine and other sections of this portion of the plant have arisen.

The initial start-up of the Gasifier occurred during January, 1998. A multitude of problems and show-stoppers have arisen. The ability of the Gasifier to produce Syngas of design quality has proven out. Getting the waste products and particulates out of the Syngas stream and removing LASH from the bottom of the Gasifier have been the two major causes of the unit from becoming commercially reliable.

Major successes during the reporting period include operation of the Gasifier. We have been able to fire the unit and control it with ease. The ability to get fuel into the vessel has not proven to be much of a problem. Only on a few occasions has trouble arisen with this portion of the system. So, in conclusion to this, it is apparent that the Gasifier, as it is designed, is a viable means of gasifying coal to produce Syngas.

The seventeen (17) Critical Component Failures documented in this report detail the extreme difficulty that starting up the Gasifier and keeping it running for any period of time has been. Each one of these is a show-stopper and we could not progress until we engineered a way through the obstacle. There are still problems out there that remain that we have not been able to address to this point. Running the unit for extended periods is needed to progress into the Hot Gas Clean Up and Sulfator portions of the plant.

As mentioned earlier, the Tracy Clark Station, which includes the Pinon Pine Project, has been purchased by Wisconsin Public Services. It is their intention to continue to attempt to obtain an extended run out of the unit. This is absolutely needed in order to prove whether we can remove LASH from the bottom of the Gasifier or not. The future commercial viability of the Pinon Gasifier relies on this. A decision on whether to continue with the project or abandon it will rest solely on a start-up of the Gasifier planned during the month of February, 2001.

Availability Assessment of the Tracy Power Station - Unit Number 4 Integrated Gasification Combined-Cycle (IGCC) Power Plant

July 1996

under Purchase Order
PP0071-115-00-004145

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EXECUTIVE SUMMARY

Foster Wheeler USA Corporation (FW USA) contracted with ARINC to conduct an availability assessment of the Piñon Pine 106-MWe (gross) capacity integrated gasification combined-cycle (IGCC) power plant. The plant, to be operated by Sierra Pacific Power Company (SPPCo), will be located at the Tracy Station site near Reno, Nevada. The objective of the study was to determine the expected availability of the plant based upon the design as described in the Technical Baseline document, the plant piping and instrument diagrams (P&IDs), and the process flow diagrams (PFDs). Technical assistance was provided by FW USA and the M.W. Kellogg Company (MWK) for the power island and gasification island respectively.

ARINC's Unit Reliability, Availability, and Maintainability (UNIRAM) software was used to model the plant. It considered 35 plant subsystems. The subsystem models included fault trees representing components that could cause the plant to fail or cause a capacity derating. The reliability and maintainability (R&M) expected of these components directly affects the plant equivalent forced (unplanned) outage rate (EFOR) and its equivalent availability (EA). The plant's availability performance is based on the following: frequency of forced outages, expected time to restore failures, plant design and operational concept, and planned (scheduled) outage hours. With the exception of some Piñon Pine design-specific equipment (e.g., coal gasification, hot gas filter, desulfurizer), most equipment represents commercially available, fully matured designs for which generic R&M data is available from a number of industry sources. R&M data for the plant-specific equipment within the gasification island was provided by MWK.

UNIRAM models were developed for the following three modes of operation:

- **Mode 1.** Synthetic gas (syngas) operation - Plant operates only on syngas at a 97.8-MWe capacity and without natural gas backup, except to restart the plant following an unplanned or planned outage.
- **Mode 2.** Natural gas (natgas) operation - Plant operates at a 90.4-MWe capacity only on natural gas in the combined-cycle mode and without fuel transfer capability to syngas.
- **Mode 3.** IGCC operation - Plant operates at a 97.8-MWe capacity on syngas with natgas backup. Should a syngas interruption occur, the plant is transferred to natgas but operates at a 90.4-MWe capacity.

An important consideration in the study was startup delays that occur after a component failure. These delays are due to the affects of gasification island cool-down and the fuel transfer period required to return the plant to synthetic gas (syngas) operation. These delays can be significant (up to 142 hours), and depend on the mean time to repair (MTTR) of the components. Three restart delay cases were considered:

- **Hot Restart (HR)** - Applies to all components with an MTTR < 36 hours, resulting in an 11.5 hour delay at a plant capacity of 75.3-MWe.
- **Intermediate Restart (IR)** - Applies to all components with 36 ≤ MTTR ≤ 68 hours, resulting in a 42 hour delay at a plant capacity of 70.4-MWe.
- **Cold Restart (CR)** - Applies to all components with an MTTR > 68 hours, resulting in a 142 hour delay at a plant capacity of 69-MWe.

The results of the UNIRAM analysis provide plant EA values of 72% in mode 1 and 94% in mode 2, exceeding the Piñon Pine project EA goals of 70% and 85%, respectively. Due to the serial configuration of the gasification island design, there are numerous single-point failures that will result in loss of syngas production and necessitating transfer to natgas. This results in a high frequency of syngas production failures which, when coupled with restart delays, extends the time that the plant must operate on natgas to 119 days per year.

Of the 232 components represented in the plant IGCC model, 47 have MTTRs that exceed 68 hours, requiring a cold restart delay of 142 hours. These cold restart delays account for 34% of the total annual plant equivalent outage hours (1146 hours), compared to 10% of the total hours for the 144 components that are subject to hot restart delays of 11.5 hours. Improvements that reduce the frequency of plant failures and also reduce MTTRs below 68 hours afford the best opportunity for a reduction in the EFOR of the plant. Due to the strong affect of unplanned maintenance downtime on plant EFOR, it is recommended that the Piñion Pine project organization consider the development of a detailed scheduled maintenance plan to implement annual plant turnarounds, and a study to define the requirements for a predictive (condition-based) maintenance program.

ABBREVIATIONS AND ACRONYMS

ABD	Availability Block Diagram
AF	Availability Factor
AH	Available Hours
BFW	Boiler Feedwater (makeup)
BP	Brief Period
BTU	British Thermal Unit
CCA	Component Criticality Analysis
CR	Cold Restart
DOE	Department of Energy
EA	Equivalent Availability
EFOR	Equivalent Forced Outage Rate
EOH	Equivalent Outage Hours
EPRI	Electric Power Research Institute
ESOH	Equivalent Scheduled Outage Hours
EUDH	Equivalent Unplanned Derated Hours
FOH	Forced Outage Hours
FOR	Forced Outage Rate
FR	Failure Rate
FW USA	Foster Wheeler USA
GRI	Gas Research Institute
GT	Gas Turbine
HHV	Higher Heating Value
HR	Hot Restart
HRSG	Heat Recovery Steam Generator
IGCC	Integrated Gasification Combined-Cycle
IR	Intermediate Restart

ABBREVIATIONS AND ACRONYMS (continued)

LASH	Solids that contain calcimined and sulfidized limestone, and ash
LHV	Lower Heating Value
MBTU/h	Millions of BTUs per hour
MDC	Maximum Dependable Capacity
MDT	Mean Downtime
MTBF	Mean Time Between Failure
MWe	Megawatt
MTTR	Mean Time To Repair
MWK	M.W. Kellogg
Natgas	Natural Gas
O&M	Operating and Maintenance
P&IDs	Piping and Instrumentation Diagrams
PFDs	Process Flow Diagrams
PH	Period Hours
RAM	Reliability, Availability, Maintainability
R&D	Research & Development
R&M	Reliability & Maintainability
ROH	Reserved Outage Hours
SH	Service Hours
SOF	Schedule Outage Factor
SOH	Scheduled Outage Hours
SO_2	Sulfur Dioxide
SPPCo	Sierra Pacific Power Company
ST	Steam Turbine
Syngas	Synthetic Gas
TPD	Tons Per Day
UNIRAM	Unit Reliability Availability Maintainability

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SECTION 1

INTRODUCTION

Foster Wheeler USA Corporation (FW USA) contracted ARINC to conduct an availability assessment of the Piñon Pine 106-MWe (gross) capacity integrated gasification combined-cycle (IGCC) power plant. The plant, to be operated by Sierra Pacific Power Company (SPPCo), will be located at the Tracy Station site near Reno, Nevada. The objective of the study was to determine the expected availability of the plant based upon the design as described in the Technical Baseline document, the plant piping and instrument diagrams (P&IDs), and the process flow diagrams (PFDs). Technical assistance was provided by FW USA and the M.W. Kellogg Company (MWK) for the power island and gasification island respectively.

ARINC's Unit Reliability, Availability, and Maintainability (UNIRAM) software was used to model the plant. The UNIRAM model considered 35 plant subsystems. These subsystems included fault trees representing potential component failures. The reliability and maintainability (R&M) values expected from these components directly affect plant equivalent forced (unplanned) outage rate. The plant's availability performance is based on the following: frequency of forced outages, expected time to restore failures, plant design and operational concept, and planned (scheduled) outage hours. With the exception of some Piñon Pine design-specific equipment (e.g., coal gasification, hot gas filter, desulfurizer), most equipment represents commercially available, fully matured designs for which generic R&M data is available from a number of industry sources (see Appendix A). Commercial off-the-shelf equipment is used extensively throughout the gasification and power islands, materials handling systems, electrical systems, process controls, and balance of plant systems (e.g., water treatment). R&M data for the plant-specific equipment within the gasification island was provided by MWK with consideration of the expected plant operating and maintenance (O&M) policies.

The output of the UNIRAM model is the expected time (hours per year) the plant will be operating at 100% (full capacity state), the zero capacity state, and its various derated capacity states (0% < derating < 100%). The analysis also provides a prediction of the hours per year the plant is expected to be operated on synthetic gas (syngas) and backup natural gas (natgas). UNIRAM also identifies the "critical" components that cause major losses in plant availability.

This characteristic of the UNIRAM model enables design engineers to evaluate cost beneficial improvements to the plant.

This report is divided into six sections. Section 1 is an overall introduction to the report, including a plant description, background information about reliability issues, and definitions. Section 2 presents the technical approach to the analysis, and a brief description of the UNIRAM model and study assumptions. Section 3 presents the results of the availability analysis, criticality analysis and sensitivity analysis. A discussion and analysis of improvements is presented in Section 4. Conclusions and recommendations are summarized in Section 5. References are listed in Section 6. Appendix A provides the descriptions, fault trees, and R&M database for each of the 35 subsystems. Appendix B contains supporting calculations for the model. Appendixes C and D include the UNIRAM data input file and the Technical Baseline document, respectively.

1.1 PLANT DESCRIPTION AND OPERATIONS

The Piñon Pine IGCC power plant is described in the Technical Baseline report (Appendix D) and includes the following areas and functions:

Area 100 - Solids Receiving and Grinding
- Coal receiving, storage, conveying, and preparation
- Coke and limestone receiving and feeding.

Area 200 - Oxidant Compression and Supply
- Air extraction from the gas turbine's compressor, cooling, and compression systems

Area 300 - Coal Gasification
- Coal, coke, and limestone feed
- Gasification process for syngas production
- Solids removal from the gasifier

Area 400 - Gas Stream Heat Recovery
- Cooling of recycle gas, syngas, and steam production from the gasifier Heat Recovery Steam Generator (HRSG)
- Particulate removal and gas transport to the desulfurizer

Area 500 - Gas Stream Particulate Removal
- Final particulate (fines) removal by a hot gas filter and transport to the gas turbine (GT)
- Fines and ash cooling and disposal

Area 600 - Desulfurization

- Syngas desulfurization (sorbant process) and transport to the hot gas filter
- Sorbant regeneration and feed
- Sulfur dioxide (SO_2) removal by a sulfator (atmosphere bubbling-bed, reactor)
- Fines removal, cooling combustion, and disposal

Area 700 - Gas Turbine Generator
- Gas turbine power generation
- Bleed air for gasifier oxidant

Area 800 - Heat Recovery Steam Generator (HRSG)
- Production of superheated steam
- Power generation
- Boiler feedwater makeup, deaeration, and treatment
- Condensate pumping and condenser venting

Area 900 - Recycle Gas Compression
- Recycle gas transport and compression for gasifier fluffing; sulfator transport gas and ash transport from the gasifier to the sulfator
- Recycle gas cooling

Area 1000 - Waste Water Treatment
- Treatment of HRSG blowdown water, sludge from the clarifier, waste from the demineralizer, and sidestream water from the cooling tower

Area 1100 - Solid Waste Handling
- Ash, fines, sulfated limestone and ash (LASH) transport, storage and disposal

Area 1200 - Balance of Plant
- Raw water supply for boiler feedwater (BFW) makeup
- BFW demineralization and treatment cooling tower
- Compressed air and drying for process and instrument control
- Emergency syngas flaring
- Nitrogen generation for system purging
- Electrical services and distribution

The gasification island (Areas 200 - 600, 900) is designed to process 880 tons per day (TPD) of bituminous coal and generate desulfurized syngas free of particulates to the power island (Areas 700 and 800). A KRW air-blown, fluidized-bed coal gasifier produces 285,000 pounds per hour (lb/h) of low-Btu syngas. Approximately 156,000 lb/h of steam is generated within the gasification island HRSGs for transport to the Area 800 HRSG.

A General Electric Model MS6001FA gas turbine generator (61-MWe with syngas) operates on either syngas (primary) or natgas (backup) should syngas be unavailable. While in natgas mode, the gas turbine generator produces 67-MWe). During primary operation (utilizing syngas), gas turbine exhaust passes through the Area 800 HRSG, producing superheated steam (950 psia at 950°F), which is expanded in a condensing-type steam turbine. Steam produced in the area 800 HRSG is mixed with steam from the gasification island to produce 46-MWe from the steam turbine/generator. The total gross power from the gas turbine and steam turbine generators is 106-MWe in the IGCC mode.

During backup operation (utilizing natgas), gas turbine exhaust also passes through the area 800 HRSG producing superheated steam (950 psia at 950°F), which is expanded in a condensing-type steam turbine. However, the steam produced in the area 800 HRSG is not mixed with the steam from the gasification island, and thus only produces 25-MWe from the steam turbine generator. The total gross power from the gas turbine and steam turbine generator (utilizing natgas) is 92-MWe (see Table 1-1).

The plant can operate continuously in either the syngas or combined-cycle mode (natgas). Should the gasification island fail, the plant can execute a rapid transfer to natgas. This crossover results in a reduction in net power from 97.8-MWe to 90.4-Mwe (92.5% of full capacity). This 7.5% derating is due to total loss of the gasification island's steam supply to the steam turbine.

Returning the plant to syngas operation following a plant outage involves one of three restart cases, depending on the mean-time-to-repair (MTTR) required to restore gasification island operations. Due to the effects of gasification process cooling, a restart can require between 11.5 and 142 hours. Restart requires that the plant's capacity be ramped back to 97.8-MW over a prescribed period of time. This restart time period plus the MTTR is called the mean downtime (MDT). The three start-up cases are as follows:

- **Hot Restart (HR)** - For MTTRs < 36 hours, the restart time is 5.5 average "brief period (BP)" hours at 70% of plant maximum dependable capacity (MDC) plus a 6 hour ramping period (RP) at 83% of MDC. The derating for each HR is the weighted average of both the BP and RP hours, which is equal to 77% of MDC.
- **Intermediate Restart (IR)** - For 36 ≤ MTTR ≤ 68 hours, the restart time is 36 BP hours at 70% of MDC, plus 6 RP hours at 83% of MDC. The derating for each IR is the weighted average of both the BP and RP hours, which is equal to 72% of MDC.
- **Cold Restart (CR)** - For MTTR > 68 hours, the restart time is 132 BP hours at 70.0% of MDC, plus 10 RP hours at 83% of MDC. The derating for each CR is the weighted average of both the BP and RP hours, which is equal to 71% of MDC.

A detailed explanation of the startup cases is found in Sections B-1 through B-3 of Appendix B.

The 6 hour (HR and IR cases) and 10 (CR case) RP hours at 83% of MDC represent the natgas to syngas crossover period. A CR represents the time required to start the plant, considering that the gasification island is in a "cold" state. These startup periods, when added to the MTTRs, can result in high plant downtime for some component failures. The quantification of lost availability due to these downtimes is determined using the UNIRAM model. UNIRAM considers the frequency of unplanned outages and deratings that occur within both the power and gasification islands and the corresponding plant downtimes and deratings. Minimizing the frequency of unplanned outages and reducing MDT is important to achieve high availability for the plant.

Table 1-1. Piñon Pine Plant Performance

Performance Metric†	Note	IGCC Mode	IGCC Mode (Humidified)	Natgas Mode
Coal Feed (TPD)	(1)	877.5	879.8	0
Gas Turbine Power (MWe)	(2)	60.75	62.18	66.94
Steam Turbine Power (MWe)	(3)	45.53	43.34	25.00
Gross Power (MWe)	(4)	106.28	105.52	91.94
Auxiliary Power (MWe)	(5)	8.53	8,53	1.50
Net Power (MWe)		97.75	96.99	90.44
Net Heat Rate (Btu (LHV)/kWh)		8,229	8,315	7,149
Net Heat Rate (Btu (HHV)/kWh)		8,528	8,617	7,863
Thermal Efficiency (LHV) %		41.4	41.0	47.7
Thermal Efficiency (HHV) %		40.0	39.6	43.3

† Based on an average ambient condition of 50°F, 20% relative humidity.
(1) Based on 569.4 MBTU/hr of syngas @ 882.6 tons per day (TPD) coal input.
(2) Based on a GE performance run dated 6/10/94, (baseload service at 567.4 MTBU/hr syngas consumption).
(3) Based on a GE steam turbine data.
(4) Based on FW USA ELCO.
(5) Does not include transformer or feeder losses to SPPCo connection.

1.2 AVAILABILITY ISSUES AND DEFINITIONS

The profitability of any power plant is heavily dependent on the cost of fuel, the plant's heat rate, and its availability. Many factors affect plant availability, such as design, operation (e.g., cycled, baseloaded), maintenance policy (e.g., vendor, plant staff, spare parts availability, number of maintenance shifts per day), and design maturity or age. Today's second generation commercial-scale IGCC plants benefit from two decades of research and development (R&D) from the Electric Power Research Institute (EPRI), Department of Energy (DOE), and various pilot-scale projects (e.g., Coolwater).

Modern combined-cycle, natural gas fueled plants are demonstrating excellent availability performance within the electric power industry, cogeneration industry and the independent power producers. The power island uses most recent "F" model gas turbine technology and heat rate improvements afforded by high firing temperatures. A report[1] prepared by ARINC for the Gas Research Institute (GRI), evaluated the availability of 21 modern gas

[1] Reliability of Natural Gas Cogeneration Systems, GRI93/0020, 1992.

turbines (>25-MW) in baseload cogeneration service and operating for 36 unit years. The majority of the gas turbines were in single-unit combined-cycle service and demonstrated an average availability factor of 93.3% and a forced outage rate of 2.1%. These terms and definitions are presented in Tables 1-2 and 1-3 and are consistent with ANSI/IEEE Standard 762.[2] The definitions assume the plant has no reserve shutdown outage hours.

Operational experience for syngas production systems is limited mainly to pilot and demonstration test units. However, with the exception of the KRW gasifier, desulfurizer (MWK transport-type unit) and the hot gas filter (ceramic candle element-type unit), most other components are common to the electric power and petro-chemical industries. Generic reliability data for these industries' equipment (e.g., pumps, conveyors, bins) are available from a number of industry sources (see Section 6, references 1-12). Reliability data for the nongeneric equipment in this study were provided by MWK, and in some cases were based on best engineering judgment (when operational data was unavailable) or from data supplied by the equipment vendors.

The gasification and power islands are single-train continuous flow systems having redundancy only as noted in the following areas:

- Area 100 - Raw coal bins and feeders.
- Area 300 - Extraction steam to the gasifier.
- Area 400 - Phosphate pumps for the HRSG water treatment.
- Area 500 - Fines heat transfer fluid (HTF) pumps.
- Area 800 - High-pressure phosphate pumps, low and high pressure BFW pumps, condenser vacuum and hotwell pumps.
- Area 1200 - Raw water supply and makeup pumps, demineralization, regeneration, and acid pumps, cooling tower pumps, instrument air compressors and dryers, 4.16/0.48 kV transformers, and 13.2-kV service entrance feeders.

Some long-leadtime spares are planned to be available such as rotors for non-redundant compressors (e.g., recycle gas compressor), gas turbine combustors, and fuel nozzles.

Failure of a major component within power island areas 700, 800 or 1200 (e.g., gas turbine, HRSG, plant controls) will result in 100% loss of plant power. Should the steam turbine generator fail, the plant is designed for continuous operation on natgas, with the steam turbine bypassed. However, during non-peak load periods, the steam turbine bypass operation will be limited to 24 hours. Should a failure occur to syngas production (areas 200 - 600 and 900), then the plant shifts to the natgas mode, but at a 7.5% derating to the plant MDC.

[2] IEEE Standard Definitions for Use in Reporting Electric Generating Unit Reliability, Availability, and Productivity.

In order to accurately assess the availability of the plant, a reliability, availability and maintainability (RAM) analysis must consider the following:

- Reduced capacity operation (i.e., derated operation) that occurs for various component failures and startup cases.
- Dependency between plant operating modes (i.e., syngas mode with natgas backup)
- Availability goals and the expected hours of operation in the syngas and natgas modes. This is important since premiums must be paid for "excessive" use of natural gas under some fuel purchase agreements.
- Ability of the plant to operate for a limited period of time should a section of the syngas process be interrupted. This condition, referred to as "surge" capacity, is evident in the materials handling area.
- Scheduled maintenance requirements for the gasification and power islands.
- Extensions to equipment time-to-repair due to administrative delays (i.e., spares unavailability), or time to cool or purge components of combustible gas prior to their repair.
- Restart delays considering the three cases: HR, IR, and CR.

Table 1-2. Availability Definitions

Availability Measure	Symbol	Definition	Equation
Availability Factor	AF	The fraction of the period hours (PH) the plant is capable of producing any power production.	$\frac{PH-FOH-SOH}{PH}$
Equivalent Availability	EA	The fraction of the period hours (PH) the plant is capable of full energy production if limited by only full forced or scheduled outages and deratings.	PH-EFOF-FOH-SOH-ESOH
Forced Outage Rate	FOR	The fraction of the demand period the plant is incapable of any power production due to full forced outages.	$\frac{FOH}{PH-SOH}$
Equivalent Forced Outage Rate	EFOR	The fraction of the demand period the plant is incapable of any energy production due to full forced outages and deratings	$\frac{FOH+EFOH}{PH-SOH}$

Plant economics require that the plant be capable of demonstrating a specific level of availability in the syngas and natgas modes of operation. Because the plant can operate at reduced capacities (deratings), equivalent availability (EA), as defined in Table 1-2, is calculated by UNIRAM to evaluate availability performance. Availability terms are described in Table 1-3. EA accounts for full forced and scheduled outage hours lost at 100% plant capacity in addition to outage hours lost at derated capacity. In other words, an hour lost at 100% capacity is equivalent to 2 hours lost at 50% capacity. Therefore, introducing capacity sharing or derated state operation into a design (e.g., two 50% gasification trains) improves EA but increases capital cost of the plant. The worth of added availability must be evaluated in economic terms and ultimately on the cost of electricity.

The target plant EA goals for the syngas and natgas modes, as defined in the FW USA purchase requisition document 4246-9143-A are 70% and 85% respectively. This translates to 0.70 × 8,760 hours per year or 6,132 hours at a baseload power of 97.8-MW_e (net).
For the remaining time of the year (8,760 - 6,132), the plant is required to be 85% available on natural gas. This translates to 2,234 hours on natural gas or 93 days. Therefore, the combined EA (project definition) assuming that there is no 10% derating when operating on natural gas is calculated as follows:

$$EA = \frac{(8{,}760)0.70 + [8{,}760 - (.70 \times 8{,}760)]0.85}{8.760} \times 100 = 95.5\%$$

This definition is different than EA defined in Table 1-2 which is used by UNIRAM for calculating EA for Mode 3 (IGCC) operations. The Piñion Pine project definition considers that there is no interdependency between the natgas and syngas modes (e.g., restart delays, 10% bypass derating) which of course there is.

Table 1-3. Availability Terms

Term	Symbol	Definition
Period Hours	PH	Hours per year (8,760 h/y).
Scheduled Outage Hours	SOH	The period hours when the plant is planned to be removed from service for planned outages such as overhauls or inspections.
Available Hours	AH	The period hours when the plant is capable of any power generation.
Service Hours	SH	Hours the plant operates at any capacity.
Reserved Outage Hours	ROH	The period hours that the plant is available for generation but not required to operate.
Forced Outage Hours	FOH	The number of hours within the demand period that the plant has lost full capacity due to an unplanned outage.
Equivalent Forced Derated Hours	EFDH	The equivalent number of hours within the demand period that the plant was unavailable at full capacity due to failures that caused plant deratings.
Maximum Dependable Capacity	MDC	The dependable unit capacity in megawatts during winter or summer, whichever is smaller.
Demand Period	--	Period hours that power is planned to be available (PH-SOH).
Equivalent Scheduled Outage Hours	ESOH	The equivalent number of hours within the period hours that the plant has lost full capacity due to scheduled outages.
Equivalent Outage Hours	EOH	The equivalent number of hours within the period hours that the plant has lost full capacity due to planned and unplanned outages.

SECTION 2

UNIRAM MODELING AND ASSUMPTIONS

This section presents an overview of the availability assessment approach, study assumptions, and the Piñon Pine plant UNIRAM model.

2.1 AVAILABILITY MODEL DEVELOPMENT

Development of a UNIRAM model requires an understanding of the plant design and process functionality as defined by the P&IDs and PFDs. Using this information, an availability block diagram (ABD) is prepared. The ABD is a pictorial representation of the "flow" of availability. The ABD includes all subsystems that can affect plant availability.

As shown in Figure 2-1, the ABD includes the various plant areas described in Section 1.1 (called subsystems). The plant capacity contribution, as noted by the percentage values above each box, represents the capacity contribution of each subsystem relative to the maximum plant output. The plant design has numerous 100% subsystems, whose failures can lead to loss of total plant capacity. Each component represented in a 100% subsystem will cause a 100% loss of plant capacity should it fail, unless it is bypassed or otherwise derated as shown in the ABD. Similarly, all components represented within a derated subsystem must cause the derating value indicated. The various derating values for each subsystem are summarized in Section 2.2. A mix of 100% and derated capacity components cannot be represented within a single subsystem. The 92.5% derating bypass, shown around the gasification island subsystems, represents the natural gas/ combined cycle (NATGAS/CC) mode of operation, should any gasification island subsystem fail.

Below certain boxes are noted surge time (ST) values. These numbers represent a period of time during which a subsystem can operate, either at partial or full capacity, without causing a plant shutdown. For instance, for the Coal Handling & Receiving subsystem, the ST value of 480 hours represents a 20-day coal supply for the coal storage dome, and this value is applied to all components within this subsystem. For the Coal Crushing & Transport subsystems (parallel subsystems 2 and 3), failure of subsystem 2 causes a bypass of the "flow" of availability to subsystem 3. Subsystem 2's failure derates the plant to 97% capacity for a period of 24 hours. This ST value is applied to all the components within subsystem 2. This derating is the result of

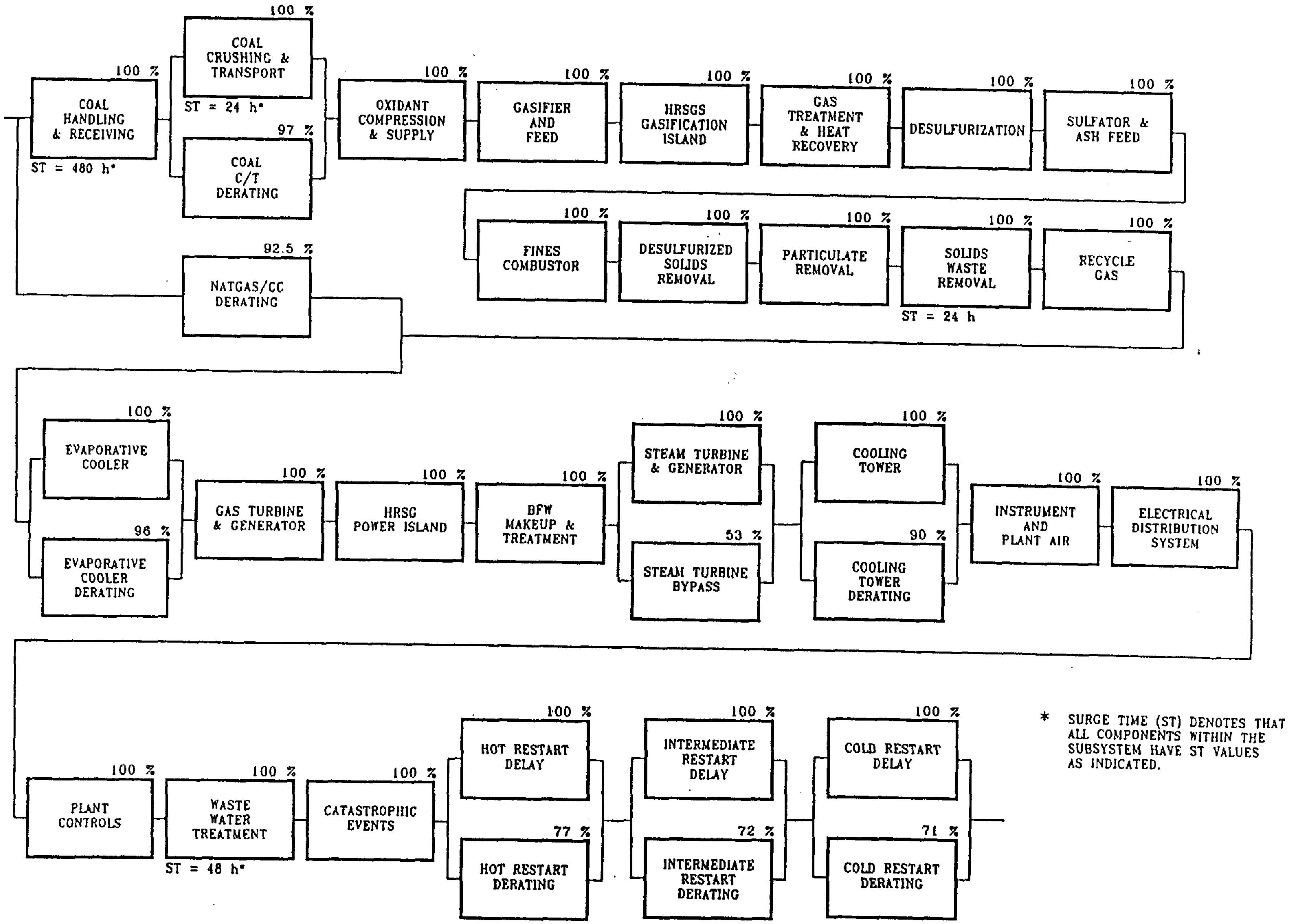


Figure 2-1. Piñon Pine Availability Block Diagram

slowing the coal feedrate and spiking the gasifier with natural gas (natgas). STs are also provided for appropriate components within plant subsystems and are noted in the various subsystem fault trees located in Appendix A.

The three subsystems denoted as restart cases (hot restart-HR, intermediate restart-IR, and cold restart-CR) represent the plant restart deratings as described in Section 1.1. The calculations for the three deratings are located in Appendix B. As discussed in Section 1.1, it is likely that a component failure could lead to 100% loss of plant capacity for a period equal to its mean time to repair (MTTR), and in addition cause a derating to the plant during the plant restart period (i.e., HR, IR, CR). For example, the gas turbine could experience a major failure which would shut down the plant for a period of 100 hours. After the failure has been corrected, the plant would require a cold restart, an additional 142 hours over which time the plant is derated to 71% of its full capacity.

As a second example, the fines combustor could fail, thus causing the plant to switch to natgas. This mode of operation derates the plant to 92.5% of its full capacity over a period of 50 hours. After the failure has been corrected, the plant would require an intermediate restart of 42 hours over which time the plant is derated to 72% of its full capacity.

To properly model these scenarios, HR, IR, and CR delay subsystems were added to the ABD. All 232 components in the plant model are represented in these restart subsystems based upon their MTTR values:

- **HR** - For MTTR < 36 hours.
- **IR** - For 36 ≤ MTTR ≤ 68 hours.
- **CR** - For MTTR > 68 hours.

However, only the restart delay portion of the component mean down time (MDT) is represented in these subsystems to avoid any possibility of double counting the component's downtime contribution to the plant's equivalent forced outage rate (EFOR).

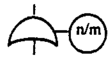
The total plant EFOR calculated by UNIRAM accounts for downtime caused by the component mean time between failure (MTBF), MTTR, and the associated restart delay period. The restart delay fault trees are shown in Appendix A. The following are the restart times for each component within the three restart cases:

- **HR** - Total restart time for a component subject to an HR is 11.5 hours
- **IR** - Total restart time for a component subject to an IR is 42 hours.
- **CR** - Total restart time for a component subject to a CR is 142 hours

Components with failure rates equal to or greater than 10^{-4} have the greatest affect on plant EFOR. Therefore, due to limiting parameters regarding the number of components that can be represented in a subsystem, only those components having failure rates of 10^{-4} failure per year or greater were discretely modeled. The remaining components, those with failure rates less than 10^{-4}, were also accounted for, but were represented by the sum of their failure rates. These components are listed as "Balance of HR Components", "Balance of IR Components", and "Balance of CR Components". Appendix B lists each component represented in the three restart delay subsystems.

The fault trees shown in Appendix A, are represented by three elements: events, gates, and components. The top level event is the subsystem, which can fail. Various "gate" symbols define the logical fault path of the components that lead to a subsystem failure. The following types of gates are used in the UNIRAM model:


OR Gate - The unavailability of one or more of the elements below the gate results in the unavailability of the event above the gate.



Modified OR Gate - The unavailability of "n" or more of the "m" elements below the gate results in the unavailability of the event above the gate.


Exclusive OR Gate - No concurrent failures of the items immediately below this gate are possible


AND Gate - The unavailability of all of the elements below the gate results in the unavailability of the event above the gate (active redundancy).


Multiple AND Gate - The component immediately below this gate is actively redundant with m-copies of itself - all must fail for the gate to fail.

The components under each gate are the third element of the fault tree. Each component represented in the UNIRAM model has an MTBF and an MTTR. These values have unit measures of hours. These fault trees and component R&M data are coded into a UNIRAM input file (see Appendix C).

UNIRAM has a number of analysis options (see Table 2-1) that are fully automated and provide results in tabular and graphical format. The analysis issues discussed in Section 1.2 were addressed by modeling the following operational scenarios:

- **Mode 1.** Synthetic gas (syngas) operation - Plant operates only on syngas at a 97.8-MWe rated capacity and without natural gas backup, except to restart the plant following an unplanned or planned outage.
- **Mode 2.** Natural gas (natgas) operation - Plant operates at a 90.4-MWe rated capacity only on natural gas in the combined-cycle mode and without fuel transfer capability to syngas.
- **Mode 3.** Integrated gasification combined cycle (IGCC) operation - Plant operates at a 97.8-MWe rated capacity on syngas with natgas backup. Should a syngas interruption occur, the plant is transferred to natgas but operates at a 90.4-MWe rated capacity.

Table 2-1. UNIRAM Execution Options

Execution Option	Code	Summary of Results
Baseline	BL	RAM measures for unit and subsystems.
Baseline Run with Load Curve	BC Baseload Only	Percentage of time demand could be met or exceeded; expected annual number of makeup megawatt-hours required.
Component Data Change	CD	Baseline results as altered by changes to selected component MTBF, MDT, surge-time, and delay-time values.
Component Ranking	CR	Rank ordering of components according to unit sensitivity or criticality.
Component Min/Max	MM Baseload Only	Baseline results after changing all component MTBFs and MDTs to their maximum and minimum values (uses ± 3 σ from mean for max and min values when normal distribution parameters are used).
Component Redundancy	RE Baseload Only	Baseline results as altered by addition of an identical component in parallel with existing component.
Rolling Maintenance	RM Baseload Only	Baseline results reflecting effects of various maintenance strategies (or scheduled partial outages) of selected subsystems.
Subsystem Sensitivity	SS	Unit EFOR variation as availability of each subsystem varies (0.80-1.00).
Statistical Uncertainty Analysis	ST Baseload Only	Sample means and 90 percent confidence levels of unit-level RAM measures.
Time-Variant Availability	TA Baseload Only	Unit effectiveness (1-EFOR) as a function of time - includes repair.
Time-Variant Reliability	TR Baseload Only	Unit effectiveness (1-EFOR) as a function of time - no repairs.
Unit Data Change	UD	Baseline results altered by changes to unit RSH, SOH, or period hours.
Weibull	WB Baseload Only	Unit RAM long-term performance using component time-dependent failure rates defined by the Weibull distribution.

2.2 GENERAL ANALYSIS ASSUMPTIONS

The UNIRAM study reflects a level of RAM performance expected of mature plant operations and maintenance: startup and design-related problems are corrected, equipment failures occur randomly with time (i.e., constant failure rates), and sufficient spares are on-site to replace or refurbish failed equipment. Major spares needed for a gas turbine (GT) overhaul are assumed to be purchased on a just-in-time fashion, based on monitoring of the equipment's condition.

The following long lead-time spares are assumed to be on hand at all times to address unscheduled maintenance needs:

- Rotating elements for nonredundant process compressors
- GT fuel nozzle tips and combustion liners (unique to the Piñon Pine IGCC Plant)
- Hot gas filter candles
- Rotating equipment bearings and seals

- Breaker blocks for the crusher
- General instrumentation items, control boards, gaskets, valve repair kits and other related items

The following twenty-four (24) assumptions were made concerning the various aspects of plant performance:

1. Power deratings are based on an average daily temperature of 50°F for 365 days per year.
2. The plant is baseloaded 365 days per year.
3. There are no reserve shutdown periods.
4. Power variations due to ambient air temperature changes are not modeled.
5. The plant design includes strategies to help sustain capacity at temperatures other than 50 °F (i.e. syngas spiking and evaporative cooling).
6. The plant is shutdown (i.e., syngas production) should an outage occur to the power island. Flaring syngas while the power island is shutdown is not considered in the analysis.
7. The plant can operate continuously with the steam turbine bypassed at a 52.2-MWe plant capacity in the syngas mode and a 65.4-MWe plant capacity in the combined-cycle mode.
8. The plant will operate in the natgas or in the combined-cycle mode only in the event of a syngas process failure or immediately following a plant scheduled maintenance or power island failure.
9. A sufficient supply of natural gas is always available to startup the GT 50 so that the plant can be returned to syngas following an outage.
10. The coal receiving and handling subsystem has a 480 hour surge time due to the coal storage dome (X-100).
11. A coal handling system failure, downstream of the storage dome, will require a reduction in feed rate, natural gas spiking, and a reduced plant capacity of 95.0- MWe (3% derating).
12. Power losses due to GT compressor fouling, and long-term wear and tear (i.e. non-recoverable degradation), are not modeled since the frequency of occurrence is not random.
13. The impact of GT steam injection in the syngas mode of operation is not included, since its optimal degree of use has yet to be determined. Its use is accounted for in the combined-cycle mode.
14. The evaporative cooler assists the GT during the summer months by cooling the inlet air to the compressor. Failure of the evaporative cooler results in an annual-average derating of 4%.
15. Syngas process repairs with a MTTR greater than 68 hours will require that the gasification island be depressurized, purged, and shutdown (i.e. cold restart). The plant will immediately be transferred to natural gas when a failure of this type first occurs in order to avoid engendering a complete-plant trip.

16. Syngas process repairs with a MTTR greater than or equal to 36 hours, but less than or equal to 68 hours, will allow gasifier heat conservation (i.e. intermediate restart). The plant will immediately be transferred to natural gas when a failure of this type first occurs in order to avoid engendering a complete-plant trip.

17. Syngas process repairs with a MTTR less than 36 hours will allow a quick return back to syngas (i.e. hot restart). The plant will immediately be transferred to natural gas when a failure of this type first occurs in order to avoid engendering a complete-plant trip.
18. The short transfer time to natural gas and the unreliability of the fuel transfer controllers is assumed to have a negligible effect on plant availability.
19. The cooling tower operates at full capacity only during the summer months. The annual average derating for cooling tower failures is 10%.
20. No plant derating or outage failures are applied to the plant due to lack of disposal truck availability in the solids waste removal and handling area.
21. Failures in the wastewater evaporation system are considered to have very little effect on plant availability, since flow can be directed to a 6-acre evaporation pond if this system is out of service.
22. The adverse affects of cyclic operation on power island component reliability due to syngas interruptions are not modeled.
23. The dust collection system is considered as having a negligible effect on plant availability.
24. All maintenance will be performed using two 12-hour shifts per day and will be vendor assisted.

2.3 SCHEDULED MAINTENANCE PLAN AND ASSUMPTIONS

Scheduled maintenance is the intentional removal of equipment from an available status for inspecting, cleaning, or refurbishing according to a predetermined time schedule. The schedule for performing this maintenance may be based on run-time or service hours, calendar hours, or other factors such as number of starts or operating cycles. The maintenance duration depends on the equipment design, tasks to be performed and many other factors such as number of maintenance shifts per day, labor availability, unforeseen problems, and logistics delays (e.g., spare parts availability).

A scheduled maintenance plan consisting of tasks, schedules, and durations was not available to support the analysis. In its absence, a plan was developed which assumes that the gasification island maintenance is performed concurrently with gas turbine (GT) scheduled maintenance where possible, in order to minimize plant downtime. Scheduled maintenance is assumed to be performed on a six-year repeating cycle as shown in Table 2-2. This maintenance plan reflects current industry practices for General Electric "E" and "F" model GTs (ref.11). Supporting calculations are shown in Section B.4 of Appendix B. The annual ESOH of 207 hours represents a 2.4 percentage point loss of equivalent availability.

Table 2-2. Piñon Pine Scheduled Maintenance Plan†

Year	Task	Duration (Hours)	Extensions (Hours)	SOH (1)	EOH_1 (2)	EOH_2 (3)	ESOH (4)	Annual SOH (5)
1,2,4&5	GT Combustion Inspection	48	8	62	4.4	41.3	107.7	71.8
3	GT Hot Gas-Path Inspection	158	24	198	0	41.3	239.3	39.9
6	GT/Generator Major Overhaul	456	24	528	0	41.3	569.3	94.9
6	ST/Generator Major Overhaul	*	*	*	*	*	*	-
							Total	207 h

† For related information and calculations see Appendix B, Section B-4

* Performed concurrently with the GT overhaul.

(1) Scheduled Outage Hours (SOH): These are the hours needed to perform the indicated inspection, which assumes two 12-hour shifts per day, unlimited labor and spares. Hours indicate 100% loss of plant capacity (97.8-MWe) for the scheduled duration, plus extensions, plus a 10% contingency. During the 62-hours allowed for the combustion inspection, the gasification island will be in the cooldown mode.

(2) Equivalent Outage Hours (EOH_1): This outage is due to gasification island maintenance overlapping the time required for the indicated inspection.

(3) Equivalent Outage Hours (EOH_2): This outage is due to cold restart delay time after the inspection has been completed

(4) Equivalent Scheduled Outage Hours (ESOH): These outage hours indicate 100% loss of plant capacity for the equivalent hours associated with each inspection.

(5) Annual Equivalent Scheduled Outage Hours (ESOH): These outage hours indicate 100% loss of plant capacity for the equivalent hours associated with each inspection if averaged over a six-year cycle.

2.4 RELIABILITY DATABASE

The fault trees shown in Appendix A include over 200 components whose failures lead to a plant forced outage. Recognizing that the majority of these components are used throughout the electric power industry in operating service similar to Piñon Pine, a number of industry data sources were used to develop an R&M database for these industry generic components (see Appendix A and Section 6, References 1-12). These generic components are located throughout the plant subsystems described in the ABD with the exception of the following subsystems:

- Gasifier and Feed
- Desulfurization
- Sulfator and Ash Feed
- Fines Combustor
- Particulate Removal

The above subsystems and others shown in Figure 2-1 for the gasification island are connected as a continuous feed and serial process. Therefore, a failure of a component in one subsystem can cause a downstream process to be shutdown. Many of the plant's non-generic components, due to their operating service, exhibit failure modes that may or may not occur as frequently at Piñon Pine than evidenced at other plants.

For example, refractory lining occurs extensively in vessels and transport piping within the gasifier, desulfurizer, and sulfator subsystems. Refractory lining may not immediately cause a failure of its associated component, but could clog a feeder in a downstream component.

Similarly, a water-to-gas heat exchanger would cause a process shutdown if water leaked through to the gas stream, but would not likely cause a shutdown if the tubes were fouled (degraded mode). These as well as other considerations were addressed in developing the R&M database.

It is important to note that data from second-generation operational IGCC plants is not available to support this study. Accordingly, MWK provided assistance in estimating R&M values for all of the Piñon Pine plant's unique components located within the gasification island (see Section 6, References 13 and 14).

As shown in the R&M spreadsheets for the various plant subsystems (see Appendix A), multiple data sources were used to establish an industry average. For some components, R&M values were based on best engineering judgment or from vendor sources. Because certain components are more critical to plant EFOR than others a UNIRAM component criticality analysis (CCA) option was performed (Table 2-1). The criticality results are provided in Section 3 along with the plant availability prediction.

SECTION 3

UNIRAM ANALYSIS RESULTS

UNIRAM models were developed for the following three plant operating modes:

- Mode 1 (Syngas operation) - Plant operates on syngas only; natgas backup is unavailable except for power island startup.
- Mode 2 (Natgas operation) - Plant operates on natgas only; syngas backup is unavailable.
- Mode 3 (IGCC operation) - Plant operates on syngas with natgas backup.

The following sections present the results of the UNIRAM analysis, identify critical components causing lost productivity, and evaluate some countermeasures for improving plant EFOR.

3.1 PIÑON PINE AVAILABILITY RESULTS

The mode 3 model is represented by the ABD shown in Figure 2-1. The mode 2 model includes only subsystems 15 through 35, and excludes the restart delay subsystems 30, 32, and 34, since there are no delays due to fuel transfer. The mode 1 model excludes only the 92.5% natgas bypass (subsystem 29). Should a gasification island failure occur during mode 1 operation, the power island must be started on natgas to return the plant to syngas operation. For the mode 1 model, it is assumed that a sufficient supply of natural gas is available to execute only the fuel transfer process.

The UNIRAM results are summarized in Table 3-1. The equivalent availability (EA) results for modes 1 and 2 agree favorably with recent data for both syngas and combined-cycle plants in cogeneration service (see Section 1.2). Although statistics are not available for second generation IGCC plants, it is appropriate to compare the results of mode 3 with baseloaded fossil-steam units. The Piñon Pine EA of 84.5% and EFOR of 13.4% compare favorably with fossil plant statistics reported by the North American Electric Reliability Council (NERC) for steam boiler generating units of all fuel types and sizes (ref. 9). Based on 1572 power units reporting to NERC, the EA and equivalent forced outage rate (EFOR) were 70% and 12% respectively. The EA for the Piñon Pine is higher than these fossil fuel plants due to significantly less scheduled outage hours. These fossil units averaged over 1000 hours per year, compared to 207 hours per year estimated for the Piñon Pine plant scheduled maintenance. This disparity is due to the fact that IGCC scheduled maintenance is integrated with the GT overhauls and inspections, and is expected to be significantly less. Piñon Pine reliability, as measured by EFOR, approximates fossil industry performance.

Table 3-1. Piñon Pine Availability Statistics by Operating Mode

Performance Statistics	Syngas Operations (mode 1)	Natgas Operations (mode 2)	IGCC Operations (mode 3)
Availability Factor (AF)	80.0%	95.2%	94.7%
Equivalent Availability (EA)	72.0%	94.8%	84.5%
Forced Outage Rate (FOR)	18.0%	3.4%	3.1%
Equivalent Forced Outage Rate (EFOR)	26.2%	3.1%	13.4%
Syngas Operating, days per year	262.9	Not applicable	189.1
Natgas Operating, days per year	Not applicable	346.0	119.2

Table 3-2 summarizes the plant subsystem availabilities. The "sulfator and ash feed", "gasifier and feed", "desulfurization" and "fines combustor" subsystems have the lowest availabilities, with MTBFs below 1,000 hours.

The failure rate (FR) of each subsystem is the reciprocal of its MTBF. By converting the MTBF for each gasification island subsystem (subsystems 1 through 14) to FR and then adding these values (see Appendix C, baseline execution run), it is determined that a syngas interruption will occur every 119 hours. The power island represented by subsystems 15 through 28 will fail every 618 hours, which in turn will cause an additional 14 outages per year to syngas operations. Power island failures will cause a 100% loss of plant capacity. Loss of syngas (a gasification island failure) will derate the plant to 90.4 MWe.

Table 3-3 summarizes the overall effect of the delays on the plant equivalent forced outage hours (EFOH) due to the three restart scenarios. The table also shows the percent contribution of each restart case to total plant EFOH. Clearly, the 47 components contributing to cold restart delays have the greatest affect on plant EFOR.

As stated in Section 1.2, the Piñon Pine project EA goal is 70% and 85% in the syngas and natgas modes respectively. The overall plant goal is 95.5%, assuming independent operation between the syngas and natgas modes. Using the modes 1 and 2 EA values, and the Piñon Pine project formula for calculating plant EA (see Section 1.2), the EA is calculated as follows:

$$EA = \frac{(8{,}760)(.72) + [8{,}760 - (.72 \times 8{,}760)]\,0.948}{8{,}760} \times 100 = 98.5\% \qquad \text{(Equation 3.1)}$$

The results of the UNIRAM analysis indicate that the Piñon Pine EA predictions exceed the project goals for the operating modes analyzed.

Table 3-2. Piñon Pine Subsystem Availability

Subsystem # - Name	Mean Down Time (MDT) hours	Mean Time Between Failure (MTBF) hours	Availability (%)
01 - Coal Handling and Receiving	*	**	99.9
02 - Coal Crushing & Transport	22.7	7688.9	99.7
04 - Oxidant Compression & Supply	16.6	4560.9	99.6
05 - Gasifier and Feed	30.2	782.0	96.3
06 - HRSGs Gasification Island	37.6	3232.9	98.9
07 - Gas Treatment & Heat Recovery	16.6	4914.9	99.7
08 - Desulfurization	15.3	569.2	97.4
09 - Sulfator & Ash Feed	26.0	566.9	95.6
10 - Fines Combustor	10.4	713.0	98.6
11 - Desulfurized Solids Removal	10.0	1400.3	99.3
12 - Particulate Removal	46.7	5803.9	99.2
13 - Solids Waste removal	19.9	**	99.9
14 - Recycle Gas	24.0	2398.5	99.0
15 - Evaporative Cooler	35.0	33200.0	99.9
17 - Gas Turbine & Generator	39.9	2006.7	98.1
18 - HRSG Power Island	57.5	6236.7	99.1
19 - BFW Makeup & Treatment	7.0	10096.0	99.9
20 - Steam Turbine & Generator	29.7	4242.7	99.3
22 - Cooling Tower	11.3	3310.6	99.7
24 - Instrument and plant Air	6.0	15031.6	99.9
25 - Electrical Distribution System	*	**	99.9
26 - Plant Controls	3.0	4431.0	99.9
27 - Waste Water Treatment	48.0	**	99.9
28 - Catastophic Events	336.0	**	99.9
30 - Hot Restart Delay	11.8	113.7	90.6
32 - Intermediate Restart Delay	43.4	485.1	91.8
33 - Cold Restart Delay	153.7	555.7	78.3

* MDT is less than one hour.
** MTBF is greater than 25 years.

Table 3-3. Affect of Restart Delays on Plant EFOH

Restart Delay Case	Delay Time (h)	# Components Affected	MTBF (h)	EFOH (h)	% of Total EFOH*
Hot Restart	142.0	144	113.7	117.4	10.2
Intermediate Restart	42.0	41	485.1	126.8	11.1
Cold Restart	11.5	47	551.7	391.1	34.1

*Percent based on a total EFOH = 1146 hours

3.2 COMPONENT CRITICALITY ANALYSIS

The UNIRAM component criticality analysis (CCA) is used to identify and rank components according to their contribution to plant EFOR. This ranking provides engineers with a quantifiable basis to evaluate EFOR reduction opportunities such as sparing to reduce downtime or redundancy to improve reliability. This ranking is accomplished as a UNIRAM run option and sets each component's availability as perfect while the remaining component's availabilities remain at their baseline values. This process is performed iteratively, one component at a time, observing the change in plant EFOR from its baseline value. The components are then ranked according to their ΔEFOR and translated into EFOH (hours per year) using the following formula:

$$EFOH = \Delta EFOR\,(PH - SOH)$$
$$EFOH = \Delta EFOR \times 8{,}553 \qquad \text{(Equation 3.2)}$$

The results of the CCA shown in Table 3-4, show EFOH values for 20 components. The EFOH values represent the downtime hours at full plant capacity (97.8-MWe) that could be saved if the component was 100% available. As explained in the preceding section, components contribute to EFOR due to their MTBF, MTTR, and restart delay times. The asterisked components in Table 3-4 indicate those components that have a significant effect on plant EFOR due to all of these combined affects. Subsystems 30, 32, and 34 represent groups of components having failure rates < 10^{-4} failures per year. Therefore, for these 44 cold restart components (subsystem 34), the average EFOH is 4.4 hours per year per component. Considering the overall contribution of restart delays to EFOH, countermeasures that reduce these delay times can prove beneficial to plant availability.

Table 3-4. Component Criticality Analysis

Subsystem #- name	Component	EFOH
09 - Sulfator & Ash Feed	Sulfator Reactor (R602)	139.8*
17 - Gas Turbine & Generator	GT Compressor	56.4
18 - HRSG Power Island	HRSG: SG801	51.4
10 - Fines Combustor	Combustor (H602)	44.5*
17 - Gas Turbine & Generator	Turbine/Bearings	34.3
11 - Desulfurized Solids Removal	Bag Filter	25.7*
17 - Gas Turbine & Generator	GT Generator	19.2
17 - Gas Turbine & Generator	GT Electrical	13.0
17 - Gas Turbine & Generator	GT Accessories/Auxillary	12.7*
05 - Gasifier and Feed	Compressor (C301)	12.0*
08 - Desulfurization	Fines Feeder (FD401)	9.1*
10 - Fines Combustor	Fines Feeder (FD503)	9.1*
20 - Steam Turbine & Generator	Generator	8.7
06 - HRSG: Gasification Island	HRSG (SG602)	8.9*
06 - HRSG: Gasification Island	HRSG Drum (D602)	8.9*
11 - Desulfurized Solids Removal	Sulfator Solids Bin (BN607)	8.0*
20 - Steam Turbine & Generator	Steam Turbine (TG801)	7.7
34 - Cold Restart Delay	44 Components having an FR < 10^{-4} failures per year	196.7
30 - Hot Restart Delay	120 Components having an FR < 10^{-4} failures per year	64.4
32 - Intermediate Restart Delay	32 Components having an FR < 10^{-4} failures per year	60.5

* Represents components that contribute to EFOH due to their MTBF, MTTR, and restart delays following their failure.

SECTION 4

IMPROVEMENT ANALYSIS

Improvements that reduce plant EFOR, even by one percentage point, translate to significant cost savings over the life of the plant. For example, if the differential replacement power cost (R) is \$70/MWh should the plant be unavailable, then a 1% reduction in EFOR results in an annual savings (S) of:

$$S\,(\$/y) = \Delta EFOR \times (PH - SOH) \times R \times MDC$$
$$S\,(\$/y) = \Delta EFOR \times (8{,}760 - 207h) \times \$70/MWh \times 97.75\ MW_e$$
$$S\,(\$/y) = 585{,}239 \qquad \text{(Equation 4.1)}$$

The present worth (P) of the annual saving (S) over an assumed 20-year plant life (t) for a 8.75% cost of capital (i) and 3% escalation (e) is:

$$P = S \times \sum_{t=0}^{t=20} \frac{(1+e)^t}{(1+i)^t}$$
$$P = S \times \sum_{t=0}^{t=20} \frac{(1+0.03)^t}{(1+0.0875)^t} \qquad \text{(Equation 4.2)}$$
$$P = S \times 12.62$$

$$P = 585{,}239 \times 12.62 = 7{,}385{,}717$$

Therefore, the present worth of a 1% EFOR reduction over 20 years is \$7,385,717. To achieve an acceptable return on investment (ROI) of 3 years, then the maximum capital cost (C) of the improvement is:

$$C = \frac{P \times ROI}{20y} \qquad \text{(Equation 4.3)}$$
$$C = \$1.1\ \text{million}$$

Therefore, improvements can be independently evaluated for benefit and screened for more detailed engineering and cost analysis. Three improvements, although hypothetical, were analyzed to estimate their annual cost savings. These improvements are addressed in the following sections.

4.1 ADDITION OF A COLD STANDBY SULFATOR REACTOR (R602) AND FINES COMBUSTOR

The sulfator represents the plants most critical single component. By introducing a second identical reactor in cold standby, the availability of the sulfator and ash feed subsystem improves and a 11.5-hour hot restart can be expected in lieu of the 142 hour cold restart, required for a single reactor. The design change, although very costly, reduces the plant EFOR from 13.4% to 12.04% which translates to (0.134 - 0.1204) × (PH - SOH) or 116 EOH saved. Using equation 4.1, the annual savings is $795,925.

Using the same approach, the addition of a second identical fines combustor in cold standby reduces the plant EFOR from 13.4% to 13.1%. Using equation 4.1, this translates to (0.134 - 0.131) × 8,553 or 25.6 EOH saved. The annual savings is $175,572.

4.2 REDUCING DELAY TIME FOR COLD RESTARTS

As shown in Appendix B, there are 47 components that, due to their MTTR's being greater than 68 hours, require a cold restart delay of 142 hours at a plant capacity of 69-MWe. If a means can be devised to reduce this delay period by one or two days, the plant EFOR can be significantly reduced. By changing the delay period in the "cold restart delay" subsystem, it was determined that the EFOR reduces to 13.1% for a one-day decrease in delay time. For a two-day decrease, the EFOR reduces to 12.8%. These one and two-day reductions provide an annual savings of $175,572 and $351,143 respectively.

The technical feasibility of implementing such improvements and their capital cost would need to be determined to assess cost benefit. Other improvements that can be practically implemented at the suggestion of FW USA and MWK can be evaluated using this approach.

SECTION 5

CONCLUSIONS AND RECOMMENDATIONS

The objective of this study was to assess the projected availability of the Piñon Pine plant. The results serve as a benchmark to identify weaknesses in the design or highlight R&M issues that warrant additional evaluations. Based on the UNIRAM analysis, the project EA goals are achievable subject to the operational conditions and assumptions stated herein. Due to the serial configuration of the gasification island design, there are numerous single-point failures that will result in loss of syngas production and necessitate transfer to natgas. The serial design results in a high frequency of syngas production failures which, when coupled to restart delays, extends the time the plant must operate on natural gas from 93 days per year (project goal) to 119 days per year.

Of the 232 components represented in the plant model, 47 have MTTRs that exceed 68 hours and require a cold restart delay time of 142 hours. These cold restart delays account for 34% of the total annual plant EFOH (1146 hours), compared to 10% for the 144 components that are subject to hot restart delay time of 11.5 hours. Therefore, improvements that reduce the frequency of plant failures and also reduce MTTRs below 68 hours afford the best opportunity for plant EFOR reduction.

The analysis also suggests the following additional conclusions:

- The sulfator reactor is the plant's most critical component due to the combined effects of its reliability and downtime due to cold restart delays.
- Due to the affects of MTTR and restart delays on plant EFORs, an aggressive maintenance policy and preventive maintenance program is necessary to achieve the predicted availability performance.
- The IGCC affords an excellent opportunity to minimize total plant shutdown time for scheduled maintenance by integrating gasification island maintenance with GT inspections and overhauls. The 207 equivalent outage hours per year predicted for scheduled maintenance is less than one-fifth the hours reported by the NERC Generating Availability Data System for fossil steam units.
- Introducing redundancy on selected critical components, and reducing restart delay times afford significant EFOR reduction opportunities. The UNIRAM model can be used to support subsequent availability improvement and cost benefit analysis.

- The plant EFOR is significantly affected by components within the gasifier, desulfurization, sulfator, and fines combustor subsystems.

Based on the findings presented herein, availability improvement efforts should be directed toward improving the reliability or reducing the MTTR of components that lead to cold restarts (see the components noted in Section B.3.1 of Appendix B). Also any component denoted with an asterisk in Sections B.1.1, B.2.1, or B.3.1 should be examined. These asterisked components have failure rates greater than 10^{-4} failures per year. This examination should:

- Identify dominate failure modes, method of detection, and compensatory actions to mitigate their affect on plant EFOR.
- Consider design modifications that reduce MTTR such as installing bypasses around valves, sparing replaceable assemblies, improving accessibility for repair, or devising methods for accelerating cool-down times for hot-section components.
- Develop a reliability-centered maintenance plan for critical components. The plan is needed to institute a predictive maintenance program for the plant. Predictive (condition-based) maintenance programs provide plant operations with the "real-time" data and computer-based resources needed to detect incipient failures or degraded conditions within critical plant equipment. Such a program could save thousands of dollars per year in maintenance costs and avoid costly unplanned outages.
- Identify the requirements for condition-monitoring instrumentation and real-time data trending to detect incipient failure modes within the gasification island's gas treatment cooling, desulfurization, and various critical rotating equipment (e.g., recycle gas compressor, boiler feedwater pump).

The scheduled maintenance plan presented herein is based on the assumption that the annual gasification island turnaround can be accomplished within 3 days. A study is recommended to define the tasks, frequency, man-hour requirements, and spare parts needed for the annual turnaround and to develop a preventive maintenance plan. This study will help assure that plant downtime is minimized and that procedures are in place to effectively maintain the plant and improve its reliability.

SECTION 6

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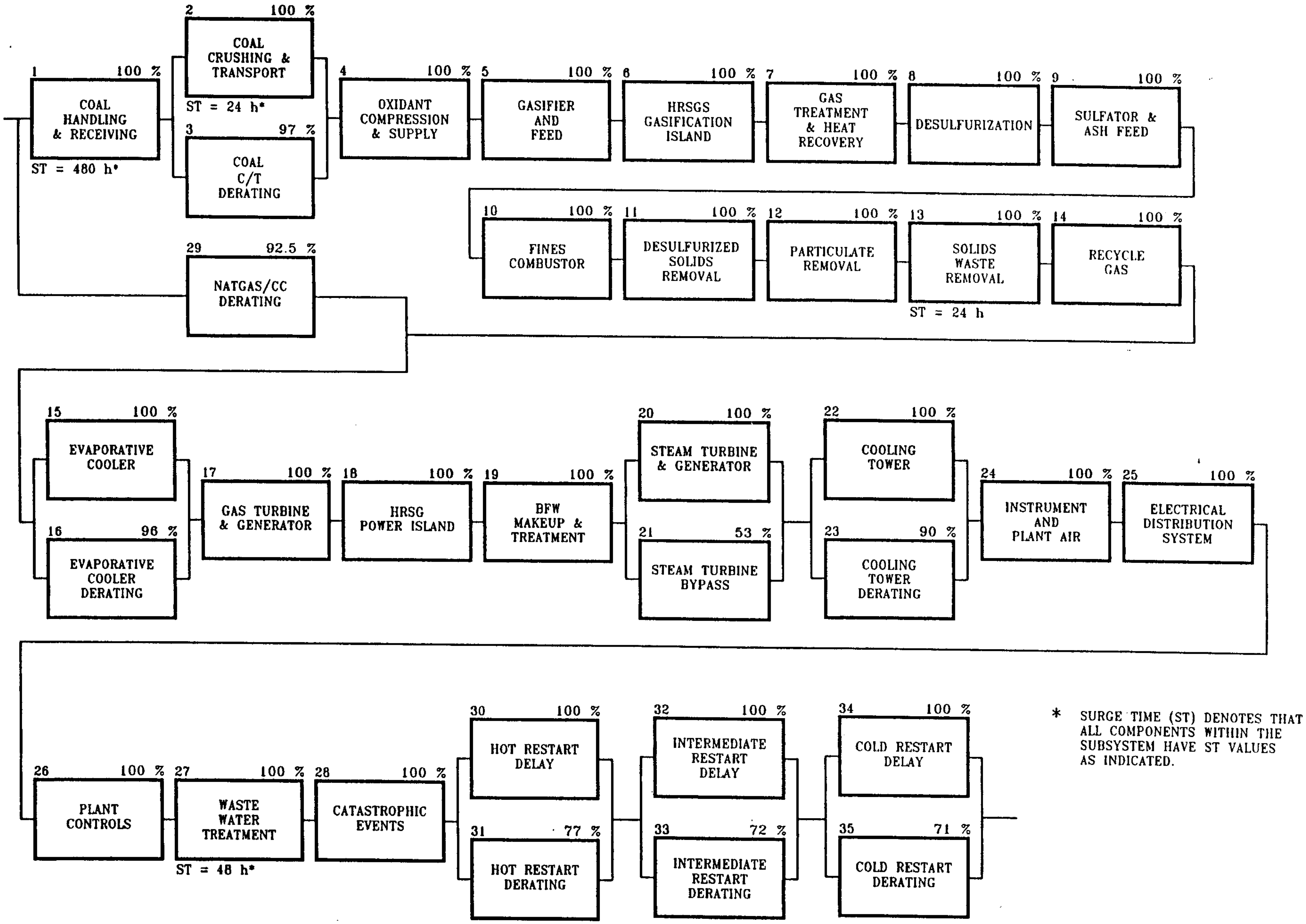


Piñon Pine Availability Block Diagram

APPENDIX A

SUBSYSTEM DESCRIPTIONS, FAULT TREES AND COMPONENT DATA

This Appendix contains the subsystem descriptions, fault tree analysis, and the component R&M data that were utilized in the analysis of the Piñion Pine plant.

SUBSYSTEM DESCRIPTION DATA SHEET

1. Data Sheet Number: 1

2. Description:

Subsystem Name:	Coal Handling & Receiving
ABD I.D, Number:	1
Plant Capacity (%):	100
Plant Area:	Solids Receiving and Grinding (100)

3. Comments:

The function of the Coal Receiving and Handling subsystem is to represent the receiving, handling and storage of the raw coal. This subsystem description encompasses the first part of Area 100, as described in 3.3.1.1 of the Technical Baseline. A brief process description, as it applies to the UNIRAM model, is given below:

The Coal Receiving and Handling subsystem contains eight components, and has a capacity state of 100%. This subsystem is governed by a surge time. The surge time, as it is presented in the UNIRAM model, is used to account for the effects of storage components within the subsystem. In this case, the Coal Storage Dome (X-100), is sized to store approximately 20 day's requirement of coal. In the model this storage component has a pronounced effect on the entire subsystem thus providing each component with a surge time of 480 hours. Due to the effects of this surge time, the subsystem attains a very high availability.

4. Availability:

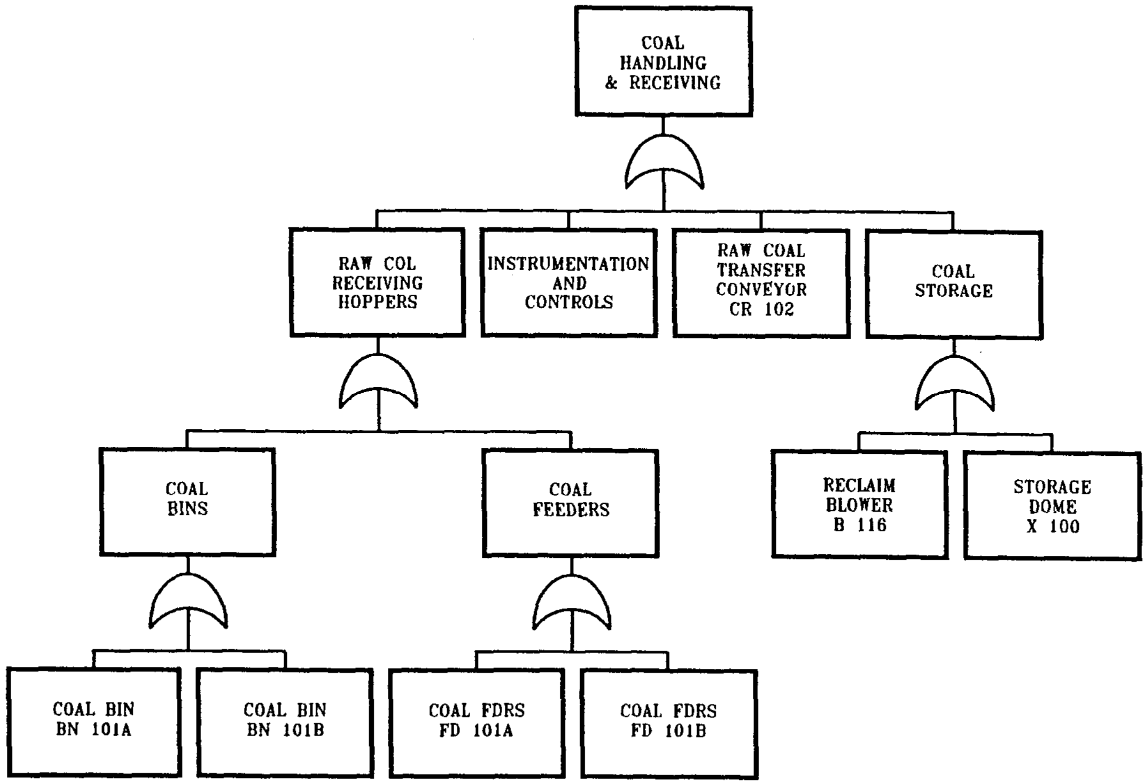
Mean Time Between Failures (h): 100,000,000.0
Mean Downtime (h): 0.01
Availability (%): 1.00

5. Critical Components:

No critical components are identified that have a significant affect on EFOR.

SUBSYSTEM (1): COAL HANDLING AND RECEIVING

COMPONENT	DESCRIPTION	ID #	FAILURE RATE	Pinon Pine Plant MTBF	MTTR	MDT	Industry Data MTBF	MDT	SOURCE
HOPPERS	two receiving bins	BN-101 A/B (2)	2.41E-05	41512	20	20	12500	74.24	Reference 1
							9986	12.5	Reference 2
							9100	11	Reference 5
							52560	5	Reference 6
FEEDERS	belt type	FD-101 A/B (2)	3.43E-05	29193	16	16	17520	4.84	Reference 1
							17520	18	Reference 2
							17500	7	Reference 5
							52560	5	Reference 6
CONVEYOR	belt type	CR-102	6.23E-05	16053	16	16	17520	5.09	Reference 1
							17520	18	Reference 2
							17500	32	Reference 5
							13140	7.6	Reference 6
STORAGE DOME	completely closed	X-100	1.00E-06	999999	20	20	NA	NA	Reference 6
I & C CONTROLS			6.60E-05	15150	6	6	15150	6	Reference 6
RECLAIM BLOWER		B-116	6.00E-06	166666	28	28	166666	28	Reference 1



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SUBSYSTEM DESCRIPTION DATA SHEET

1. Data Sheet Number: 2

2. Description:

Subsystem Name:	Coal Crushing and Transport, (Coal C/T Derating)
ABD I.D, Number:	2, (3)
Plant Capacity (%):	100, (97)
Plant Area:	Solids Receiving and Grinding (100)

3. Comments:

The function of the Coal Crushing and Transport subsystem is to represent the coal crushing, screening and transport of the raw coal. This subsystem description encompasses the remaining parts of Area 100, as described in sections 3.3.1.2 and 3.3.1.3. A brief description, as it applies to the UNIRAM model is given below:

The Coal Crushing and Transport subsystem contains 15 components, and has a capacity state of 100%. If any component fails, the plant has the capability to continue operation at a derated capacity of 97%. This is accomplished by a reduction in feed rate and the introduction of natgas spiking. This subsystem contains one set of redundant coal feeders. Included in the modeling is a 24 hour surge time due to the one day storage time associated with the Coal Silo (BN-105), and six day surge time associated only with the Limestone Silo (BN-107).

4. Availability:

Mean Time Between Failures (h): 7,688.9
Mean Downtime (h): 22.7
Availability (%): 99.7

5. Critical Components:

No critical components are identified that have a significant affect on EFOR.

SUBSYSTEM (2): COAL CRUSHING AND TRANSPORT

COMPONENT	DESCRIPTION	ID #	FAILURE RATE	Pinon Pine Plant MTBF	Pinon Pine Plant MTTR	Pinon Pine Plant MDT	Industry Data MTBF	Industry Data MDT	SOURCE
STACKING CONVEYOR		CR-118	5.22E-05	19158	30	30	28470	58	Reference 1
							17520	18	Reference 2
							17500	32	Reference 5
							13140	7.6	Reference 6
COAL PILE RECLAIMER		RL-101	3.11E-05	32120	10	10	26280	10	Reference 1
							17520	18	Reference 2
							52560	2.1	Reference 6
COLLECTING CONVEYOR		CR-105	6.23E-05	16053	16	16	17520	4.84	Reference 1
							17520	18	Reference 2
							17500	32	Reference 5
							13140	7.6	Reference 6
FEEDER	vibratory	FD-114	5.71E-05	17510	8	8	17520	2.8	Reference 2
							17500	3	Reference 5
							17520	18	Reference 6
DIVERTER		DV-105	5.71E-05	17500	3	3	17500	3	Reference 5
SCREEN	dual deck vibrating	SE-104	3.54E-05	28280	18	18	26280	18	Reference 1
OVERSIZE CONVEYOR	elevated	CR-114	6.23E-05	16053	16	16	17520	14	Reference 1
							17520	18	Reference 2
							17500	32	Reference 5
							13140	7.6	Reference 6
OVERSIZE FEEDER		FD-117	5.71E-05	17510	8	8	1130	7.75	Reference 1
							17520	2.8	Reference 2
							17500	7	Reference 5
							17520	18	Reference 6
CRUSHER		SR-102	1.14E-04	8760	28	28	8760	28	Reference 1
							486.7	1.5	Reference 2
							8760	7	Reference 6
SIZED COAL CONVEYOR		CR-115	6.23E-05	16053	16	16	17520	4.84	Reference 1
							17520	18	Reference 2
							17500	32	Reference 5
							13140	7.6	Reference 6
INSTRUMENTATION AND CONTROLS			6.60E-05	15150	6	6	15150	6	Reference 6
STORAGE SILOS (RECEIVING BINS)		BN-107, BN-108 (2)	1.05E-04	9495	4	4	8000	3	Reference 1
							10989	4	Reference 5
EMERG HOPPER		BN108	2.41E-05	41512	20	20	41512	20	Reference 1
EMERG FEEDER			5.71E-05	17510	8	8	17510	8	Reference 2

SUBSYSTEM DESCRIPTION DATA SHEET

1. Data Sheet Number: 3

2. Description:

Subsystem Name: Oxidant Compression and Supply
ABD I.D, Number: 4
Plant Capacity (%): 100
Plant Area: Oxidant Compression and Supply (200)

3. Comments:

The function of the Oxidant Compression and Supply subsystem is to represent the section of the plant that provides air to the gasifier, air for regeneration of the desulfurization sorbent, air for coal and limestone feed pressurization and transport air for feeding coal and limestone into the gasifier. This subsystem description encompasses all of Area 200, as described in section 3.2.2 of the Technical Baseline. A brief description, as it applies to the UNIRAM model, is given below:

The Oxidant Compression and Supply subsystem contains 11 components, and has a capacity state of 100%. This subsystem is not governed by a surge time and has no derated capacity states. A failure of any single component will cause a gasification island shut down.

4. Availability:

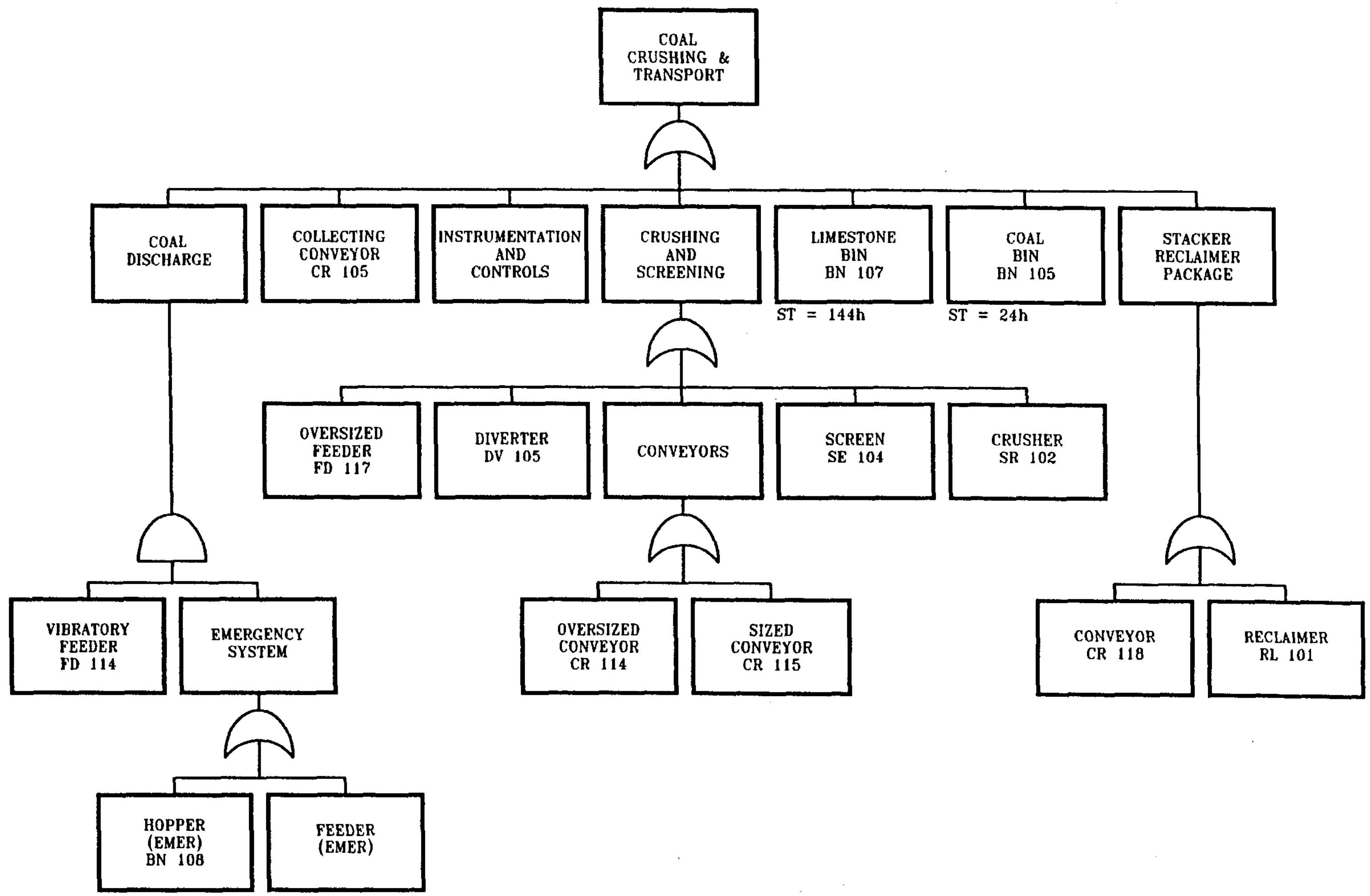
Mean Time Between Failures (h): 4,560.9
Mean Downtime (h): 16.6
Availability (%): 99.6

5. Critical Components:

No critical components are identified that have a significant affect on EFOR.

SUBSYSTEM (4): OXIDANT COMPRESSION AND SUPPLY

COMPONENT	DESCRIPTION	ID #	FAILURE RATE	Pinon Pine Plant			Industry Data		SOURCE
				MTBF	MTTR	MDT	MTBF	MDT	
TRIM COOLER	cool H2O for final gas cool	E202	1.03E-05	97000	21	57	97000	57	Reference 1
							97000	57	Reference 11
CONTROL VALVES			3.69E-05	27100	5	5	17500	4	Reference 5
							90900	5	Reference 6
COMPRESSORS	boost air compressor	C201	3.81E-05	26280	40	76	33288	40	Reference 1
							26280	76	Reference 11
							26280	42	Reference 2
TRANSPORT AIR COOLER	cool H2O used to cool air	E204	1.03E-05	97000	21	57	97000	57	Reference 1
							97000	57	Reference 11
KNOCKOUT DRUM	remove cond. H2O from air	D201	1.10E-05	91000	20	56	91000	20	Reference 1
							91000	56	Reference 11
AIR PRECOOLER	heat BFW	E203 S1/S2 (2)	1.03E-05	97000	21	57	97000	57	Reference 1
							97000	57	Reference 11
AIR RECUPERATOR	reheats comp. air for R301	E201 S1/S2 (2)	1.03E-05	97000	21	57	97000	57	Reference 1
							97000	57	Reference 11
COMPRESSOR BLEED VALVE			5.45E-06	183486	4	8	183486	4	Reference 7
							183486	8	Reference 11
EXTRACTION AIR CONTROLS			6.60E-05	15150	6	12	15150	6	Reference 6
							15150	12	Reference 11



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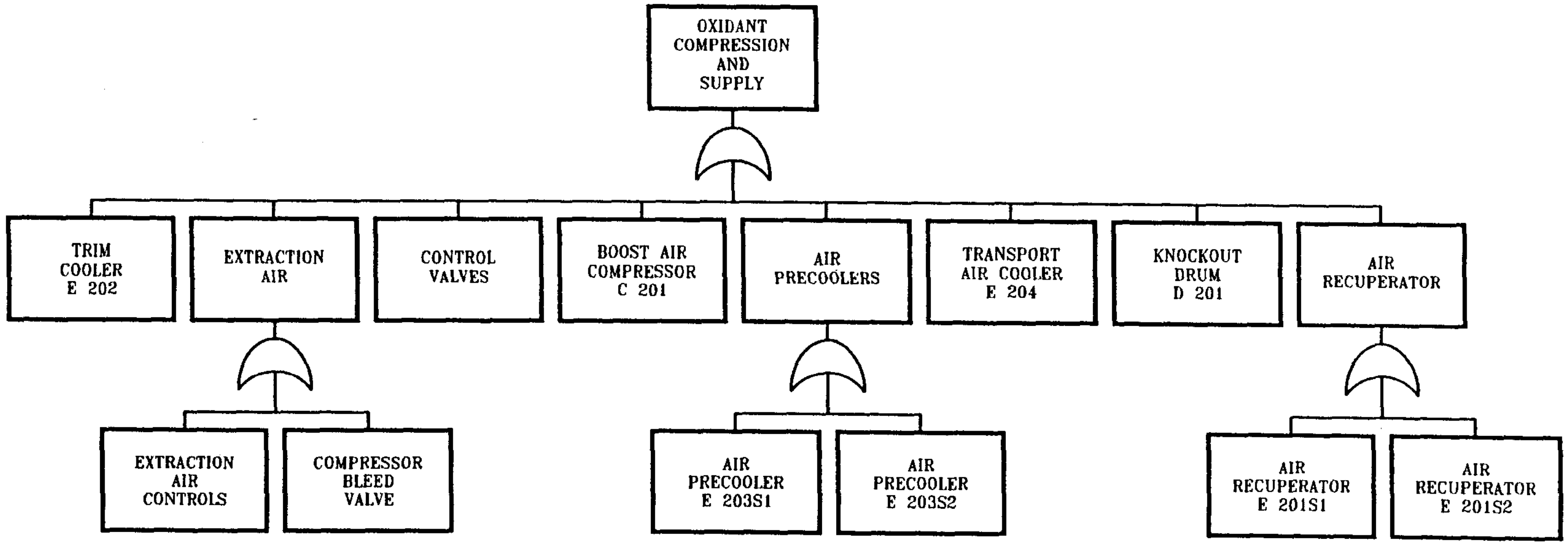

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SUBSYSTEM DESCRIPTION DATA SHEET

1. Data Sheet Number: 4

2. Description:

Subsystem Name: Gasifier and Feed
ABD I.D, Number: 5
Plant Capacity (%): 100
Plant Area: Coal gasification (300)

3. Comments:

The function of the Gasifier and Feed subsystem is to represent the section of the plant that contains the solids feed system and the gasifier with its associated cyclone. This subsystem description encompasses Area 300, as it is described in 3.2.1 of the Technical Baseline. A brief process description, as it applies to the UNIRAM model, is given below:

The Gasifier and Feed subsystem contains 22 components, and has a capacity state of 100%. The hoppers, (BN-301/2/3), have surge times of less than one hour. The subsystem contains a set of redundant extraction steam controls, which supply steam to the gasifier. A failure of any single component, with the exception of a single extraction steam control failure, will cause a gasification island shut down.

4. Availability:

Mean Time Between Failures (h):782.0
Mean Downtime (h): 30.2
Availability (%): 96.3

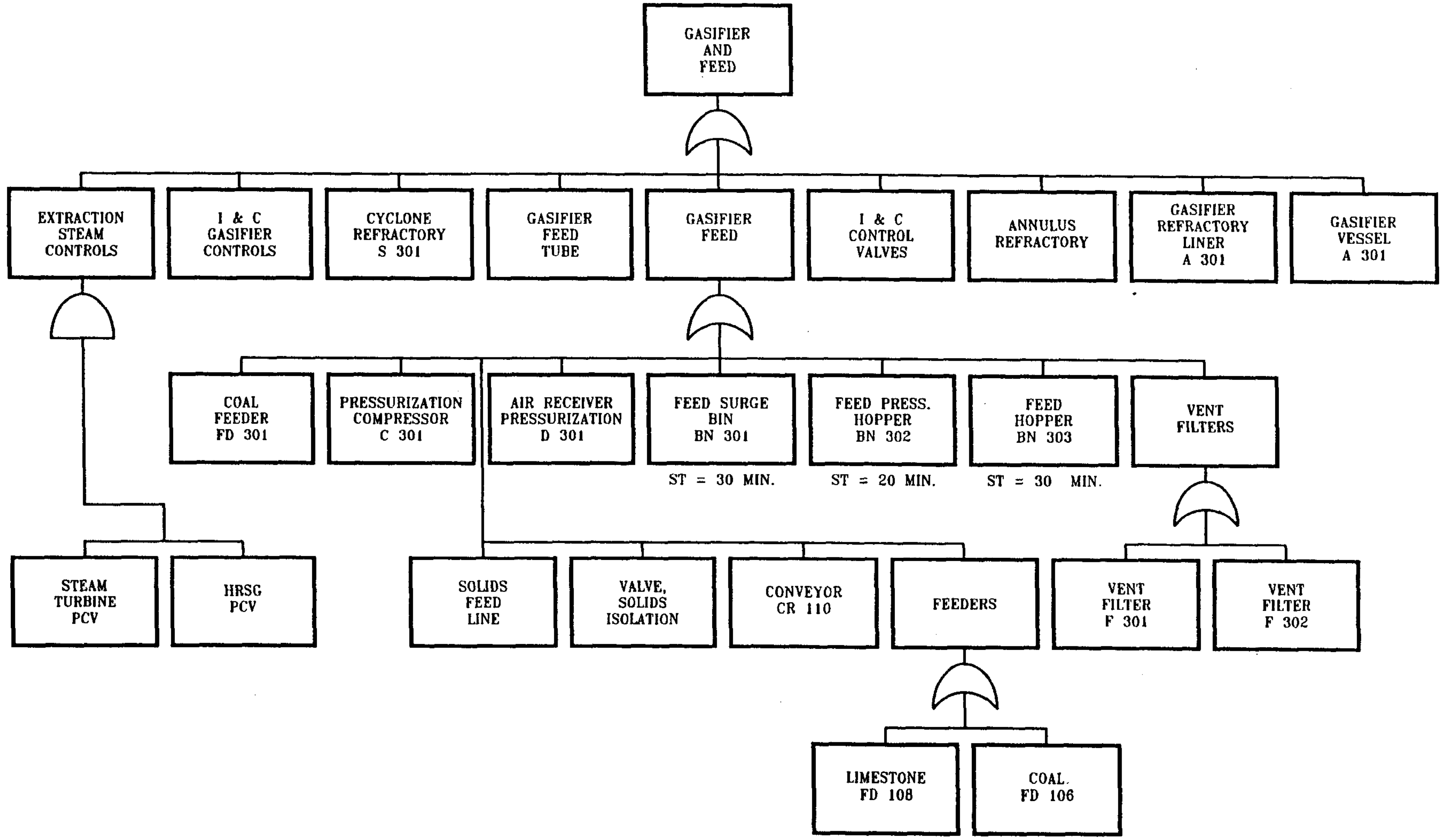
5. Critical Components:

Component	Equivalent Outage* Hours Downtime
C-301, Intermediate Restart	10.3
Gasifier refractory, R-301	3.6
Annulus Refractory	3.2
Feed Bin (BN-301), Hot Restart	2.1
Vent Filter (F-302), Hot Restart	1.8
Compressor, C-301	1.7
Gasifier Feed Tube	1.3

* Calendar hours lost at 97.8-MWe

SUBSYSTEM (5): GASIFIER AND FEED

COMPONENT	DESCRIPTION	ID #	FAILURE RATE	Pinon Pine Plant MTBF	Pinon Pine Plant MTTR	Pinon Pine Plant MDT	Industry data MTBF	Industry data MDT	SOURCE
GASIFIER REFRACTORY LINER	air blown, fluidized bed	R301	9.51E-06	105120	1110	1242	40000	252	Reference 5
							105120	1242	Reference 13
CYCLONE REFRACTORY LINER		S301	1.90E-05	52560	120	252	40000	120	Reference 5
							52560	252	Reference 13
GASIFIER FEED TUBE	part of gasifier		7.61E-05	13140	52	184	8760	96	Reference 5
							13140	184	Reference 13
ANNULUS REFRACTERY	part of gasifier		1.90E-05	52560	490	622	10860	5	Reference 1
							8760	24	Reference 5
							52560	622	Reference 13
COAL FEEDER		FD301	5.71E-05	17520	8	16	26280	16	Reference 1
							163	80	Reference 3
							1610	4	Reference 5
							17520	16	Reference 13
PRESSURIZATION COMPRESSOR		C301	1.67E-04	6000	30	66	15140	34	Reference 1
							90000	168	Reference 5
							6000	66	Reference 14
AIR RECEIVER		D301	1.11E-05	90000	25	157	91000	20	Reference 1
							40000	32	Reference 5
							90000	157	Reference 13
FEED SURGE BIN		BN301	1.56E-04	6410	2	4	6757	24	Reference 3
							10989	4	Reference 5
							6410	4	Reference 13
FEED PRESSURE HOPPER		BN302	9.12E-05	10970	7	14	6061	25	Reference 3
							4600	4	Reference 5
							10970	14	Reference 13
FEED HOPPER		BN303	1.07E-04	9320	8	16	5464	25	Reference 3
							7500	4	Reference 5
							9320	16	Reference 13
FILTER		F302	1.31E-04	7620	2	4	13140	4	Reference 5
							7620	4	Reference 13
EXTRACTION STEAM CONTROLS	Steam Turbine PCV HRSG PCV	(2)	2.87E-06	348432	4	8	348432	8	Reference 10
							348432	8	Reference 13
GASIFIER CONTROLS			6.60E-05	15150	3	6	15150	6	Reference 6
							15150	6	Reference 13
GASIFIER VESSEL		R301	4.57E-06	219000	360	492	150800	80	Reference 5
							219000	492	Reference 13
CONTROL VALVES	quantity = 2		3.40E-05	29411	4	8	29411	8	Reference 10
							29411	8	Reference 13
LIMESTONE AND COAL FEEDERS		FD106, FD1 (2)	5.83E-05	17150	8	16	278	24	Reference 1
							8760	43.3	Reference 2
							1610	4	Reference 5
ELEVATING CONVEYOR		CR110	6.23E-05	16053	8	16			EPRI handbk
									EPRI analysis
									MECSI
FILTER		F301	7.61E-05	13140	6	12	13140	12	Reference 13
SOLIDS FEED LINE			3.81E-05	26280	3	6	26280	6	Reference 13
VALVE, SOLIDS ISOLATION		TV-0043	3.81E-05	26280	3	135	26280	135	Reference 13



FAULT TREE: [5]

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960627-HB-F105

SUBSYSTEM DESCRIPTION DATA SHEET

1. Data Sheet Number: 5

2. Description:

Subsystem Name: HRSGs Gasification Island
ABD I.D, Number: 6
Plant Capacity (%): 100
Plant Area: Gas Stream Heat Recovery (400)

3. Comments:

The function of the HRSGs Gasification Island subsystem is to represent the section of the plant that pertains to the heat recovery section of the gasification island. This subsystem description encompasses part of Area 400, as it is described in paragraphs 4 and 5 of section 3.2.3 of the Technical Baseline. A brief process description, as it applies to the UNIRAM model, is as follows:

The HRSGs Gasification Island subsystem contains 7 components, and has a capacity state of 100%. This subsystem has no surge time. Included in this subsystem are the High Pressure Phosphate Pumps (P-1211A/B/C). These pumps share a common spare (P-1211 C). Any combination of two pump failures will directly cause a gasification island shut down.

4. Availability:

Mean Time Between Failures (h): 3,232.9
Mean Downtime (h): 37.6
Availability (%): 98.9

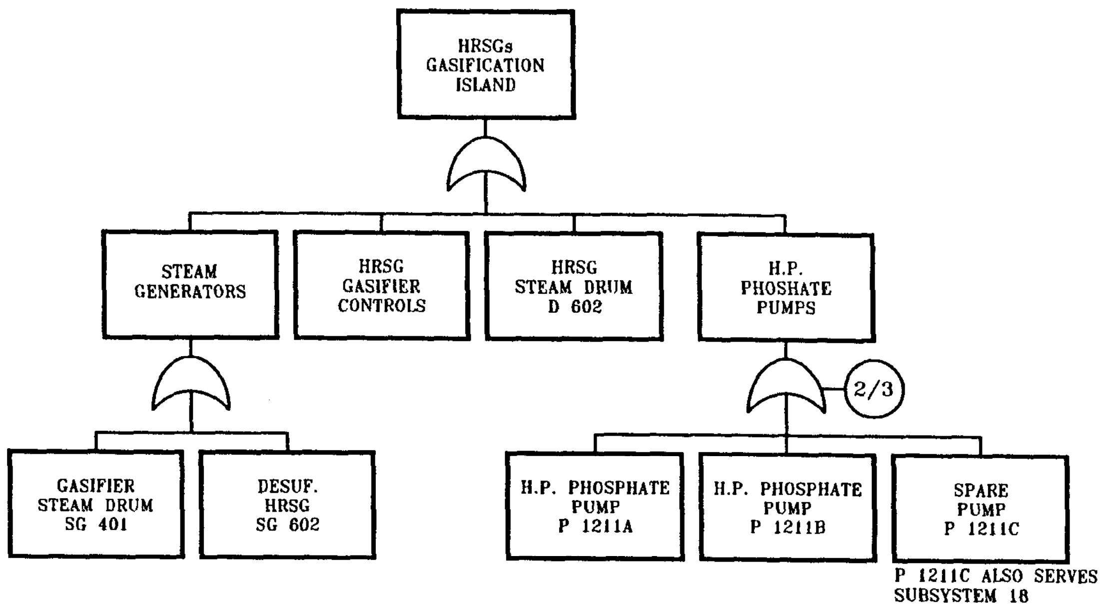
5. Critical Components:

Component	Equivalent Outage* Hours Downtime
HRSG (SG-602), Intermediate Restart	7.0
HRSG Drum (D-602), Intermediate Restart	7.0
HRSG, SG-602	1.9
HRSG Drum, D-602	1.9

* Calendar hours lost at 97.8-MWe

SUBSYSTEM (6): GASIFICATION ISLAND HRSGs

COMPONENT	DESCRIPTION	ID #	FAILURE RATE	Pinon Pine Plant MTBF	Pinon Pine Plant MTTR	Pinon Pine Plant MDT	Industry Data MTBF	Industry Data MDT	SOURCE
GASIFIER STEAM DRUM	supplies BFW for the gas coolers	SG401	1.50E-05	66667	16	32	91000	20	Reference 1
							33333	40	Reference 3
							66667	32	Reference 13
HRSG STEAM DRUM		D602	1.14E-04	8760	48	84	91000	20	Reference 1
							4380	4	Reference 14
H.P. PHOSPHATE PUMPS		P1211 A/B/C (3)	1.16E-04	8652	4.8	4.8	8652	4.8	Reference 6
HRSG GASIFIER CONTROLS			6.60E-05	15150	6	6	15150	6	Reference 6
HEAT RECOVERY STEAM GENERATOR		SG602	1.14E-04	8760	48	84	15140	105	Reference1
							4380	4	Reference 14



FAULT TREE: [6]

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960627-HB-F106

SUBSYSTEM DESCRIPTION DATA SHEET

1. Data Sheet Number: 6

2. Description:

Subsystem Name:	Gas Treatment and Heat Recovery
ABD I.D, Number:	7
Plant Capacity (%):	100
Plant Area:	Gas Stream Heat recovery (400)

3. Comments:

The function of the Gas Treatment and Heat Recovery subsystem is to represent the cooling of the main product gas from the gasifier as well as cooling of the recycle gas. This subsystem description encompasses the Area 400, as described in section 3.2.3 of the Technical Baseline. A brief description, as it applies to the UNIRAM model, is given below:

The Gas Treatment and Heat Recovery subsystem contains six components, and has a capacity state of 100%. This subsystem has no surge time, and contains no redundant components. A failure of any single component will cause a gasification island shut down.

4. Availability:

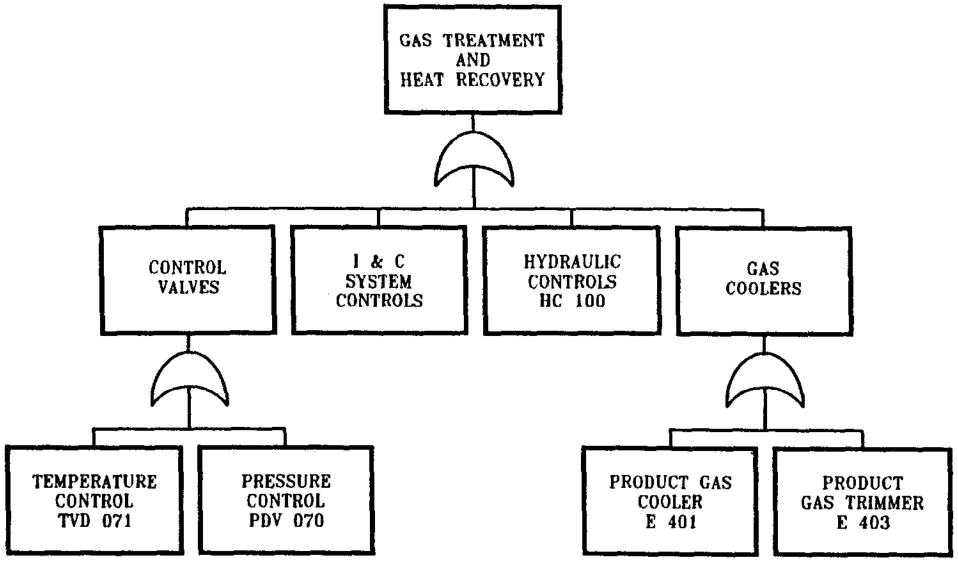
Mean Time Between Failures (h): 4,914.9
Mean Downtime (h): 16.6
Availability (%): 99.7

5. Critical Components:

No critical components are identified that have a significant affect on EFOR.

SUBSYSTEM (7): GAS TREATMENT AND HEAT RECOVERY

COMPONENT	DESCRIPTION	ID #	FAILURE RATE	Pinon Pine Plant MTBF	Pinon Pine Plant MTTR	Pinon Pine Plant MDT	Industry Data MTBF	Industry Data MDT	SOURCE
HYDRAULIC CONTROL MODULE		HC100	1.57E-05	63735	3	6	63735	5	Reference 4
							63735	6	Reference 13
PRODUCT GAS COOLER	cools gas from S301	E401	2.28E-05	43800	60	192	97000	57	Reference 1
							43800	192	Reference 14
PRODUCT GAS TRIMMER	cools gas from S301	E403	2.28E-05	43800	60	192	97000	57	Reference 1
							43800	192	Reference 14
VALVE	temp. control differentia	TV0071	3.81E-05	26280	6	138	26280	138	Reference 13
VALVE	pressure control	PDV070	3.81E-05	26280	6	138	26280	138	Reference 13
I&C	system controls		6.60E-05	15150	2	4	15150	4	Reference 13



FAULT TREE: [7]

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960627-HB-F107

SUBSYSTEM DESCRIPTION DATA SHEET

1. Data Sheet Number: 7

2. Description:

Subsystem Name: Desulfurization
ABD I.D, Number: 8
Plant Capacity (%): 100
Plant Area: Desulfurization (600)

3. Comments:

The function of the Desulfurization subsystem is to represent the components related to the actual desulfurization process of the product fuel gas. This subsystem description encompass the first part of Area 600, as described in section 3.2.4 of the Technical Baseline. A brief process description, as it applies to the UNIRAM model, is given below:

The Desulfurization subsystem contains 19 components, and has a capacity state of 100%. This subsystem has no redundant components. The Receiver Hopper (BN-610) has a surge time is 480 hours. A failure of any single component will cause a gasification island shut down.

4. Availability:

Mean Time Between Failures (h): 569.2
Mean Downtime (h): 15.3
Availability (%): 97.4

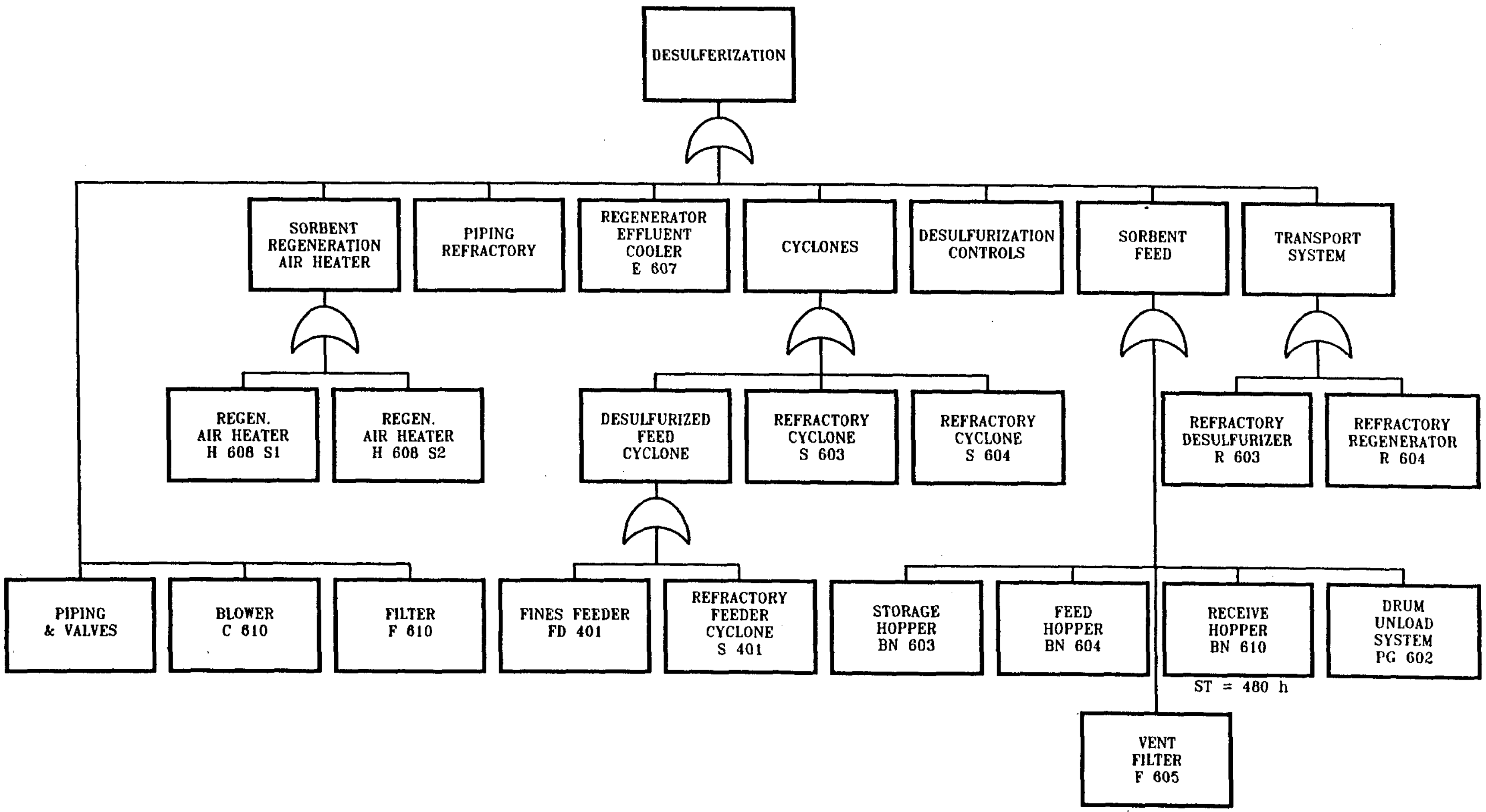
5. Critical Components:

Component	Equivalent Outage* Hours Downtime
Fines Feeder (FD-401), Hot Restart	8.3
Filter (F-610), Hot Restart	6.7
Bin (BN-610), Hot Restart	2.1
Refractory Cyclone, S-401	1.2
Refractory Cyclone, S-603	1.2
Refractory Cyclone, S-604	1.2
Desulfurizer Refractory, R-603	1.2
Regenerator Refractory, R-604	1.2
Fines Feeder, FD-401	0.8

* Calendar hours lost at 97.8-MWe

SUBSYSTEM (8): DESULFURIZATION

COMPONENT	DESCRIPTION	ID #	FAILURE RATE	Pinon Pine Plant MTBF	Pinon Pine Plant MTTR	Pinon Pine Plant MDT	Industry Data MTBF	Industry Data MDT	SOURCE
SORBENT REGENERATION AIR HEATERS		H608 S1/S2 (2)	3.00E-05	33288	22	44	33288	22	Reference 1
							33288	44	Reference 13
REGENERATOR EFFLUENT COOLER		E607	2.85E-05	35055	60	192	35055	60	Reference 5
							35055	192	Reference 13
REFRACTORY CYCLONE		S603	1.90E-05	52560	180	312	40000	120	Reference 5
							52560	180	Reference 13
REFRACTORY CYCLONE		S604	1.90E-05	52560	180	312	40000	120	Reference 5
							52560	180	Reference 13
DESULFURIZED FEED CYCLONE		S401	1.90E-05	52560	180	312	40000	120	Reference 5
							52560	180	Reference 13
FINES FEEDER		FD401	6.21E-04	1610	4	8	1610	4	Reference5
							13140	8	Reference 14
I&C CONTROLS			6.60E-05	15150	3	6	15150	6	Reference 6
							15150	6	Reference 13
STORAGE HOPPER		BN603	3.81E-05	26280	3	6	6757	24	Reference 3
							10989	4	Reference 5
							26280	6	Reference 13
FEED HOPPER		BN604	1.22E-04	8224	5	10	6061	25	Reference 3
							4600	4	Reference 5
							8224	10	Reference 13
VENT FILTER		F605	7.61E-05	13140	4	8	13140	4	Reference 5
							13140	8	Reference 13
RECEIVE HOPPER		BN610	1.54E-04	6482	5	5	5464	25	Reference 3
							7500	4	Reference 5
DRUM UNLOAD SYSTEM		PG602	7.50E-06	133333	13	13	NA	NA	
DESULFURIZER REFRACTORY		R603	1.90E-05	52560	180	312	26280	120	Reference 1
							52560	312	Reference 13
REGENERATOR REFRACTORY		R604	1.90E-05	52560	180	312	26280	120	Reference 1
							52560	312	Reference 13
PIPING REFRACTORY			9.51E-06	105120	180	312	40000	252	Reference 5
							105120	312	Reference 13
PIPING, VALVES SOLIDS			3.81E-05	26280	8	140	26280	140	Reference 13
BLOWER	transport air	C610	9.51E-05	10520	4	8	10520	8	Reference 13
FILTER	blower	F610	5.00E-04	2000	0.5	1	2000	1	Reference 13



FAULT TREE: [8]

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960627-HB-F108

SUBSYSTEM DESCRIPTION DATA SHEET

1. Data Sheet Number: 8

2. Description:

Subsystem Name: Sulfator and Ash Feed
ABD I.D, Number: 9
Plant Capacity (%): 100
Plant Area: Desulfurization (600)

3. Comments:

The function of the Sulfator and Ash Feed subsystem is to represent the section of the plant that contains the ash removal and sulfator process. This subsystem description encompasses Area 600, as it is described in section 3.2.4 of the Technical Baseline. A brief description, as it applies to the UNIRAM model, is given below:

The Sulfator and Ash Feed subsystem contains 19 components, and has a capacity state of 100%. This subsystem includes the ash feed components to the sulfator. The hoppers, (BN-501, 502, 508), have surge times of less than one minute. This subsystem contains no redundant components. A failure of any single component will cause a gasification island shut down.

4. Availability:

Mean Time Between Failures (h): 566.9
Mean Downtime (h): 26.0
Availability (%): 95.6

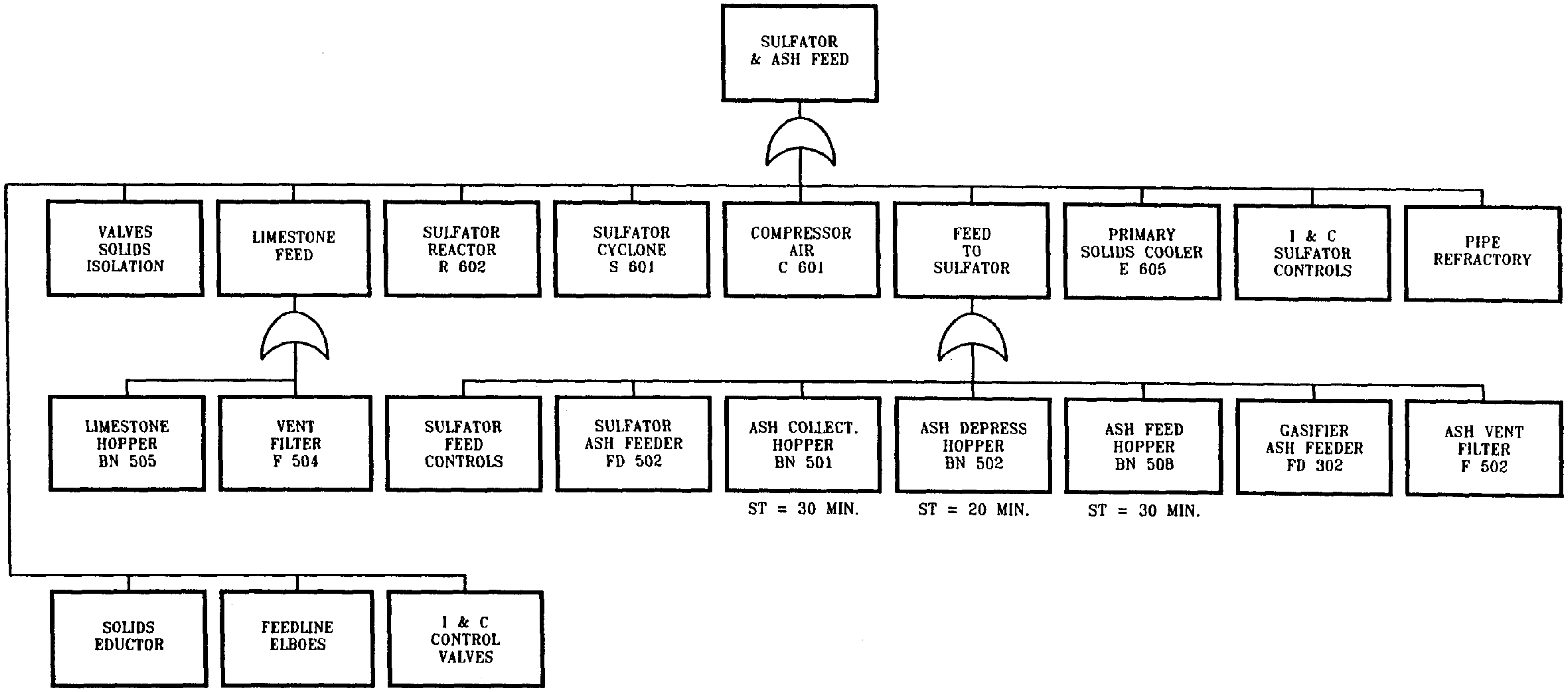
5. Critical Components:

Component	Equivalent Outage* Hours Downtime
Sulfator Reactor, Cold Restart	196.7
Sulfator Reactor, R-602	12.1
Ash Collector Hopper (BN-501), Inter. Restart	7.0
Solids Eductor, Intermediate Restart	7.0
Ash Feed Hopper (BN-501), Inter. Restart	6.6
Vent Filter, F-501	0.5
Sulfator Cyclone, S-601	0.5

* Calendar hours lost at 97.8-MWe

SUBSYSTEM (9): SULFATOR AND ASH FEED

COMPONENT	DESCRIPTION	ID #	FAILURE RATE	Pinon Pine Plant MTBF	Pinon Pine Plant MTTR	Pinon Pine Plant MDT	Industry Data MTBF	Industry Data MDT	SOURCE
LIMESTONE HOPPER		BN505	1.19E-04	8423	4	8	6061	25	Reference 3
							4600	4	Reference 5
							8423	8	Reference 13
VENT FILTER	hopper vent	F504	7.61E-05	13140	4	8	13140	4	Reference 5
							13140	8	Reference 13
I&C CONTROLS			6.60E-05	15150	3	6	15150	6	Reference 6
							15150	6	Reference 13
SULFATOR REACTOR		R602	5.88E-04	1700	60	192	1564	52	Reference 8
							17520	79	Reference 1
							1700	192	Reference 14
SULFATOR CYCLONE	refractory	S601	1.14E-05	87600	120	252	40000	120	Reference 5
							87600	252	Reference 13
AIR COMPRESSOR	process air	C601	3.81E-05	26280	21	42	26280	42	Reference 1
							26280	42	Reference 13
SULFATOR ASH FEEDER		FD502	5.71E-05	17520	8	44	1610	4	Reference 5
							17520	44	Reference 14
ASH COLLECTION HOPPER	plugging	BN501	1.14E-04	8760	2	38	6757	24	Reference 3
							10989	4	Reference 5
							8760	38	Reference 13
ASH DEPRESSURIZATION HOPPER		BN502	9.12E-05	10970	7	43	6061	25	Reference 3
							4600	4	Reference 5
							10970	43	Reference 13
SULFATOR FEED HOPPER		BN508	1.07E-04	9320	8	44	5464	25	Reference 3
							7500	4	Reference 5
							9320	44	Reference 13
ROTARY VALVE		FD302	7.61E-05	13140	4	40	1610	4	Reference 5
							13140	40	Reference 13
FILTER		F502	7.61E-05	13140	20	56	13140	4	Reference 5
							13140	56	Reference 13
SOLIDS COOLER		E605	2.71E-05	36959	23	155	36959	23	Reference 5
							36959	155	Reference 13
PIPING/REFRACTORY			9.51E-06	105120	120	252	40000	252	Reference 5
							105120	252	Reference 13
VALVE, SOLIDS ISOLATION			2.28E-05	43800	4	136	43800	136	Reference 13
SOLIDS EDUCTOR	plugging		1.14E-04	8760	4	40	8760	40	Reference 13
FEEDLINE, ELBOWS	erosion		3.81E-05	26280	4	40	26280	40	Reference 13
I&C SYSTEM CONTROLS			6.60E-05	15150	4	40	15150	40	Reference 13
I&C CONTROL VALVES			6.60E-05	15150	4	40	15150	40	Reference 13



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960627-HB-F109

SUBSYSTEM DESCRIPTION DATA SHEET

1. Data Sheet Number: 9

2. Description:

Subsystem Name:	Fines Combustor
ABD I.D, Number:	10
Plant Capacity (%):	100
Plant Area:	Desulfurization (600)

3. Comments:

The function of the Fines Combustor subsystem is to represent the section of the plant that contains the combustion of the fines particles and all components associated with the Fines Combustor (H-602). This subsystem description encompasses part of Area 600, as it is described in section 3.2.4 of the Technical Baseline. A brief process description, as it applies to the UNIRAM model, is given below:

The Fines Combustor subsystem contains 10 components, and has a capacity state of 100%. This subsystem includes the ash feed components to the sulfator. The hoppers, (BN-503, 504, 507), have surge times of less than one hour. This subsystem contains no redundant components. The failure of any single component will cause a gasification shut down.

4. Availability:

Mean Time Between Failures (h): 713.0
Mean Downtime (h): 10.4
Availability (%): 98.6

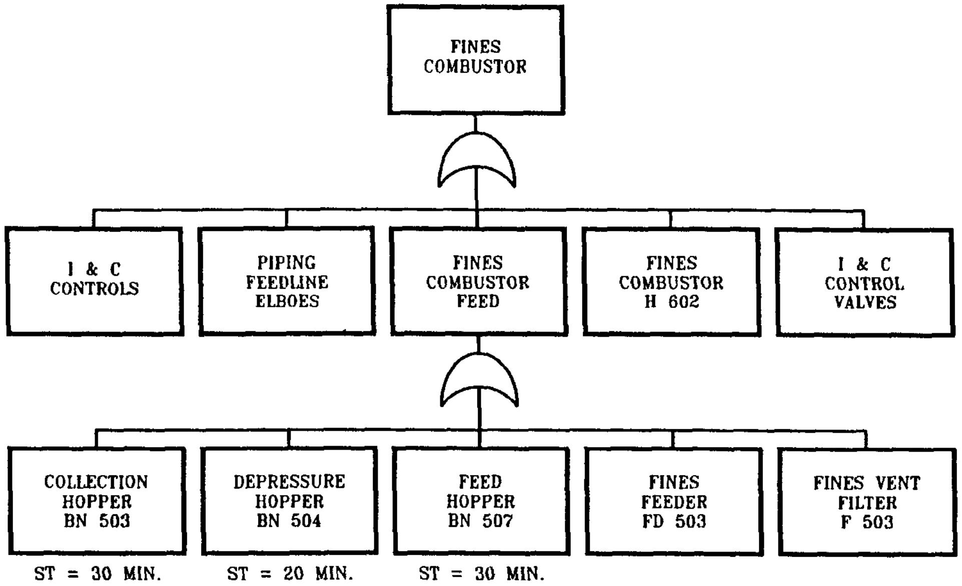
5. Critical Components:

Component	Equivalent Outage* Hours Downtime
Combuster, H-602, Cold Restart	41.8
Fines Feeder (FD-503), Hot Restart	8.3
Collection Hopper (BN-503), Inter. Restart	7.0
Feed Hopper (BN-507), Inter. Restart	6.6
Combustor, H-602	2.7
Fines Feeder, FD-503	0.8
Vent Filter, F-503	0.5

* Calendar hours lost at 97.8-MWe

SUBSYSTEM (10): FINES COMBUSTOR

COMPONENT	DESCRIPTION	ID #	FAILURE RATE	Pinon Pine Plant MTBF	Pinon Pine Plant MTTR	Pinon Pine Plant MDT	Industry Data MTBF	Industry Data MDT	SOURCE
AIR COMPRESSOR		C602	5.71E-05	17520	8	16	26280	42	Reference 1
							17520	16	Reference 13
COLLECTION HOPPER		BN503	1.14E-04	8760	2	38	6757	24	Reference 3
							10989	4	Reference 5
							8760	38	Reference 13
DEPRESSURIZATION HOPPER		BN504	9.12E-05	10970	7	43	6061	25	Reference 3
							4600	4	Reference 5
							10970	43	Reference 13
FEED HOPPER		BN507	1.07E-04	9320	8	44	5464	25	Reference 3
							7500	4	Reference 5
							9320	44	Reference 13
SCREW FEEDER		FD503	6.21E-04	1610	4	8	1610	4	Reference 5
							13140	8	Reference 13
FINES VENT FILTER		F503	7.61E-05	13140	20	56	13140	4	Reference 5
							13140	56	Reference 13
FINES COMBUSTOR		H602	1.92E-04	5205	41	173	22700	18	Reference 8
							5205	173	Reference 14
PIPING	feedline elbows		1.14E-05	87600	4	10	87600	10	Reference 13
I&C CONTROL VALVES			6.61E-05	15140	4	40	15140	40	Reference 13
I&C SYSTEM CONTROLS			6.60E-05	15150	3	6	15150	6	Reference 13



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960327-HB-F110

SUBSYSTEM DESCRIPTION DATA SHEET

1. Data Sheet Number: 10

2. Description:

Subsystem Name: Desulfurized Solids Removal
ABD I.D, Number: 11
Plant Capacity (%): 100
Plant Area: Desulfurization (600)

3. Comments:

The function of the Desulfurized Solids Removal subsystem is to represent the last part of the desulfurization process, which is the removal of the solids waste from the Sulfator (R-602) and the Fines Combustor (H-602). This subsystem description is mentioned in part at the end of section 3.2.4 of the Technical Baseline. A brief process description, as it applies to the UNIRAM model, is given below:

The Desulfurized Solids Removal subsystem contains 11 components, and has a capacity state of 100%. This subsystem models the bins, solids coolers and other related components utilized for transferring desulfurized solid wastes (ash and fines) to Solids Waste Removal, Area 1100 of the plant. This subsystem has no surge time. The failure of any single component will cause a gasification shut down, resulting in a hot, intermediate, or cold restart.

4. Availability:

Mean Time Between Failures (h): 1,400.3
Mean Downtime (h): 10.0
Availability (%): 99.3

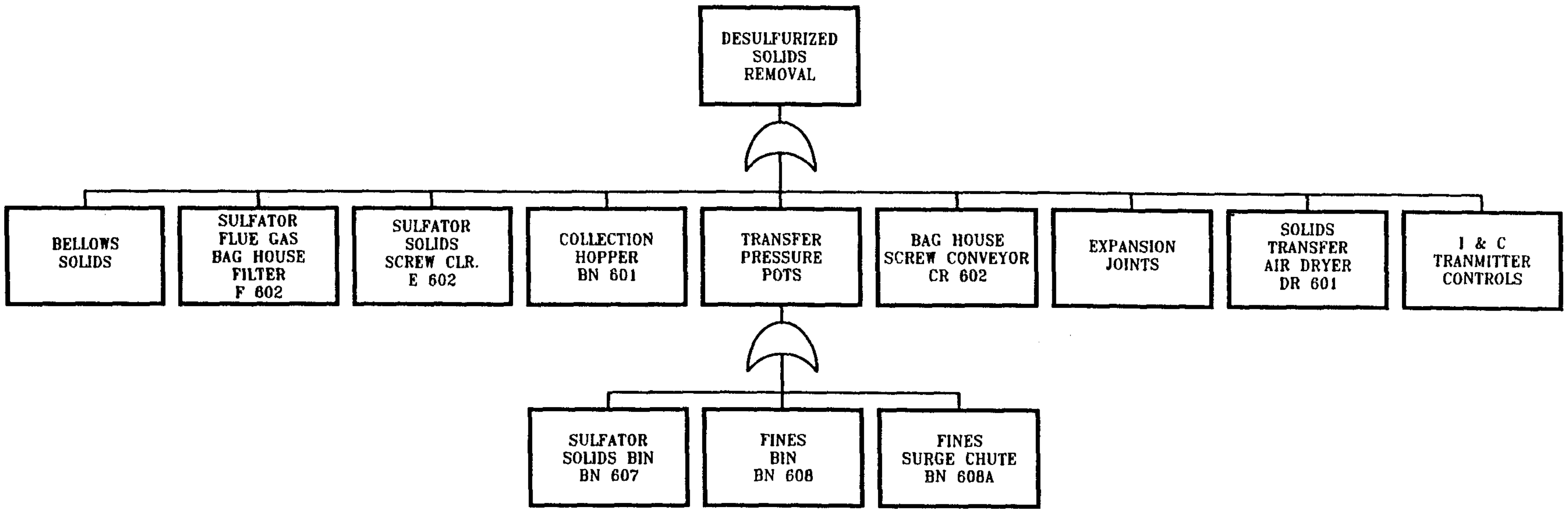
5. Critical Components:

Component	Equivalent Outage* Hours Downtime
Baghouse Filter (F-602), Cold Restart	24.8
Sulfator Solids Bin (BN-607), Inter. Restart	7.8
Fines Chute (BN-608A), Hot Restart	2.1

* Calendar hours lost at 97.8-MWe

SUBSYSTEM (11): DESULFURIZED SOLIDS REMOVAL

COMPONENT	DESCRIPTION	ID #	FAILURE RATE	Pinon Pine Plant MTBF	Pinon Pine Plant MTTR	Pinon Pine Plant MDT	Industry Data MTBF	Industry Data MDT	SOURCE
SCREW COOLER		E602	2.71E-05	36959	8	140	36959	23	Reference 5
							36959	140	Reference 13
COLLECTION HOPPER		BN601	4.57E-06	219000	60	192	6757	24	Reference 3
							10989	4	Reference 5
							219000	192	Reference 14
SULFATOR SOLIDS BIN		BN607	1.26E-04	7920	4	40	6061	25	Reference 3
							4600	4	Reference 5
							7920	40	Reference 13
FINES BIN		BN608	1.26E-04	7920	4	8	5464	25	Reference 3
							7500	4	Reference 5
							7920	8	Reference 13
FINES SURGE CHUTE		BN608A	1.54E-04	6482	8	16	5464	25	Reference 3
							7500	4	Reference 5
							6482	16	Reference 13
BAG HOUSE		CR602	3.81E-05	26280	16	32	26280	16	Reference 6
							26280	32	Reference 13
EXPANSION JOINTS			2.50E-05	40000	15	15	40000	15	Reference 1
SOLIDS TRANSFER AIR DRYER		DR601	7.50E-06	133333	13	26	9220	12	Reference 5
							133333	26	Reference 13
FLUE GAS BAG HOUSE FILTER		F602	1.14E-04	8760	24	156	109500	10	Reference 5
							8760	156	Reference 14
I&C TRANSMITTER CONT	for BN607		6.60E-05	15150	3	6	15150	6	Reference 13
BELLOWS	solids	EJ-19	2.50E-05	40000	15	30	40000	30	Reference 13



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960327-HB-F111

SUBSYSTEM DESCRIPTION DATA SHEET

1. Data Sheet Number: 11

2. Description:

Subsystem Name:	Particulate Removal
ABD I.D, Number:	12
Plant Capacity (%):	100
Plant Area:	Gas Stream Particulate Removal (500)

3. Comments:

The function of the Particulate Removal subsystem is to represent, the final removal of fines particles from the product fuel gas. This subsystem description is discussed in section 3.2.4 of the Technical Baseline. A brief description, as it applies to the UNIRAM model, is given below:

The Particulate Removal subsystem contains eight components, and has a capacity state of 100%. This subsystem is comprised of the Hot Gas Filter (F-501) and associated components of the Heat Transfer Fluid (HTF) package. This subsystem has no surge time, but the HTF package contains one set of redundant pumps. A failure of this subsystem, will cause a gasification island shut down.

4. Availability:

Mean Time Between Failures (h): 5,803.9
Mean Downtime (h): 46.7
Availability (%): 99.2

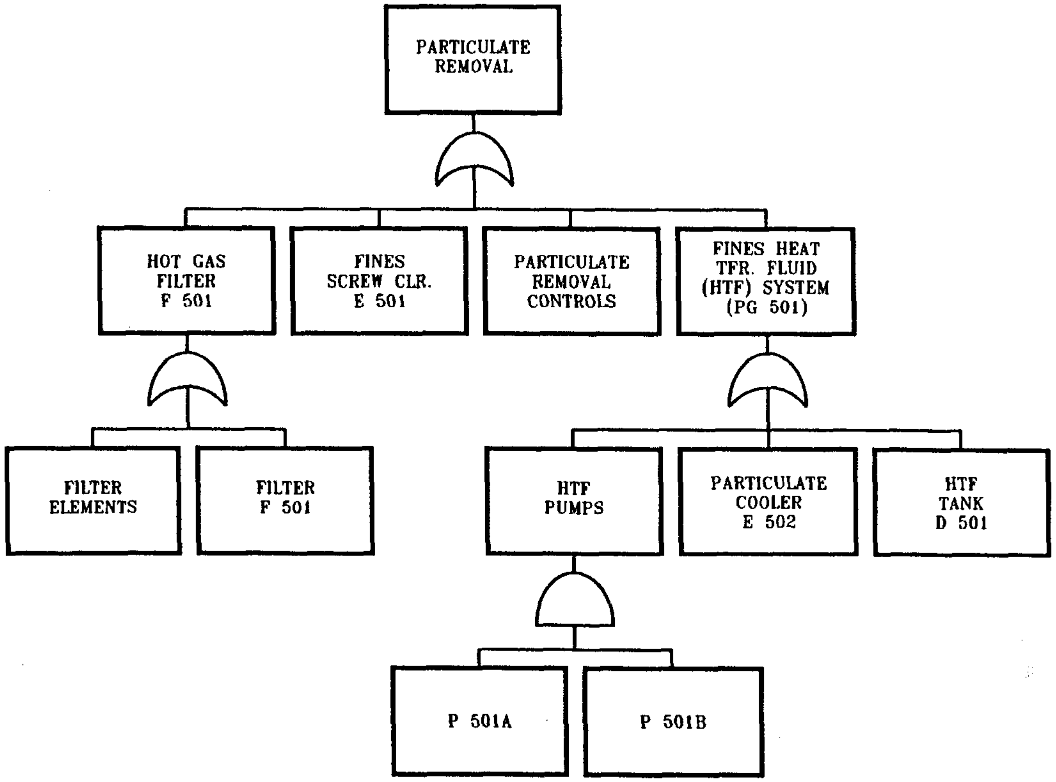
5. Critical Components:

Component	Equivalent Outage* Hours Downtime
Hot Gas Filter Elements	2.1

* Calendar hours lost at 97.8-MWe

SUBSYSTEM (12): PARTICULATE REMOVAL

COMPONENT	DESCRIPTION	ID #	FAILURE RATE	Pinon Pine Plant			Industry Data		SOURCE
				MTBF	MTTR	MDT	MTBF	MDT	
HOT GAS FILTER REFRAC	filters desulferized gas	F501	9.51E-06	105120	120	252	55439	20	Reference 5
							105120	252	Reference 13
SCREW COOLER	cools the fines from the hot gas filter F501	E501	2.71E-05	36959	8	44	36959	23	Reference 6
							36959	44	Reference 13
HTF PUMPS		P501 A/B (2)	5.41E-05	18479	8	16	18479	24	Reference 6
							18479	16	Reference 13
HTF PARTICULATE COOLE		E502	2.71E-05	36959	8	16	36959	23	Reference 6
							36959	16	Reference 13
PARTICULATE REMOVAL CONTROLS			6.60E-05	15150	3	6	15150	6	Reference 6
							15150	6	Reference 13
HOT GAS FILTER	elements	F501	3.81E-05	26280	160	292	26280	292	Reference 13
HTF TANK		D501	4.57E-06	219000	36	72	219000	72	Reference 13



FAULT TREE: [12]

ARINC

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960627-HB-F112

SUBSYSTEM DESCRIPTION DATA SHEET

1. Data Sheet Number: 12

2. Description:

Subsystem Name:	Solids Waste Removal
ABD I.D, Number:	13
Plant Capacity (%):	100
Plant Area:	Solid Waste Handling (1100)

3. Comments:

The function of the Solids Waste Removal subsystem is to represent the solid waste, consisting of ash, fines and sulfated limestone and its removal and storage. This subsystem description is represented in section 3.3.2 of the Technical Baseline. A brief process description, as it applies to the UNIRAM model, is given below:

The Solid Waste Removal subsystem contains eight components, and has a capacity state of 100%. This subsystem has a surge time of one day. The surge time, as it is represented in the model, accounts for the effects of solids waste removal by disposal trucks to an off site location.

4. Availability:

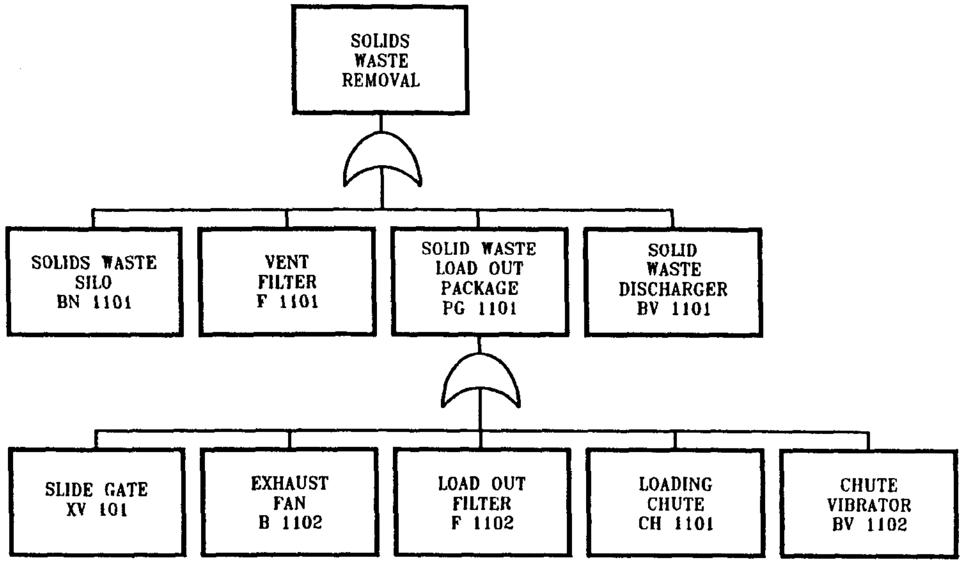
Mean Time Between Failures (h): greater than 25 years
Mean Downtime (h): 19.9
Availability (%): 99.9

5. Critical Components:

No critical components are identified that have a significant affect on EFOR.

SUBSYSTEM (13): SOLID WASTE REMOVAL

COMPONENT	DESCRIPTION	ID #	FAILURE RATE	Pinon Pine Plant MTBF	Pinon Pine Plant MTTR	Pinon Pine Plant MDT	Industry Data MTBF	Industry Data MDT	SOURCE
SOLID WASTE SILO		BN1101	1.05E-04	9495	4	4	8000	3	Reference 1
							10989	4	Reference 5
VENT FILTER		F1101	7.61E-05	13140	4	4	13140	4	Reference 5
SOLID WASTE DISCHARGER		BV1101	7.50E-06	133333	13	13	133333	13	Reference 13
SLIDE GATE		XV1101	7.50E-06	133333	13	13	133333	13	Reference 13
EXHAUST FAN		B1102	6.00E-06	166666	28	28	166666	28	Reference 1
LOADOUT FILTER		F1102	7.61E-05	13140	4	4	13140	4	Reference 5
LOADING CHUTE		CH1101	5.71E-05	17500	3	3	17500	3	Reference 5
CHUTE VIBRATOR		BV1102	5.71E-05	17500	3	3	17500	3	Reference 5



FAULT TREE: [13]

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960627-HB-F113

SUBSYSTEM DESCRIPTION DATA SHEET

1. Data Sheet Number: 13

2. Description:

Subsystem Name: Recycle Gas
ABD I.D, Number: 14
Plant Capacity (%): 100
Plant Area: Recycle Gas Compression (900)

3. Comments:

The function of the Recycle Gas subsystem is to represent the recompression and distribution of the recycled gas. This subsystem description encompasses Area 900, as described in section 3.2.6 of the Technical Baseline. A brief process description, as it pertains to the UNIRAM model is given below.

The Recycle Gas subsystem contains nine components, and has a capacity state of 100%. This subsystem has no derating and is not affected by a surge time. There are no redundant components. Failure of the subsystem will cause a gasification island shut down.

4. Availability:

Mean Time Between Failures (h): 2,398.5
Mean Downtime (h): 24.0
Availability (%): 99.0

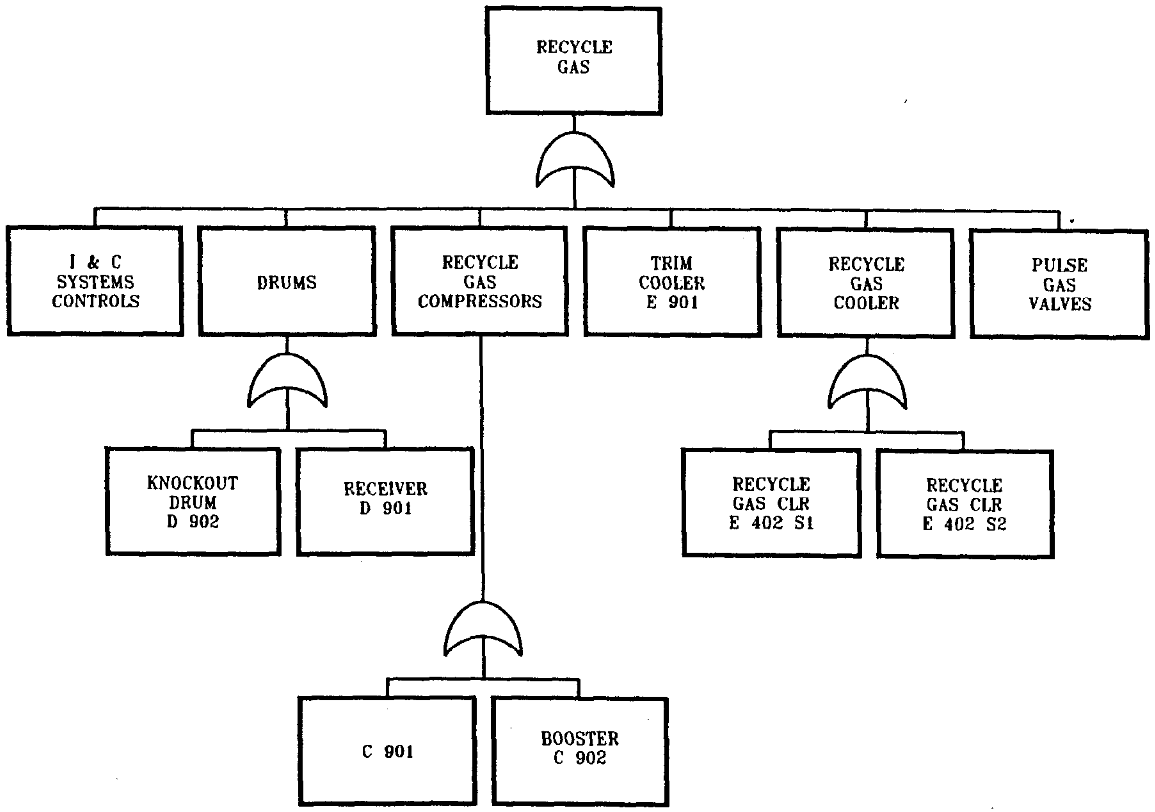
5. Critical Components:

Component	Equivalent Outage* Hours Downtime
Compressor (C-902), Hot Restart	2.2
Compressor, C-902	1.7
Compressor, C-901	0.8

* Calendar hours lost at 97.8-MWe

SUBSYSTEM (14): RECYCLED GAS

COMPONENT	DESCRIPTION	ID #	FAILURE RATE	Pinon Pine Plant MTBF	Pinon Pine Plant MTTR	Pinon Pine Plant MDT	Industry Data MTBF	Industry Data MDT	SOURCE
GAS COMPRESSOR	recycle gas	C901	6.61E-05	15140	34	166	15140	34	Reference 1
							15140	166	Reference 13
TRIM COOLERS	trim cooler for gas	E901	3.00E-05	33288	36	72	10000000	57	Reference 1
							33288	36	Reference 2
							422000	103	Reference 4
							33288	72	Reference 13
GAS RECEIVER	knockout and receiver drums for gas	D901	1.10E-05	91100	18	36	91100	18	Reference 1
							91104	15	Reference 2
							150800	80	Reference 5
							91100	36	Reference 13
GAS COOLERS	cools gas before it before it enters the C901	E402 S1/S2 (2)	4.57E-06	219000	103	235	422000	103	Reference 4
							219000	235	Reference 14
KNOCK-OUT DRUM		D902	1.10E-05	91110	18	36	91110	36	Reference 13
VALVES	pulse gas		5.71E-05	17520	2	4	17520	4	Reference 13
I&C SYS. CONTROLS			6.60E-05	15150	3	6	15150	6	Reference 13
COMPRESSOR	pulse gas	C902	1.67E-04	6000	30	60	6000	60	Reference 13



FAULT TREE: [14]

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960827-HB-F114

SUBSYSTEM DESCRIPTION DATA SHEET

1. Data Sheet Number: 14

2. Description:

Subsystem Name: Evaporative Cooler, (Evap. Cooler Derating)
ABD I.D, Number: 15, (16)
Plant Capacity (%): 100, (96)
Plant Area: Gas Turbine Generator (700)

3. Comments:

The function of the Evaporative Cooler and its associated derating subsystem is to account for times during the summer months when a loss of evaporative cooling would cause a derating of 4% to the entire plant

This subsystem description consists solely of the Evaporative Cooler and the Evap. Cooler Derating. A loss of the Evaporative Cooler during the worst case (Summer months) would not cause a total plant shut down. During other times of the year, when evaporative cooling is not utilized, the Evaporative Cooler has a negligible effect on plant operations.

4. Availability:

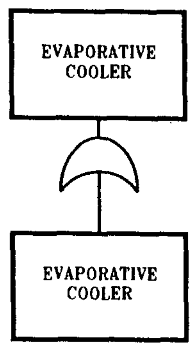
Mean Time Between Failures (h): 33,200.0
Mean Downtime (h): 35.0
Availability (%): 99.9

5. Critical Components:

No critical components are identified that have a significant affect on EFOR.

SUBSYSTEM (15): EVAPORATIVE COOLER

COMPONENT	DESCRIPTION	ID #	FAILURE RATE	Pinon Pine Plant MTBF	Pinon Pine Plant MTTR	Pinon Pine Plant MDT	Industry Data MTBF	Industry Data MDT	SOURCE
EVAPORATIVE COOLER			3.01E-05	33200	35	35	33200	35	Reference 1



FAULT TREE: [15]

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960627-HB-Ft15

SUBSYSTEM DESCRIPTION DATA SHEET

1. Data Sheet Number: 15

2. Description:

Subsystem Name: Gas Turbine and Generator
ABD I.D, Number: 17
Plant Capacity (%): 100
Plant Area: Gas Turbine Generator (700)

3. Comments:

The function of the Gas Turbine and Generator subsystem is to represent the Gas Turbine (GT-701) and its associated equipment. This subsystem description encompasses Area 700, as described in section 3.1.1 of the Technical Baseline. A brief process description, as it pertains to the UNIRAM model is given below:

The Gas Turbine and Generator subsystem contains 10 components, and has a capacity state of 100%. This subsystem has no surge time, and no redundant components. A failure of any single component will cause a total plant shut down.

4. Availability:

Mean Time Between Failures (h): 2,006,7
Mean Downtime (h): 40.0
Availability (%): 98.1

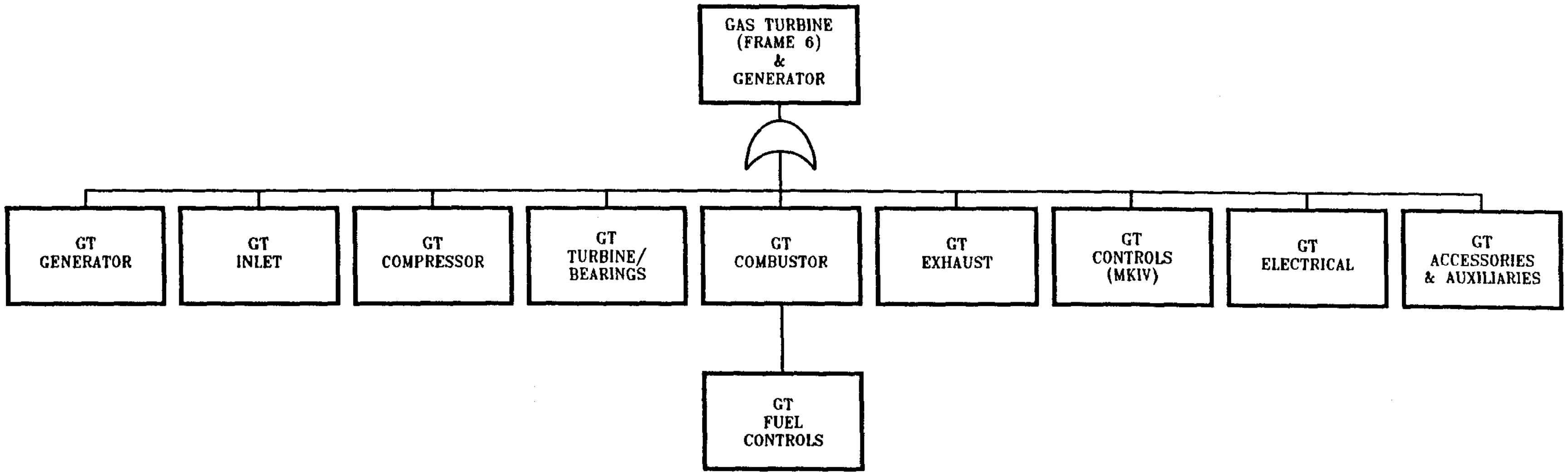
5. Critical Components:

Component	Equivalent Outage* Hours Downtime
GT Compressor	56.6
Turbine Bearings	34.3
GT Generator	19.2
GT Electrical	13.0
GT Access/Aux.	10.6
GT Combustor	5.9
GT Exhaust	4.3
GT Access/Aux, Hot Restart	2.1
GT Inlet	1.9

* Calendar hours lost at 97.8-MWe

SUBSYSTEM (17): GAS TURBINE & GENERATOR

COMPONENT	DESCRIPTION	ID #	FAILURE RATE	Pinon Pine Plant			Industry Data		SOURCE
				MTBF	MTTR	MDT	MTBF	MDT	
GT GENERATOR			8.37E-05	11948	31	31	947	40	Reference 1
							9609	22	Reference 6
GT INLET			2.31E-05	43312	11	11	46000	8	Reference 1
							40623	14	Reference 8
GT COMPRESSORS			3.31E-05	30194	230	362	30194	230	Reference 8
GT TURBINE/BEARINGS			1.96E-05	51108	237	369	51108	237	Reference 8
GT COMBUSTOR			4.41E-05	22700	18	18	22700	18	Reference 8
GT EXHAUST			1.64E-05	60933	35	35	60933	35	Reference 8
GT CONTROLS (MKIV)			3.27E-05	30607	2	2	30607	2	Reference 8
GT ELECTRICAL			7.02E-05	14250	25	25	13500	30	Reference 1
GT ACCESSORIES & AUXILIARIES			1.59E-04	6296	9	9	94700	10	Reference 1
							6296	9	Reference 8
GT FUEL CONTROLS			1.67E-05	59772	3	3	59772	3	Reference 7



FAULT TREE: [17]

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960527-HB-F117

SUBSYSTEM DESCRIPTION DATA SHEET

1. Data Sheet Number: 16

2. Description:

Subsystem Name:	HRSG Power Island
ABD I.D, Number:	18
Plant Capacity (%):	100
Plant Area:	Steam Turbine Generator and Heat Recovery Steam Generator (Area 800)

3. Comments:

The function of the HRSG Power Island subsystem is to represent the heat Recovery Steam Generator (SG-801) and its associated equipment (i.e. boiler feed water pumps, deaerators, steam drums). The HRSG is described in section 3.1.2.1 of the Technical Baseline. A brief process description, as it pertains to the UNIRAM model is given below:

The HRSG Power Island subsystem contains 14 components, and has a capacity state of 100%. This subsystem has no derating and is not affected by a surge time. This subsystem contains various redundant pumps. A failure of this subsystem will cause a total plant shut down.

4. Availability:

Mean Time Between Failures (h): 6,236.7
Mean Downtime (h): 57.5
Availability (%): 99.1

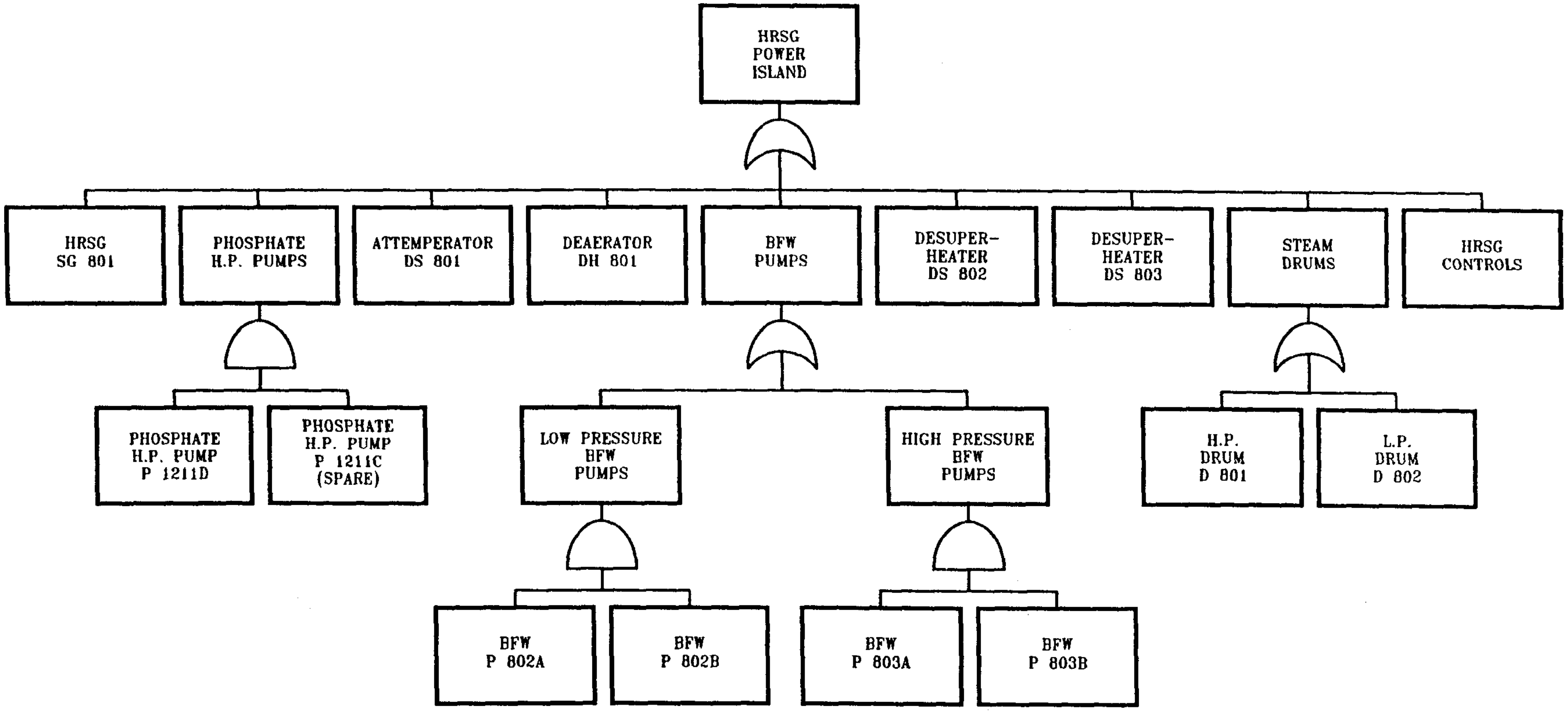
5. Critical Components:

Component	Equivalent Outage* Hours Downtime
HRSG, SG801	51.4
L.P. Drum, D802	4.3
H.P. Drum, D801	4.3
Deaerator, DH801	3.1
HRSG Controls	2.6
Attemperator, DS801	0.8
M.P. Desuperheater, DS802	0.8
PEG Desuperheater, DS803	0.8

* Calendar hours lost at 97.8-MWe

SUBSYSTEM (18): HRSG POWER ISLAND

COMPONENT	DESCRIPTION	ID #	FAILURE RATE	Pinon Pine Plant MTBF	MTTR	MDT	Industry Data MTBF	MDT	SOURCE
STEAM DRUMS		D801/2 (2)	1.50E-05	66667	39	75	66667	39	Reference 2
							438000	49	Reference 9
ATTEMPERATOR		DS801	2.28E-06	438000	49	85	438000	49	Reference 9
DEAERATOR		DH801	1.39E-05	71800	30	30	71800	38	Reference 1
							71429	21	Reference 10
HRSG CONTROLS			4.34E-05	23052	8	8	23052	8	Reference 9
DESUPERHEATER		DS803	2.28E-06	438000	49	85	438000	49	Reference 9
DESUPERHEATER		DS802	2.28E-06	438000	49	85	438000	49	Reference 9
H.P. PHOSPHATE PUMS		P1211 D/C (2)	1.16E-04	8652	4.8	4.8	8652	4.8	Reference 6
L.P. BFW PUMPS		P802 A/B (2)	3.14E-05	31882	26	26	10000	49	Reference 1
							53763	3	Reference 6
H.P. BFW PUMPS		P803 A/B (2)	3.14E-05	31882	26	26	10000	49	Reference 1
							53763	3	Reference 6
HRSG		SG801	6.61E-05	15140	105	237	15140	105	Reference 1



FAULT TREE: [18]

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960627-HB-F118

SUBSYSTEM DESCRIPTION DATA SHEET

1. Data Sheet Number: 17

2. Description:

Subsystem Name:	BFW Makeup and Treatment
ABD I.D, Number:	19
Plant Capacity (%):	100
Plant Area:	Balance of Plant (1200)

3. Comments:

The function of the BFW Makeup and Treatment subsystem is to represent boiler feedwater supply and storage, and the boiler water treatment. This subsystem description encompasses Area 1200, as described in section 3.3.3 of the Technical Baseline. A brief process description, as it pertains to the UNIRAM model is given below:

The BFW Makeup and Treatment subsystem contains 14 components, and has a capacity state of 100%. This subsystem has no derating and is not affected by a surge time. The subsystem includes redundancy for all pumps and redundant Cation/Anion units.

4. Availability:

Mean Time Between Failures (h): 10,096.1
Mean Downtime (h): 7.0
Availability (%): 99.9

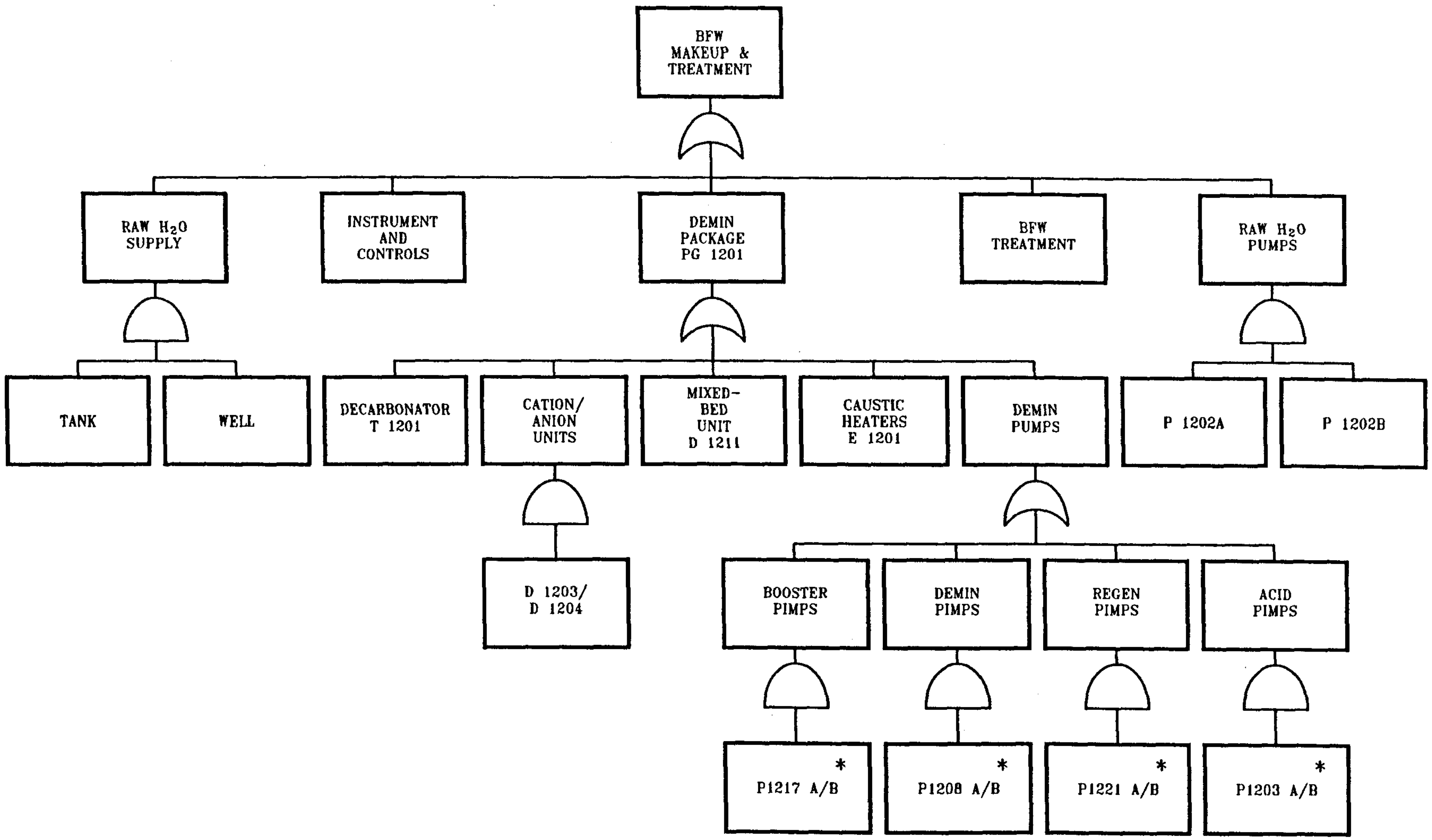
5. Critical Components:

Component	Equivalent Outage* Hours Downtime
Instrument/Controls	2.9

* Calendar hours lost at 97.8-MWe

SUBSYSTEM (19): BFW MAKE-UP AND TREATMENT

COMPONENT	DESCRIPTION	ID #	FAILURE RATE	Pinon Pine Plant MTBF	Pinon Pine Plant MTTR	Pinon Pine Plant MDT	Industry Data MTBF	Industry Data MDT	SOURCE
INSTRUMENTATION AND CONTROLS			6.60E-05	15150	6	6	15150	6	Reference 6
BFW TREATMENT			1.00E-05	100000	16	16	100000	16	Reference 5
RAW H2O SUPPLY		TANK/WELL (2)	3.03E-05	33000	13	13	33000	13	Reference 1
RAW H2O PUMPS		P1202 A/B (2)	3.03E-05	33000	13	13	33000	13	Reference 1
ANION/CATION UNITS		D1204/D1203 (1)	7.91E-05	12640	70	202	25280	70	Reference 1
MIXED BED UNIT		D1211	1.14E-05	87600	6	6	87600	6	Reference 9
CAUSTIC HEATERS		E1201	1.00E-05	100000	3	3	100000	3	Reference 10
DEMIN. PUMPS		P1208 A/B (1)	6.01E-05	16650	13	13	33300	13	Reference 1
DEMIN. BOOSTER PUMPS		P1217 A/B (1)	6.01E-05	16650	13	13	33300	13	Reference 1
DEMIN. REGEN. PUMPS		P1221 A/B (1)	6.01E-05	16650	13	13	33300	13	Reference 1
DEMIN. ACID PUMPS		P1203 A/B (1)	6.01E-05	16650	13	13	33300	13	Reference 1
DECARBONATOR		T1201	3.00E-05	33300	13	13	33300	13	Reference 1



* A/B INDICATES TWO IDENTICAL REDUNDANT COMPONENTS.

FAULT TREE: [19]

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960627-HB-F119

SUBSYSTEM DESCRIPTION DATA SHEET

1. Data Sheet Number: 18

2. Description:

Subsystem Name:	Steam Turbine and Generator, (Steam Turbine Bypass)
ABD I.D, Number:	20, (21)
Plant Capacity (%):	100, (53)
Plant Area:	Steam Turbine Generator and Heat Recovery Steam Generator (Area 800)

3. Comments:

The function of the Steam Turbine and Generator and its associated bypass subsystems is to represent the Steam Turbine Generator (TG-801), its associated equipment, and the bypass derating: in case of failure. This subsystem description encompasses Area 800, as described in section 3.1.2.3 of the Technical Baseline. A brief process description, as it pertains to the UNIRAM model is given below:

The Steam Turbine and Generator and Steam Turbine Bypass subsystem contains eight components, and has a capacity state of 100%. If the TG-801 fails it will derate the plant 47%. This subsystem contains redundant condensate pumps. The plant is designed to operate indefinitely in the steam turbine bypass mode if need be. A failure of this subsystem will not cause a total plant shut down.

4. Availability:

Mean Time Between Failures (h): 4,242.7
Mean Downtime (h): 29.7
Availability (%): 99.3

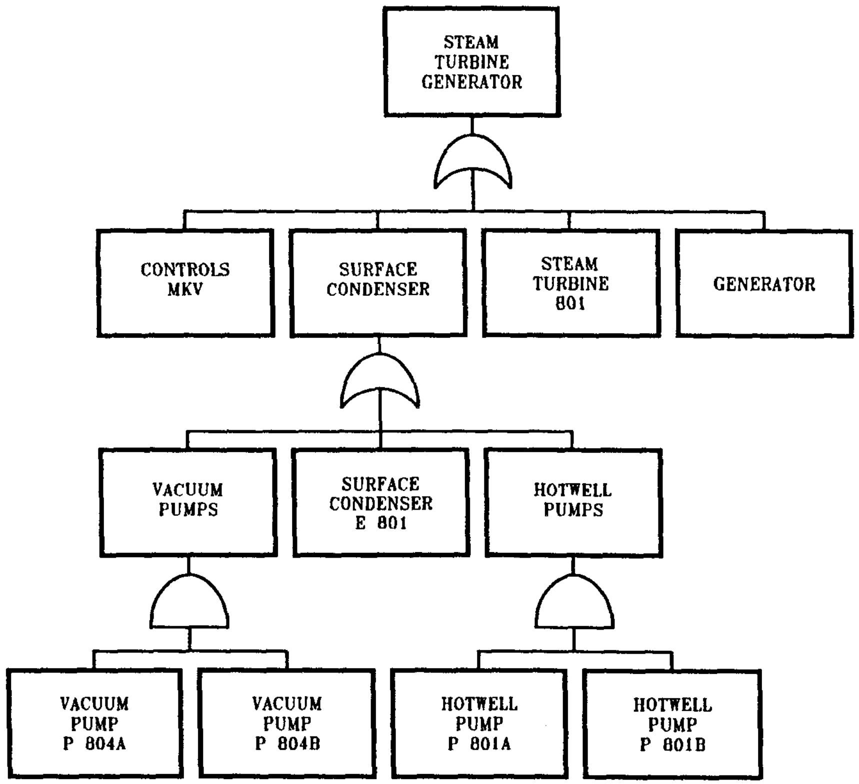
5. Critical Components:

Component	Equivalent Outage* Hours Downtime
Generator	8.7
Turbine, TG801	7.7
Surface Condenser, E801	3.9
Controls MKV	0.8

* Calendar hours lost at 97.8-MWe

SUBSYSTEM (20): STEAM TURBINE GENERATOR

COMPONENT	DESCRIPTION	ID #	FAILURE RATE	Pinon Pine Plant			Industry Data		SOURCE
				MTBF	MTTR	MDT	MTBF	MDT	
STEAM TURBINE		TG801	8.47E-05	11800	30	30	8600	24	Reference 1
							8621	64	Reference 2
							18180	3	Reference 6
GENERATOR			6.55E-05	15263	44	80	12346	80	Reference 2
							18180	7	Reference 6
SURFACE CONDENSER		E801	5.70E-05	17550	23	23	25000	36	Reference 1
							10100	9	Reference 6
CONDENSATE PUMPS	hotwell and vacuum	P801 A/B (2)	3.80E-05	26282	29	29	33300	32	Reference 1
							33288	31	Reference 2
							12258	24	Reference 6
CONTROLS MKV			2.83E-05	35300	9	9	26800	13	Reference 1
							43800	5	Reference 9
VACUUM PUMP		P804 A/B (2)	6.74E-05	14847	5	5	14847	5	Reference 9



FAULT TREE: [20]

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960627-HB-F120

SUBSYSTEM DESCRIPTION DATA SHEET

1. Data Sheet Number: 19

2. Description:

Subsystem Name:	Cooling Tower, (C.T. Derating)
ABD I.D, Number:	22, (23)
Plant Capacity (%):	100, (90)
Plant Area:	Balance of Plant (1200)

3. Comments:

The function of the Cooling Tower and C.T. Derating subsystems is to represent the effect of the Cooling Tower (CT-1201) on plant operations. This subsystem is described in section 3.3.3.4 of the Technical Baseline. A brief description, as it applies to the UNIRAM model is given below:

The Cooling Tower subsystem contains eight components, and has a capacity state of 100%. There is an associated derating of 10% (due to failure of C.T. cells), which accounts for times during the summer months when a partial loss of CT-1201 could bring about a 90% capacity state for the entire plant. This subsystem contains two cooling water supply pumps, which share a common spare. A failure of two of the three pumps would cause a total loss of this subsystem. A total loss of the Cooling Tower would cause a complete plant shut down.

4. Availability:

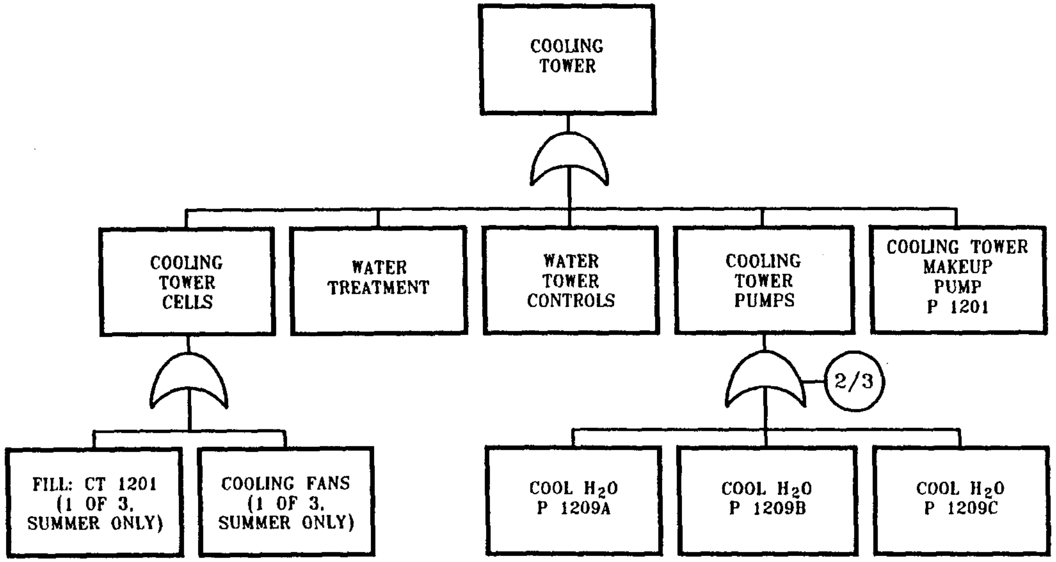
Mean Time Between Failures (h): 3,310.6
Mean Downtime (h): 11.3
Availability (%): 99.7

5. Critical Components:

No critical components are identified that have a significant affect on EFOR.

SUBSYSTEM (22): COOLING TOWER

COMPONENT	DESCRIPTION	ID #	FAILURE RATE	Pinon Pine Plant			Industry Data		SOURCE
				MTBF	MTTR	MDT	MTBF	MDT	
THREE CELL COOLING TOWER		CT1201	5.71E-06	175200	192	224	175200	2	Reference 9
COOLING POND PUMP		P1201	5.41E-05	18479	24	24	18479	24	Reference 6
CIRC. H2O TREATMENT			1.72E-04	5801	3	3	5801	3	Reference 9
COOLING TOWER FANS			3.69E-06	271182	30	30	271182	30	Reference 9
COOLING H2O PUMPS		P1209 A/B/C (3)	3.54E-05	28283	21	21	18479	24	Reference 6
							38087	18	Reference 9
COOLING TOWER CONTROLS			6.60E-05	15150	6	6	15150	6	Reference 6



FAULT TREE: [22]

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960627-HB-F122

SUBSYSTEM DESCRIPTION DATA SHEET

1. Data Sheet Number: 20

2. Description:

Subsystem Name: Instrument and Plant Air
ABD I.D, Number: 24
Plant Capacity (%): 100
Plant Area: Balance of Plant (1200)

3. Comments:

The function of the Instrument and Plant Air subsystem is to represent that part of the plant which produces necessary instrument and service air by means of an air compressor system. This subsystem description is part of Area 12000, as described in section 3.3.3.5 of the Technical Baseline. A brief process description, as it pertains to the UNIRAM model is given below:

The Instrument and Plant Air subsystem contains six components, and has a capacity state of 100%. This subsystem has no derating and is not affected by a surge time. This subsystem contains redundant compressors and air dryers. A failure of this subsystem will cause a total plant shut down.

4. Availability:

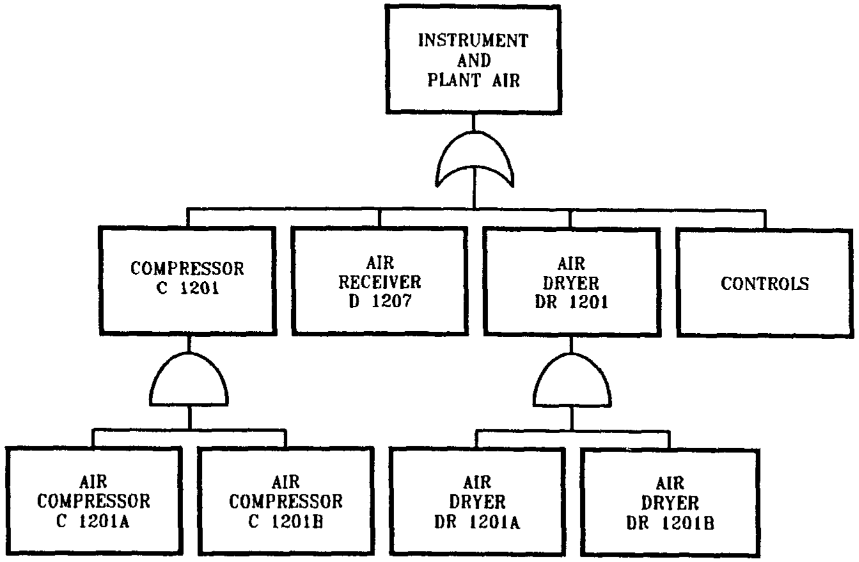
Mean Time Between Failures (h): 15,031.6
Mean Downtime (h): 6.0
Availability (%): 99.9

5. Critical Components:

No critical components are identified that have a significant affect on EFOR.

SUBSYSTEM (24): INSTRUMENT AND PLANT AIR

COMPONENT	DESCRIPTION	ID #	FAILURE RATE	Pinon Pine Plant MTBF	MTTR	MDT	Industry Data MTBF	MDT	SOURCE
AIR COMPRESSIOR		C1201 A/B (2)	3.52E-06	284091	6	6	59880	120	Reference 5
							284091	6	Reference 10
AIR RECEIVER		D1207	5.20E-07	1923077	3	3	1923077	3	Reference 10
AIR DRYER		DR1201 A/B (2)	5.20E-07	1923077	3	3	1923077	3	Reference 10
CONTROLS			6.60E-05	15150	6	6	15150	6	Reference 6



FAULT TREE: [24]

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960627-HB-F124

SUBSYSTEM DESCRIPTION DATA SHEET

1. Data Sheet Number: 21

2. Description:

Subsystem Name:	Electrical Distribution System
ABD I.D, Number:	25
Plant Capacity (%):	100
Plant Area:	Balance of Plant (1200)

3. Comments:

The function of the Electrical Distribution System subsystem is to represent the affects of the electrical distribution system on plant operation. This subsystem is described in section 3.4 of the Technical Baseline. A brief process description, as it pertains to the UNIRAM model is given below:

The Electrical Distribution System subsystem contains 15 components, and has a capacity state of 100%. This subsystem has no derating and is not affected by a surge time. The subsystem features extensive redundancy at the 4.16kV and 13.2kV service entrances. A failure of this subsystem will cause a total plant shut down.

4. Availability:

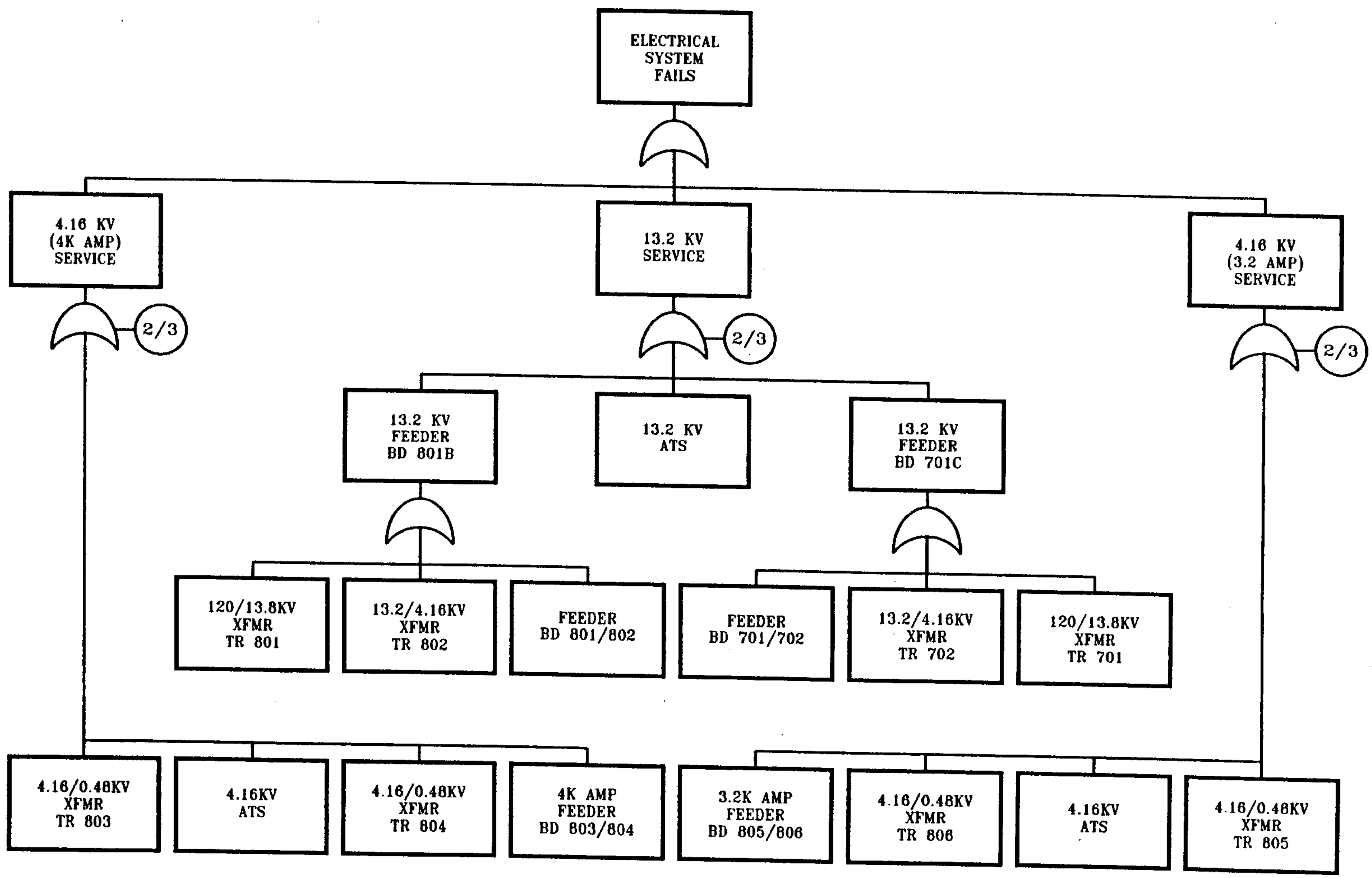
Mean Time Between Failures (h): greater than 25 years
Mean Downtime (h): less than one hour
Availability (%): 99.9

5. Critical Components:

No critical components are identified that have a significant affect on EFOR.

SUBSYSTEM (25): ELECTRICAL DISTRIBUTION SYSTEM

COMPONENT	DESCRIPTION	ID #	FAILURE RATE	Pinon Pine Plant MTBF	Pinon Pine Plant MTTR	Pinon Pine Plant MDT	Industry Data MTBF	Industry Data MDT	SOURCE
4.16/0.48 KV X FMR (TR803)			3.42E-07	2920000	174	306	2920000	306	Reference 12
4.16 KV ATS			6.96E-07	1436066	4	4	1436066	4	Reference 12
4.16/0.48 KV X FMR (TR804)			3.42E-07	2920000	174	306	2920000	306	Reference 12
120/13.8 KV X FMR (TR801)			1.48E-06	673846	174	306	673846	306	Reference 12
13.2/4.16 KV X FMR (TR802)			3.42E-07	2920000	174	306	2920000	306	Reference 12
FEEDER (BD801/802)			7.00E-07	1429038	53	89	1429038	89	Reference 12
13.2 KV ATS			6.96E-07	1436066	4	4	1436066	4	Reference 12
FEEDER (BD701/702)			7.00E-07	1429038	53	89	1429038	89	Reference 12
13.2/4.16 X FMR (TR702)			3.42E-07	2920000	174	306	2920000	306	Reference 12
120/13.8 KV X FMR (TR701)			1.48E-06	673846	174	306	673846	306	Reference 12
3.2 K AMP FEEDER (BD805/806)			7.00E-07	1429038	53	89	1429038	53	Reference 12
4.16/0.48 KV X FMR (TR806)			3.42E-07	2920000	174	306	2920000	306	Reference 12
4.16 KV ATS			6.96E-07	1436066	4	4	1436066	4	Reference 12
4.16/0.48 KV X FMR (TR805)			3.42E-07	2920000	174	306	2920000	306	Reference 12
4K AMP FEEDER (BD 803/804)			7.00E-07	1429038	53	89	1429038	89	Reference 12



FAULT TREE: [25]

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960627-HB-F125

SUBSYSTEM DESCRIPTION DATA SHEET

1. Data Sheet Number: 22

2. Description:

Subsystem Name: Plant Controls
ABD I.D, Number: 26
Plant Capacity (%): 100
Plant Area: Digital Control System (DCS)

3. Comments:

The function of the Plant Controls subsystem is to represent the effect of plant process and supervisory controls on plant availability. This subsystem description is presented in section 3.5 of the Technical Baseline. A brief process description, as it pertains to the UNIRAM model is given below:

The Plant Controls subsystem contains one component, and has a capacity state of 100%. This subsystem has no derating and is not affected by a surge time. A failure of this subsystem will cause a total plant shut down.

4. Availability:

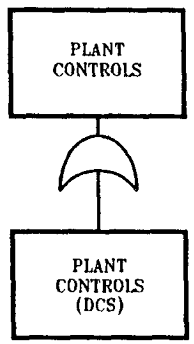
Mean Time Between Failures (h): 4,431.0
Mean Downtime (h): 3.0
Availability (%): 99.9

5. Critical Components:

No critical components are identified that have a significant affect on EFOR.

SUBSYSTEM (26): PLANT CONTROLS

COMPONENT	DESCRIPTION	ID #	FAILURE RATE	Pinon Pine Plant			Industry Data		SOURCE
				MTBF	MTTR	MDT	MTBF	MDT	
PLANT CONTROLS (DCS)			2.26E-04	4431	3	3	4431	3	Reference 9



FAULT TREE: [26]

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960627-HB-F126

SUBSYSTEM DESCRIPTION DATA SHEET

1. Data Sheet Number: 23

2. Description:

Subsystem Name: Waste Water Treatment
ABD I.D, Number: 27
Plant Capacity (%): 100
Plant Area: Waste Water Treatment (1000)

3. Comments:

The function of the Waste Water Treatment subsystem is to represent the treatment of water from the demineralization system and the cooling tower. This subsystem description is presented in section 3.3.4 of the Technical Baseline. A brief process description, as it pertains to the UNIRAM model is given below:

In the event of a failure of this subsystem, the treatment of water can be bypassed directly to a six acre evaporation pond. A failure of this subsystem is highly unlikely to cause a total plant shut down. A surge time of 48 hours is applied to this subsystem that limits the time that the Waste Water Treatment System can operate in the evaporation pond bypass mode. Failure is highly improbable, but is estimated to occur about every 100 years, due to catastrophic environmental events.

4. Availability:

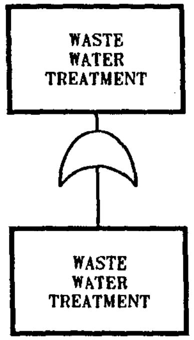
Mean Time Between Failures (h): greater than 25 years
Mean Downtime (h): 48
Availability (%): 99.9

5. Critical Components:

No critical components are identified that have a significant affect on EFOR.

SUBSYSTEM (27): WASTE WATER TREATMENT

COMPONENT	DESCRIPTION	ID #	FAILURE RATE	Pinon Pine Plant MTBF	Pinon Pine Plant MTTR	Pinon Pine Plant MDT	Industry Data MTBF	Industry Data MDT	SOURCE
WASTE WATER TREATMENT			1.14E-06	876000	48	84	876000	84	Reference 15



FAULT TREE: [27]

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960827-HB-F127

SUBSYSTEM DESCRIPTION DATA SHEET

1. Data Sheet Number: 24

2. Description:

Subsystem Name:	Catastrophic Events
ABD I.D, Number:	28
Plant Capacity (%):	100
Plant Area:	Entire Plant

3. Comments:

The function of the Catastrophic Events subsystem is to represent the uncommon or unexpected failures or complications that could result in a total plant failure. A brief process description, as it pertains to the UNIRAM model is given below:

The Catastrophic Events subsystem contains one component that relates to the occurrence of fires and explosions estimated to occur at a 100-year frequency.

4. Availability:

Mean Time Between Failures (h): greater than 25 years
Mean Downtime (h): 336.0
Availability (%): 99.9

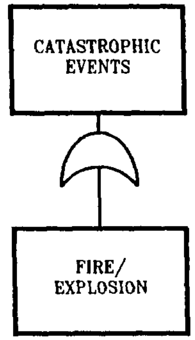
5. Critical Components:

Component	Equivalent Outage* Hours Downtime
Fire/Explosion	2.8

* Calendar hours lost at 97.8-MWe

SUBSYSTEM (28): CATASTROPHIC EVENTS

COMPONENT	DESCRIPTION	ID #	FAILURE RATE	Pinon Pine Plant MTBF	Pinon Pine Plant MTTR	Pinon Pine Plant MDT	Industry Data MTBF	Industry Data MDT	SOURCE
HUMAN ERROR			2.20E-05	45450	2	2	4431	2	Reference 9
FIRE/EXPLOSION			1.14E-06	876000	336	468	876000	468	Reference 9



FAULT TREE: [28]

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960827-HB-F128

SUBSYSTEM DESCRIPTION DATA SHEET

1. Data Sheet Number: 25

2. Description:

Subsystem Name: Natgas/CC Derating
ABD I.D, Number: 29
Plant Capacity (%): 90
Plant Area: Entire Gasification Island

3. Comments:

The function of the Natgas/CC Derating subsystem is to model the bypass of the plant's normal syngas operation to the crossover to Natgas operation. Whenever there is a failure bypass resulting in a gasification island shutdown, this fuel transfer is accounted for by the Natgas/CC Derating.

This Natgas/CC Derating bypass results in a reduced capacity of 90.4-MWe or 92.5% of full capacity. This derating of 7.5% will continue as long as the plant is operated in the natgas mode. This 7.5% derating is associated with the loss of steam of the gasification island HRSGs, which feed into the power island HRSG. This steam loss results in a power loss by the steam turbine and thus an overall reduced plant capacity.

4. Availability:

Mean Time Between Failures (h): na
Mean Downtime (h): na
Availability (%): na

5. Critical Components:

There are no critical components in this subsystem.

SUBSYSTEM DESCRIPTION DATA SHEET

1. Data Sheet Number: 26

2. Description:

Subsystem Name:	Hot Restart Mode, (Hot Restart Derating)
ABD I.D, Number:	30, (31)
Plant Capacity (%):	100, (77)
Plant Area:	Entire Plant

3. Comments:

The function of the Hot Restart Mode and its associated Hot Restart Derating subsystem is to represent the derating associated with equipment repairs that have MTTRs less than 36 hours. The subsystem represents 144 components. A total of 120 components have failure rates < 10^{-4} failures per year and are included in the "Balance of Components". The 23 percentage point derating for a hot restart is described in Section B.1.

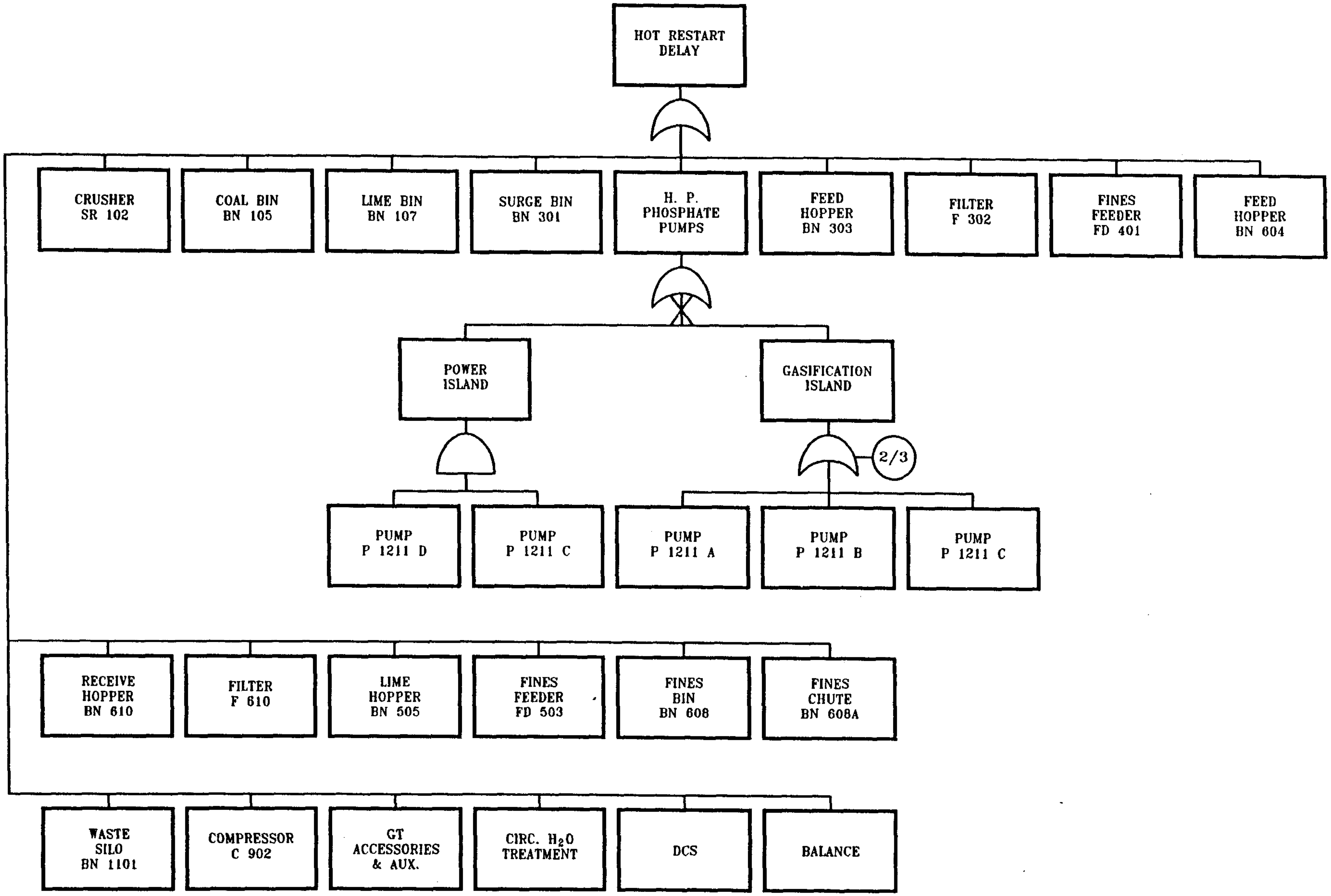
4. Availability:

Mean Time Between Failures (h): 113.7
Mean Downtime (h): 11.8
Availability (%): 90.6

5. Critical Components:

Component	Equivalent Outage* Hours Downtime
Hot Restart (Balance of Components)	64.4

* Calendar hours lost at 97.8-MWe



FAULT TREE: [30]

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SUBSYSTEM DESCRIPTION DATA SHEET

1. Data Sheet Number: 27

2. Description:

Subsystem Name:	Intermediate Restart Mode, (Intermediate Restart Derating)
ABD I.D, Number:	32, (33)
Plant Capacity (%):	100, (72)
Plant Area:	Entire Plant

3. Comments:

The function of the Intermediate Restart Mode and its associated derating subsystem is to represent the derating associated with equipment repairs that have MTTRs between 36 and 68 hours. The subsystem represents 41 components. A total of 32 components have failure rates < 10^{-4} failures per year and are included in "Balance of Components". The 28 percentage point derating for an intermediate restart is described in Section B.2.

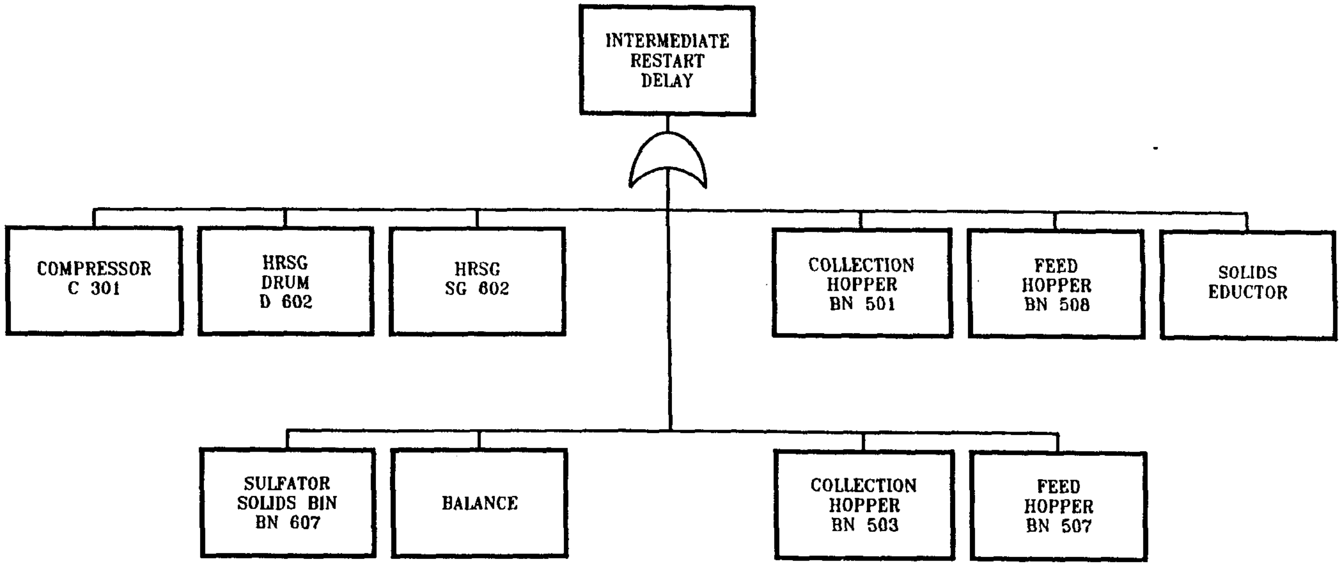
4. Availability:

Mean Time Between Failures (h): 485.1
Mean Downtime (h): 43.4
Availability (%): 91.8

5. Critical Components:

Component	Equivalent Outage* Hours Downtime
Intermediate Restart (Balance of Components)	60.5

* Calendar hours lost at 97.8-MWe



FAULT TREE: [32]

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SUBSYSTEM DESCRIPTION DATA SHEET

1. Data Sheet Number: 28

2. Description:

Subsystem Name:	Cold Restart Mode, (Cold Restart Derating)
ABD I.D, Number:	34, (35)
Plant Capacity (%):	100, (71)
Plant Area:	Entire Plant

3. Comments:

The function of the Cold Restart Mode and its associated derating subsystem is to represent the derating associated with equipment repairs that have MTTRs greater than 68 hours. The subsystem, represents 47 components. A total of 44 components have failure rates < 10^{-4} failures per year and are included in the "Balance of Components". The 29 percentage point derating for a cold restart is described in Section B.3.

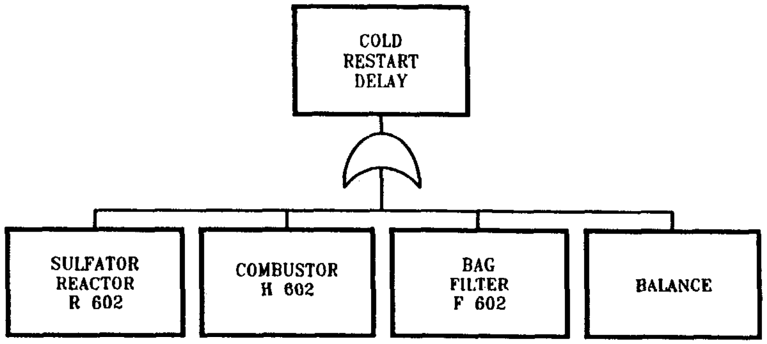
4. Availability:

Mean Time Between Failures (h): 555.7
Mean Downtime (h): 153.7
Availability (%): 78.3

5. Critical Components:

Component	Equivalent Outage* Hours Downtime
Cold Restart (Balance of Components)	196.7

* Calendar hours lost at 97.8-MWe



FAULT TREE: [34]

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APPENDIX B

RESTART SUBSYSTEM DESCRIPTIONS AND SUPPORTING CALCULATIONS

This Appendix contains the calculations for the three start-up cases and the preventive maintenance plan addressed in section 2. Components represented in the various restart cases are also listed.

B.1 CALCULATION OF AVERAGE PLANT DERATING DUE TO A HOT RESTART (HR)

The HR derating considers the ability of the plant to rapidly return to syngas operation after a component failure that is repaired in less than 36 hours (MTTR <36). The HR mode, shown in Figure B-1, includes the following three sequences:

- **Pre-Gasifier-Startup = MTTR**: In this case the plant is operating on natgas fuel while the failure is being repaired (baseload operation, no extraction). The net plant power during this time is 90.4-MWe or 92.5% of full plant capacity (97.8-MWe).
- **Extraction of Air from GT-701 = Brief Period (BP)**: In this case the plant is operating on natgas fuel, is baseloaded, but with air extraction from GT-701. The net plant power during this time is 68.5-MWe or 70.0% of full plant capacity.
- **Fuel Crossover = Ramp-Up (RP)**: In this case the plant is ramped up to full capacity, while completing its fuel crossover to syngas. The average net plant power during this time results in an average derating of 83% of full plant capacity.

The average BP hours for all components subject to a HR was calculated as follows:

$$BP = \frac{\text{Total BP hours}}{\text{Total \# of gasification island components subject to an HR}}$$

$$BP = \frac{367.5}{67} = 5.5 \text{ hours}$$

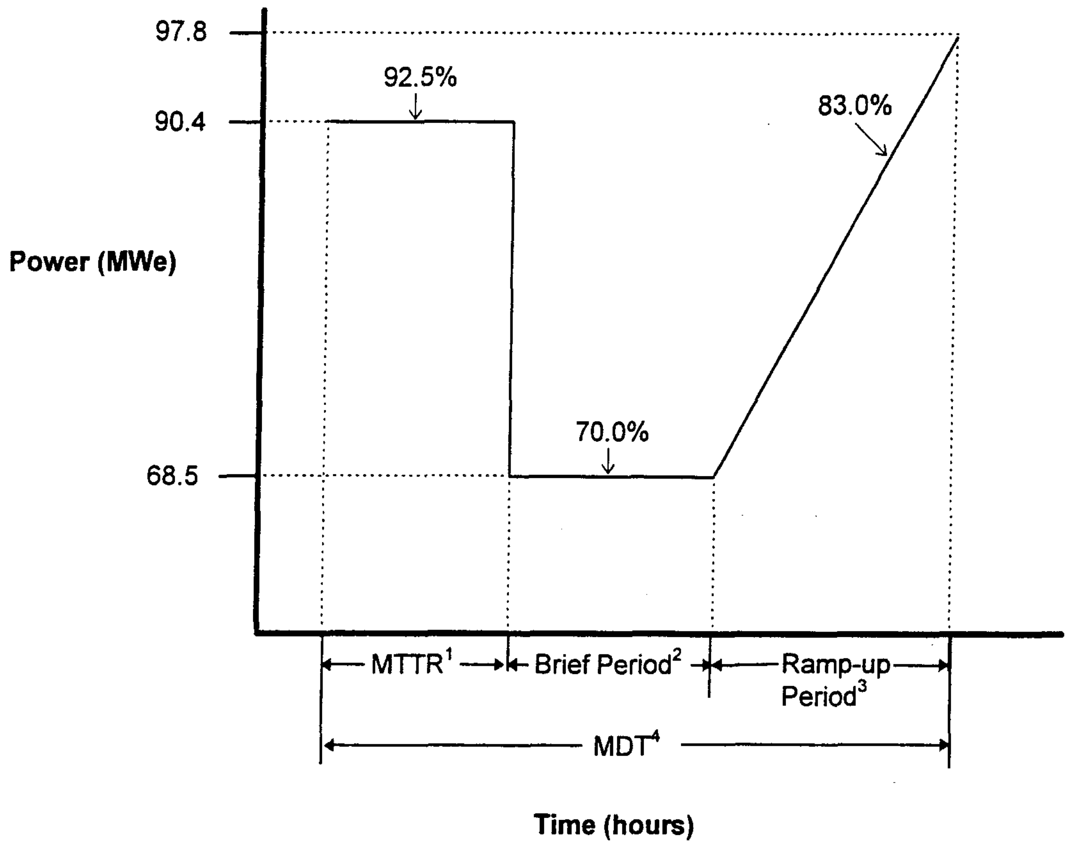
The RP is equal to 6 hours and applies to all components subject to a HR. The time that is associated with the HR derating determines the duration that the plant will operate in a derated state. This time is equal to the sum of the BP and RP hours. This time is calculated as follows:

Total hours subject to a HR derating = 5.5 + 6 = 11.5 hours

The derating for the HR components, based on a weighted average, is calculated as follows:

$$\text{HR Derating} = \frac{5.5}{11.5} \times 70\% + \frac{6}{11.5} \times 83\%$$

$$\text{HR Derating} = 76.8\% \approx 77\%$$



1. The MTTR < 36 hours, and varies for each component that is subject to an HR. During this time, the plant is operating on natgas at 92.5% of full capacity.
2. The average BP time is 5.5 hours, which is the average number of hours per failure. This time is added to the MTTR in order to obtain the MDT. During this time, the plant is operating at 70% of full capacity.
3. The RP is equal to 6 hours, and is the time needed for fuel crossover from natgas to syngas. During this time, the plant is operating at 83% of full capacity.
4. The MDT is the sum of the MTTR, BP hours, and RP hours. This time reflects the total time that the component will be out of service, and varies for each component that is subject to an HR.

Figure B-1. Hot Restart and Fuel Crossover Profile

B.1.1 Components Subject To A Hot Restart

Coal Handling and Receiving

Hoppers BN-101 A/B
Feeders FD-101 A/B
Conveyor CR-102
Storage Dome X-100
I&C Controls
Reclaimer Blower B-116

Coal Crushing and Transport

Stacking Conveyor CR-118
Coal Pile Reclaimer RL-101
Collecting Conveyor CR-105
Feeder FD-114
Diverter DV-105
Screen SE-104
Oversize Conveyor CR-114
Oversize Feeder FD-117
Crusher SR-102 *
Sized Coal Conveyor CR-115
Instrumentation and Controls
Storage Silos BN-105/7 *
Emergency Hopper BN-108
Emergency Feeder

Oxidant Compression and Supply

Control Valves
Compression Bleed Valve
Extraction Air Controls

Gasifier and Feed

Coal Feeder FD-301
Feed Surge Bin BN-301 *
Feed Pressure Hopper BN-302
Feed Hopper BN-303 *
Filters F-301/2 *
Extraction Steam from Steam Turbine PCV
Extraction Steam from HRSG PCV
Gasifier Controls

Control Valves
Limestone and Coal Feeders FD-106/08
Elevating Conveyor CR-110
Solids Feed Line

Gasification Island HRSGs

Gasifier Steam Drum SG-401
H.P. Phosphate Pumps P-1211 A/B/C *
HRSG Gasifier Controls

Gas Treatment and Heat Recovery

Hydraulic Control Module
I&C Controls

Desulfurization

Air Heaters H608 S1/S2
Fines Feeder FD-401 *
I&C Controls
Storage Hopper BN-603
Feed Hopper BN-604 *
Vent Filter F-605
Receive Hopper BN-610 *
Drum Unload System PG-602
Blower C-610
Filter F-610 *

Sulfator and Ash Feed

Limestone Hopper BN-505 *
Vent Filter F-504
I&C Controls
Air Compressor C-601

Fines Combustor

Air Compressor C-602
Screw Feeder FD-503 *
Piping, Feedline Elbows
I&C System Controls

Desulfurized Solids Removal

Fines Bin BN-608 *
Fines Surge Chute BN-608A *
Bag House Screw Conveyor CR-602
Expansion Joints
Solids Transfer Air Dryer DR-601
I&C Transmitter Controls
Bellows

Particulate Removal

HTF Pumps P-501 A/B
HTF Particulate Cooler E-502
Particulate Removal Controls

Solid Waste Removal

Solid Waste Silo BN-1101 *
Vent Filter F-1101
Solid Waste Discharger BV-1101
Slide Gate XV-1101
Exhaust Fan B-1102
Loadout Filter F-1102
Loading Chute CH-1101
Chute Vibrator BV-1102

Recycle Gas

Gas Receiver D-901
Knock-out Drum D-902
Valves
I&C System Controls
Compressor C-902 *

Evaporative Cooler

Evaporative Cooler

Gas Turbine

GT Generator
GT Inlet
GT Combustor
GT Exhaust
GT Controls (MKV)
GT Electrical

GT Accessories & Auxiliaries
GT Fuel Controls

Power Island HRSG

Deaerator DH-801
HRSG Controls
H.P. Phosphate Pumps P-1211 D/C *
L.P. BFW Pumps P-802 A/B
H.P. BFW Pumps P-803 A/B

BFW Makeup and Treatment

Instrumentation and Controls
BFW Treatment
Raw Water Supply Tank/Well
Raw Water Pumps P1202 A/B
Mixed Bed Unit D-1211
Caustic Heater E-1201
Demin. Pumps P-1208 A/B
Demin. Booster Pumps P-1217 A/B
Demin. Regen. Pumps P-1221 A/B
Demin. Acid Pumps P-1203 A/B
Decarbonator T-1201

Steam Turbine Generator

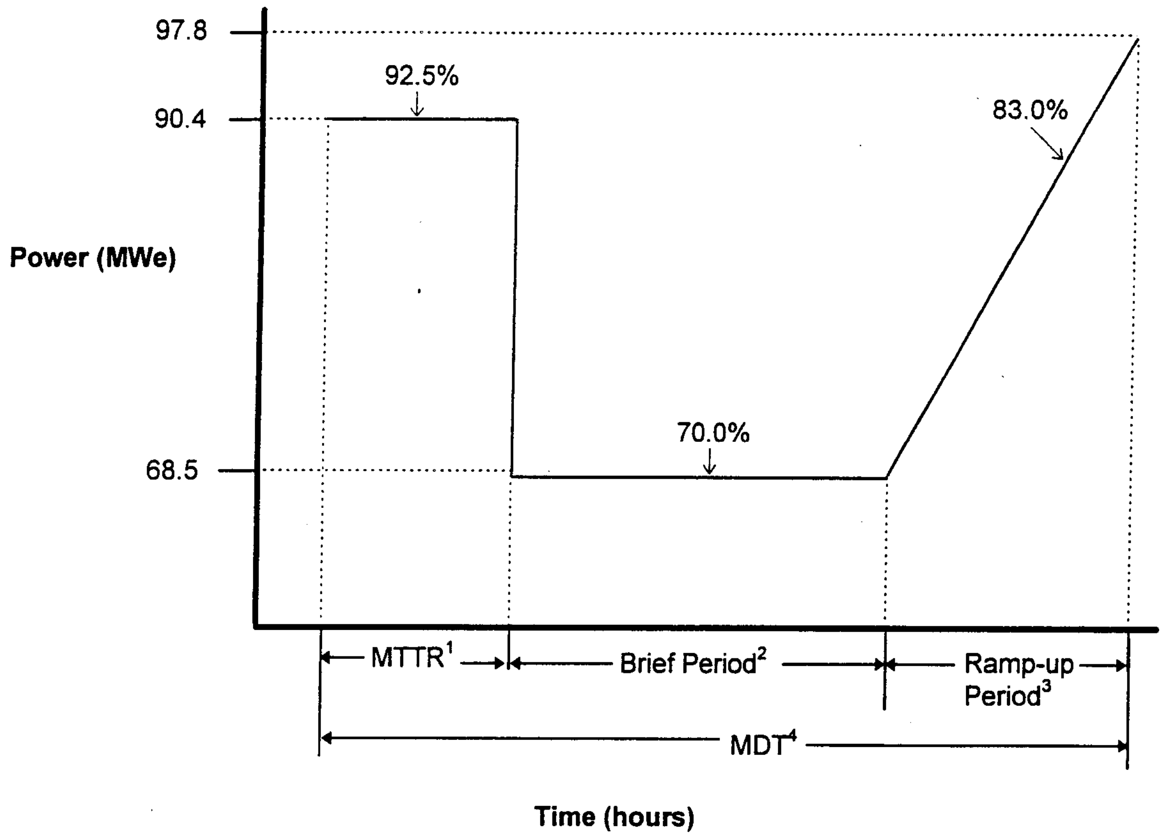
Steam Turbine TG-801
Surface Condenser E-801
Condensate Pumps P-801 A/B
Controls (MKV)
Vacuum Pumps P-804 A/B

Cooling Tower and Condensate Makeup

Cooling Pond Pump P-1201
Circ. Water Treatment *
Cooling Tower Fans
Cooling Water Pumps P-1209 A/B/C
Cooling Tower Controls

Instrument and Plant Air

Air Compressor C-1201 A/B
Air Receiver D-1207



1. The 36 h ≤ MTTR ≥ 68 h, applies to each component that is subject to an IR. During this time, the plant is operating on natgas at 92.5% of full capacity.
2. The BP time is 36.0 hours. This time is added to the MTTR in order to obtain the MDT. During this time, the plant is operating at 70% of full capacity.
3. The RP is equal to 6 hours, and is the time needed for fuel crossover from natgas to syngas. During this time, the plant is operating at 83% of full capacity.
4. The MDT is the sum of the MTTR, BP hours, and RP hours, and varies for each component that is subject to an IR.

Figure B-2. Intermediate Restart Fuel Crossover Profile

B.2.1 Components Subject To An Intermediate Restart

Coal Receiving and Handling

None

Coal Crushing and Transport

None

Oxidant Compression and Supply

Trim Cooler E-202
Compressor C-201
Transport Air Cooler E-204
Knock-out Drum D-201
Air Precooler E-203 S1/S2
Air Recuperator E-201 S1/S2

Gasifier and Feed

Pressurization Compressor C-301 *

Gasification Island HRSGs

HRSG Steam Drum D-602 *
Heat Recovery Steam Generator SG-602 *

Gas Treatment and Heat Recovery

None

Desulfurization

None

Sulfator and Ash Feed

Sulfator Ash Feeder FD-502
Ash Collection Hopper BN-501 *
Ash Depressurization Hopper BN-502
Sulfator Feed Hopper BN-508 *
Rotary Valve FD-302
Filter F-502
Solids Eductor *

Feedline, Elbows
I&C System Controls
I&C Control Valves

Fines Combustor

Collection Hopper BN-503 *
Depressurization Hopper BN-504
Feed Hopper BN-507 *
Fines Vent Filter F-503
I&C Control Valves

Desulfurized Solids Removal

Sulfator Solids Bin BN-607 *

Particulate Removal

Screw Cooler E-501
HTF Tank D-501

Solid Waste Removal

None

Recycle Gas

Trim Cooler E-901

Evaporative Cooler

None

Gas Turbine

None

Power Island HRSG

Steam Drums D-810 1/2
Attemperator DS-801
Desuperheater DS-803
Desuperheater DS-802

BFW Makeup and Treatment

None

Steam Turbine Generator

Generator

Cooling Tower

None

Instrument and Plant Air

None

Electrical Distribution System

Feeder (BD 801/802)
Feeder (BD 701/702)
3.2 K AMP Feeder (BD 805/806)
Feeder (BD 803/804)

Plant Controls

None

Waste Water Treatment

Waste Water Treatment

Catastrophic Events

None

Total Number of Components subject to an Intermediate Restart = 41.

* Represents Components having a failure rate (FR) greater than 10^{-4} failures per year.

B.3 CALCULATION OF AVERAGE PLANT DERATING DUE TO A COLD RESTART (CR)

The CR derating considers the ability of the plant to return to syngas after a component failure that is repaired in a time greater than 68 hours (MTTR > 68 h). The CR mode, shown in Figure B-3, includes the following three sequences:

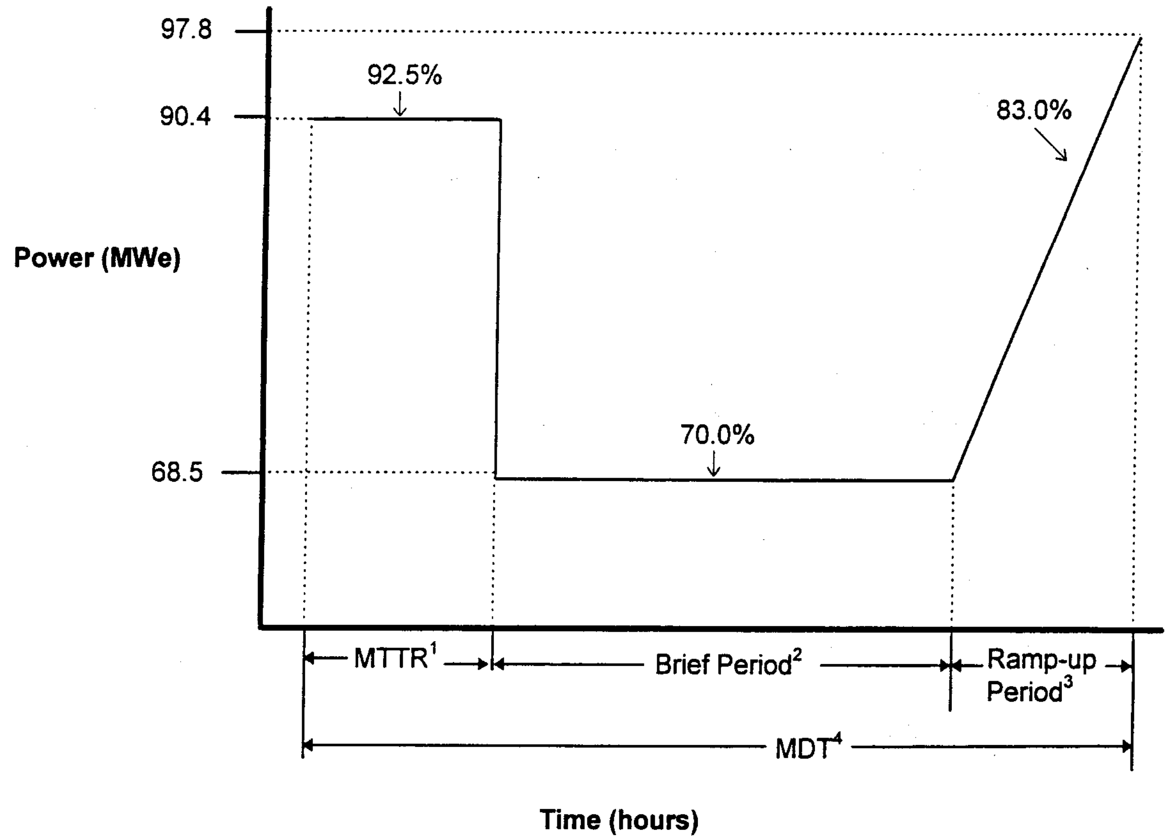
- **Pre-Gasifier Startup = MTTR**: In this case the plant is operating on natgas fuel while the failure is being repaired (baseloaded operation, no extraction). The net plant power during this time is 90.4-MWe or 92.5% of full plant capacity (97.8-MWe).
- **Extraction of Air from GT-701 = Brief Period (BP)**: In this case the plant is operating on natgas fuel, is baseloaded, but with air extraction from GT-701. The net plant power during this time is 68.5-MWe or 70% of full plant capacity.
- **Fuel Crossover = Ramp-up (RP)**: In this case the plant is ramped up to full capacity, while completing its fuel crossover to syngas. The average net plant power during this time results in an average derating of 83% of full plant capacity.

The BP time for each component is equal to 132 hours. Together, the MTTR and BP hours are equal to the MDT. The RP is equal to 10 hours and applies to all components subject to a CR. The time associated with the CR derating determines the duration of plant operation in a CR derated state. This time is equal to the sum of the BP and RP hours, which is equal to 132 + 10 or 142 hours.

From the BP and RP hours, the derating for each CR is calculated as follows:

$$\text{CR Derating} = \frac{132}{142} \times 70\% + \frac{10}{142} \times 83\%$$

$$\text{CR Derating} = 71\%$$



1. The MTTR > 68 h, applies to each component that is subject to a hot restart. During this time, the plant is operating on natgas at 92.5% of full capacity.
2. The BP time is 132 hours. This time is added to the MTTR in order to obtain the MDT. During this time, the plant is operating at 70% of full capacity.
3. The RP is equal to 10 hours, and is the time needed for fuel crossover from natgas to syngas. During this time, the plant is operating at 83% of full capacity.
4. The MDT is the sum of the MTTR, BP hours, and RP hours. This time reflects the total time that the component will be out of service, and varies for each component that is subject to a CR.

Figure B-3. Cold Restart Fuel Crossover Profile

B.3.1 Components Subject To A Cold Restart

Coal Receiving and Handling

None

Coal Crushing and Transport

None

Oxidant Compression and Supply

None

Gasifier and Feed

Gasifier Refractory Liner R-301
Cyclone Refractory Liner S-301
Gasifier Feed Tube
Annulus Refractory
Air Receiver D-301
Gasifier Vessel R-301
Valve, Solids Isolation

Gasification Island HRSGs

None

Gas Treatment and Heat Recovery

Product Gas Cooler E-401
Product Gas Trimmer E-403
Valve TV0071
Valve PD070

Desulfurization

Regenerator Effluent Cooler E-607
Refractory Cyclone S-603
Refractory Cyclone S-604
Desulfurized Feed Cyclone S-401
Desulfurizer Refractory R-603
Regenerator Refractory R-604
Piping Refractory
Piping, Valves Solids

Sulfator and Ash Feed

Sulfator Reactor R-602 *
Sulfator Cyclone S-601
Solids Cooler E-605
Piping Refractory
Valves, Solids Isolation

Fines Combustor

Fines Combustor H-602 *

Desulfurized Solids Removal

Screw Cooler E-602
Collection Hopper BN-601
Flue Gas Bag House Filter F-602 *

Particulate Removal

Hot Gas Filter Refractory F-501
Hot Gas Filter Elements F-501

Solid Waste Removal

None

Recycle Gas

Gas Compressor C-901
Gas Cooler E-402 S1/S2

Evaporative Cooler

None

Gas Turbine

GT Compressor
GT Turbine/Bearings

Power Island HRSG

HRSG SG-801

BFW Makeup and Treatment

Anion/Cation Units D-1204/03

Steam Turbine Generator

None

Cooling Tower

Three Cell Cooling Tower CT-1201

Instrument and Plant Air

None

Electrical Distribution System

4.16/0.48 KV XFMR (TR803)
4.16/0.48 KV XFMR (TR804)
120/13.8 KV XFMR (TR801)
13.2/4.16 KV XFMR (TR802)
13.2/4.16 XFMR (TR702)
120/13.8 KV XFMR (TR701)
4.16/0.48 KV XFMR (TR806)
4.16/0.48 KV XFMR (TR805)

Plant Controls

None

Waste Water Treatment

None

Catastrophic Events

Fire/Explosion

Total Number of Components subject to a Cold Restart = 47

* Represents Components having a failure rate (FR) greater than 10^{-4} failures per year.

B.4 CALCULATION OF THE PLANT SCHEDULED OUTAGE HOURS

The scheduled maintenance plan discussed in Section 2 assumes that the gasification island maintenance is performed concurrently with GT scheduled maintenance, wherever possible, to minimize plant downtime. Scheduled maintenance is assumed to be performed on a six-year repeating cycle as shown in Table B-4, which reflects current industry practices for General Electric "E" and "F" model GTs (ref.11).

Table B-4. Piñon Pine Scheduled Maintenance

Year	Task	Duration (Hours)	Extensions (Hours)	SOH (1)	EOH_1 (2)	EOH_2 (3)	ESOH (4)	Annual SOH (5)
1,2,4&5	GT Combustion Inspection	48	8	62	4.4	41.3	107.7	71.8
3	GT Hot Gas-Path Inspection	158	24	198	0	41.3	239.3	39.9
6	GT/Generator Major Overhaul	456	24	528	0	41.3	569.3	94.9
6	ST/Generator Major Overhaul	*	*	*	*	*	*	-
							Total	207 h

* Performed concurrently with the GT overhaul.

(1) Scheduled Outage Hours (SOH): These are the hours needed to perform the indicated inspection, which assumes two 12-hour shifts per day, unlimited labor and spares. Hours indicate 100% loss of plant capacity (97.8-MWe) for the scheduled duration, plus extensions, plus a 10% contingency. During the 62-hours allowed for the combustion inspection, the gasification island will be in the cooldown mode.

(2) Equivalent Outage Hours (EOH_1): This outage is due to gasification island maintenance overlapping the time required for the indicated inspection. Includes the gasification island cooldown hours less the hours for a combustion inspection, 62 hours - 48 hours = 14 hours plus 58 hours for gasification island maintenance. During this time the plant will be operating on natural gas at a 7.5% derating. $EOH_1 = 58\ h \times 7.5\% = 4.4$ hours.

(3) Equivalent Outage Hours (EOH_2): This is due to cold restart delay time after the inspection has been completed. $EOH_2 = (132\ \text{hours} \times 30\%) + (10\ \text{hours} \times 17\%) = 41.3$ hours (See Appendix B, Section B-4).

(4) Equivalent Scheduled Outage Hours (ESOH): These hours indicate 100% loss of plant capacity for the equivalent hours associated with each inspection. ESOH = SOH + Extensions + EOH.

(5) Annual Equivalent Scheduled Outage Hours (ESOH): These hours also indicate 100% loss of plant capacity for the equivalent hours associated with each inspection if averaged over a six-year cycle.

Annual combustion inspections and gasification island maintenance will be performed concurrently, except in years 3 and 6. During these years, the hot-gas path inspection will be performed. The major overhaul will be performed in year 6, after which the 6-year cycle repeats. The durations shown in this table are typical of aggressive industry practices and recent data from the Kern River Cogeneration Plant (ref.11). The plan assumes that General Electric staff will assist the plant staff during the scheduled maintenance.

The removal and replacement of overhead piping and structures (see Figure B-4) will extend these durations by the values noted in the column "Extensions" in Table B-4. The equivalent outage hours (EOH) shown for each task represent the equivalent hours lost at full plant capacity considering the plant deratings and the following procedures necessary to complete the annual scheduled maintenance and fuel transfer process (RP) shown in Figure B-3.

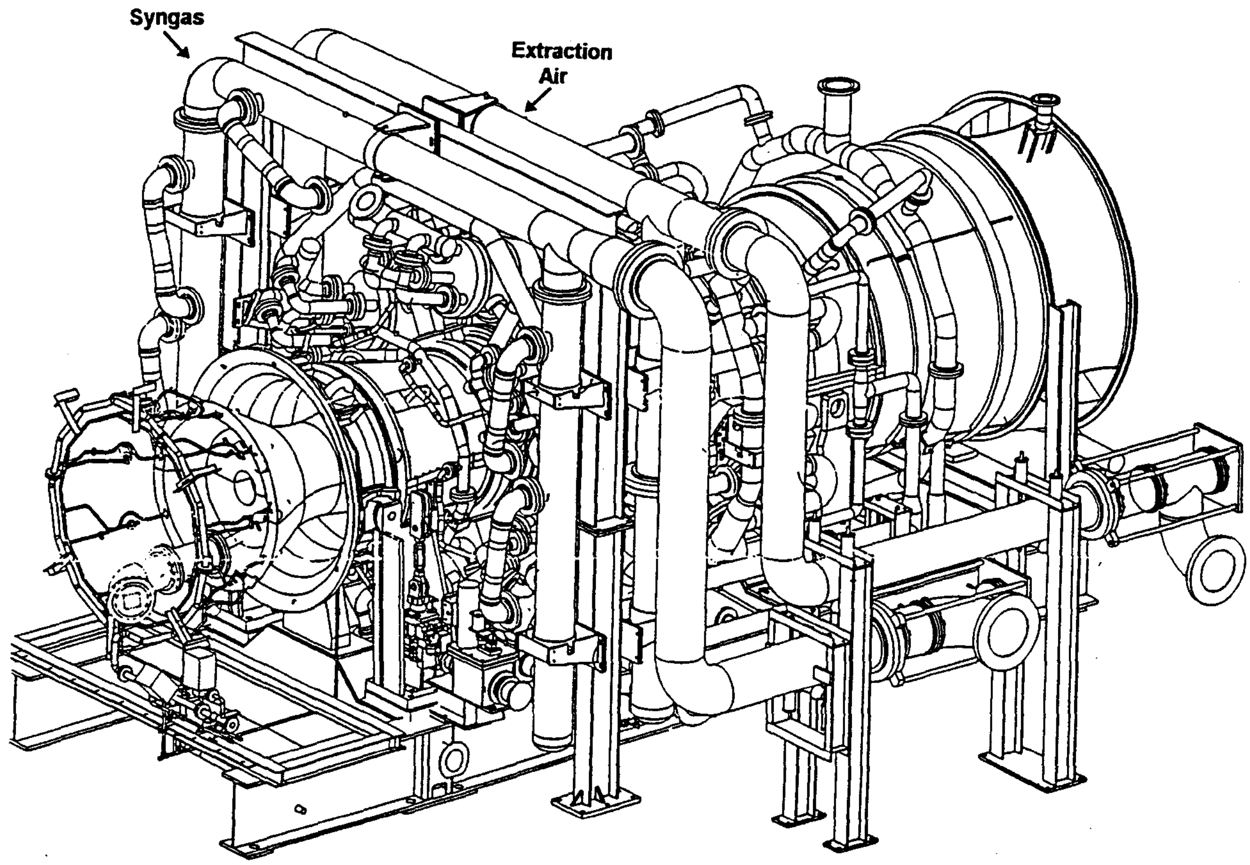


Figure B-4. Overhead Piping and Structures for the GT-701

B.4.1 Example procedure for a typical GT Combustion Inspection:

1. The GT is removed from service.
2. The gasification island begins the cool-down process, which lasts for two days (48 h). This rapid cool down of the gasification island is accomplished by utilizing the recycle gas compressors to transfer bed heat into exchangers E401/E403 and then E402. This also allows cooling of the bed material as it is emptied through to the sulfator (ref.14).
3. During the cooldown of the gasification island, the GT inspection is performed, and lasts for approximately 2.6 days (62 h).
4. After the gasification island has cooled down completely, the gasification island maintenance and inspection begins, which is assumed to require 3 days (72 hours) downtime.
5. Following completion of the GT combustion inspection, the plant is started on natural gas (natgas) at a 7.5% derating (90.4-MWe).
6. The plant continues to operate in the natgas mode while the gasification island maintenance and inspection continues for 2.4 days (58 h).
7. After all maintenance and inspections are completed, the plant returns to the syngas mode according to Figure B-3.

B.4.2 Calculation of Annual GT Combustion Inspection Hours:

SOH = 62 h
EOH = 58 h × 7.5% = 4.4 h
EOH = (132 h × 30%) + (10 h × 17%) = 41.3
ESOH = 62 h + 4.4 h + 41.3 = 107.7 h
Annual ESOH = $^4/_6$ × 107.7 h = 71.8 h

B.4.3 Calculation of Hot Gas-Path Inspection Hours:

SOH = 198 h
EOH = 0 h
EOH = (132 h × 30%) + (10 h × 17%) = 41.3
ESOH = 198 h + 41.3 h = 239.3 h
Annual ESOH = $^1/_6$ × 239.3 h = 39.9 h

B.4.4 Calculation of a Major Overhaul

Major Overhaul = 528 h
EOH = 0 h
EOH = (132 h × 30%) + (10 h × 17%) = 41.3
ESOH = 528 h + 41.3 h = 569.3 h
Annual ESOH = $^1/_6$ × 569.3 h = 94.9 h

From the above calculations, the annual SOH for the entire facility is calculated to be 207 hours (see Table B-4). This value represents a 2.4 % loss in equivalent availability (EA) as it pertains to the IGCC mode operation. The scheduled maintenance hours by year is shown in Table B-5.

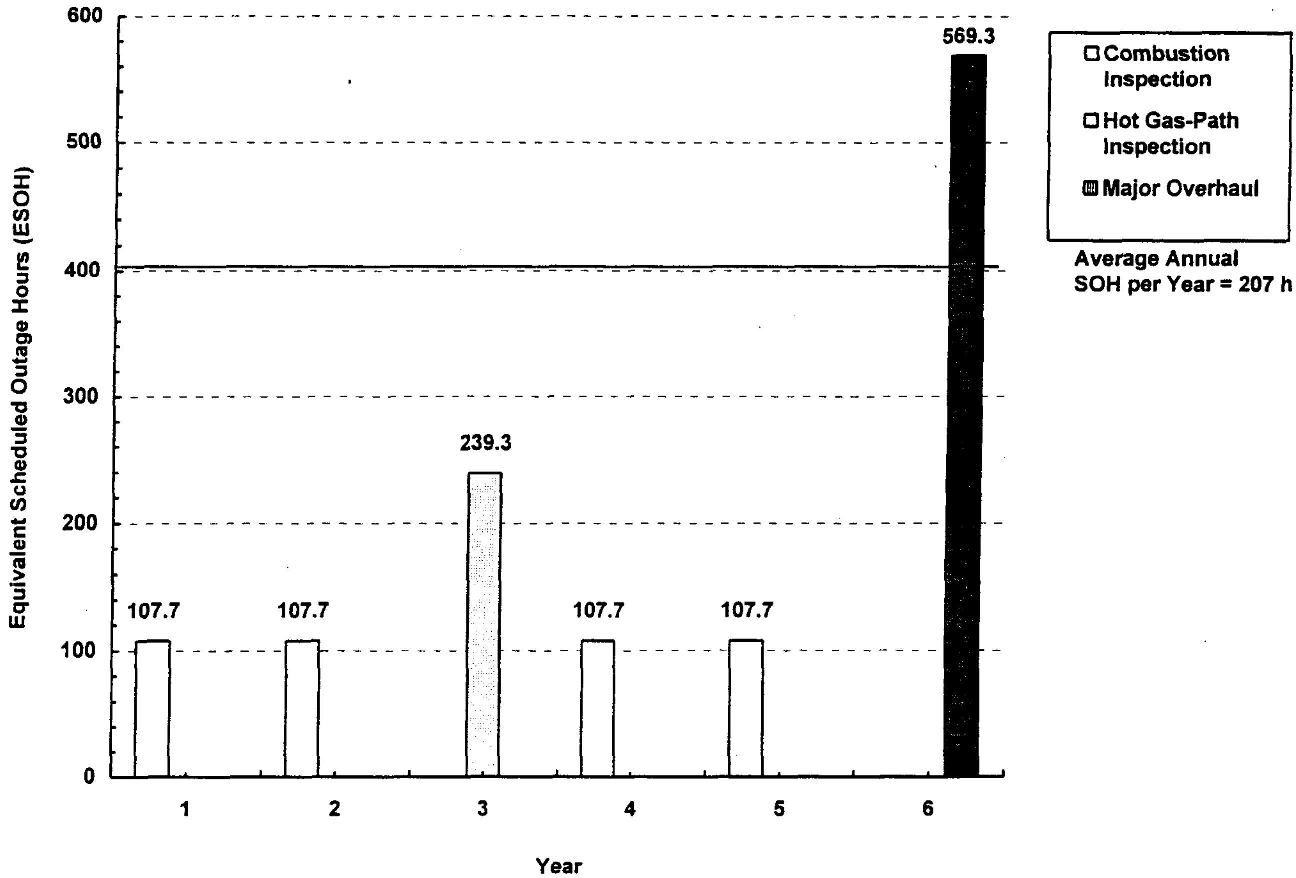


Figure B-5. Piñon Pine Scheduled Maintenance Hours

APPENDIX C

UNIRAM DATA INPUT FILE AND EXECUTION RUNS

This Appendix contains the input file and exedution runs that pertain to the IGCC Piñion Pine UNIRAM model.

```
SYNATBPS.UNI
207.00 0.00 100.00 8760.00
35
COAL RECEIVE/STORE ....................[1]
100.0 1.0 8 5 0.00
-1 0 0.0
-1 1 0.0
-1 2 0.0
-1 2 0.0
-1 1 0.0
INSTRUMENT/CONTROLS
1 1 15150.0 1 6.0 480.00 0.00 1
CONVEYOR: CR102
1 1 16053.0 1 16.0 480.00 0.00 1
COAL BIN: BN101A
3 1 41512.0 1 20.0 480.00 0.00 1
COAL BIN: 101B
3 1 41512.0 1 20.0 480.00 0.00 1
COAL FEEDER: FD101A
4 1 29193.0 1 16.0 480.00 0.00 1
COAL FEEDER: FD101B
4 1 29193.0 1 16.0 480.00 0.00 1
RECL BLOWER: B116
5 1 166666.0 1 28.0 480.00 0.00 1
STORE DOME: X100
5 1 999999.0 1 20.0 480.00 0.00 1
COAL CRUSH/TRANSPORT ..................[2]
100.0 1.0 15 6 0.00
-1 0 0.0
-1 1 0.0
1 1 0.0
-1 3 0.0
-1 1 0.0
-1 5 0.0
EMER HOPPER: BN108
4 1 41512.0 1 20.0 24.00 0.00 1
EMER FEEDER:
4 1 17510.0 1 8.0 24.00 0.00 1
VIBR FEEDER: FD114
3 1 17510.0 1 8.0 24.00 0.00 1
CONVEYOR: CR118
2 1 19158.0 1 30.0 24.00 0.00 1
RECLAIMER: RL101
2 1 32120.0 1 10.0 24.00 0.00 1
COL CONVEYOR: CR105
1 1 16053.0 1 16.0 24.00 0.00 1
OVER CONVEYOR: CR114
6 1 16053.0 1 16.0 24.00 0.00 1
SIZE CONVEYOR: CR115
6 1 16053.0 1 16.0 24.00 0.00 1
OVERSIZE FEED: FD117
5 1 17510.0 1 8.0 24.00 0.00 1
DIVERTER: DV105
5 1 17500.0 1 3.0 24.00 0.00 1
SCREEN: SE104
5 1 28280.0 1 18.0 24.00 0.00 1
CRUSHER: SR102
5 1 8760.0 1 28.0 24.00 0.00 1
LIME BIN: BN107
1 1 9495.0 1 4.0 144.00 0.00 1
COAL BIN: BN105
1 1 9495.0 1 4.0 24.00 0.00 1
INSTRUMENT/CONTROLS
1 1 15150.0 1 6.0 24.00 0.00 1
COAL C/T DERATING......................[3]
97.0 1.0 1 0 0.00
REDUCED CAPACITY STATE
0 1 99999999.0 1 0.01 0.00 0.00 1
OXIDANT COMPRESS.......................[4]
100.0 1.0 11 4 0.00
-1 0 0.0
-1 1 0.0
-1 1 0.0
-1 1 0.0
EXTRACT AIR CONTROLS
2 1 15150.0 1 6.0 0.00 0.00 1
COMPRESS BLEED VALVE
2 1 183486.0 1 4.0 0.00 0.00 1
AIR PRECOOL: E203S1
3 1 97000.0 1 21.0 0.00 0.00 1
```

```
AIR PRECOOL: E203S2
3 1 97000.0 1 21.0 0.00 0.00 1
AIR RECUPER: E201S1
4 1 97000.0 1 21.0 0.00 0.00 1
AIR RECUPER: E201S2
4 1 97000.0 1 21.0 0.00 0.00 1
TRIM COOLER: E202
1 1 97000.0 1 21.0 0.00 0.00 1
CONTROL VALVES
1 1 27100.0 1 5.0 0.00 0.00 1
BST COMPRESSOR: C201
1 1 26280.0 1 40.0 0.00 0.00 1
AIR COOLER: E204
1 1 97000.0 1 21.0 0.00 0.00 1
KO DRUM: D201
1 1 91000.0 1 20.0 0.00 0.00 1
GASIFIER/FEED..........................[5]
100.0 1.0 22 5 0.00
-1 0 0.0
1 1 0.0
-1 1 0.0
-1 3 0.0
-1 3 0.0
STEAM TURBINE PCV
2 1 348432.0 1 4.0 0.00 0.00 1
HRSG PCV
2 1 348432.0 1 4.0 0.00 0.00 1
FILTER: F301
4 1 13140.0 1 6.0 0.00 0.00 1
FILTER: F302
4 1 7620.0 1 2.0 0.00 0.00 1
COAL FEEDER: FD301
3 1 17520.0 1 8.0 0.00 0.00 1
COMPRESSOR: C301
3 1 6000.0 1 30.0 0.00 0.00 1
AIR RECEIVER: D301
3 1 90000.0 1 25.0 0.00 0.00 1
SURGE BIN: BN301
3 1 6410.0 1 2.0 0.0 0.00 1
PRESS HOPPER: BN302
3 1 10970.0 1 7.0 0.0 0.00 1
FEED HOPPER: BN303
3 1 9320.0 1 8.0 0.0 0.00 1
I&C GASIFIER CONTROLS
1 1 15150.0 1 3.0 0.00 0.00 1
CYCLONE REFRACTORY: S301
1 1 52560.0 1 120.0 0.00 0.00 1
GASIFIER FEED TUBE
1 1 13140.0 1 52.0 0.00 0.00 1
I&C CONTROL VALVES
1 1 29411.0 1 4.0 0.00 0.00 1
ANNULUS REFRACTROY
1 1 52560.0 1 490.0 0.00 0.00 1
GASIF REFRACTORY: R301
1 1 105120.0 1 1110.0 0.00 0.00 1
LIME FEEDER: FD108
5 1 17150.0 1 8.0 0.00 0.00 1
COAL FEEDER: FD106
5 1 17510.0 1 8.0 0.00 0.00 1
CONVEYOR: CR110
3 1 16053.0 1 8.0 0.00 0.00 1
GASIFIER VESSEL
1 1 219000.0 1 360.0 0.00 0.00 1
SOLIDS FEED LINE
3 1 26280.0 1 3.0 0.00 0.00 1
VALVE, SOLIDS ISOLATION
3 1 26280.0 1 3.0 0.00 0.00 1
HRSG: GASIF. ISLAND....................[6]
100.0 1.0 7 3 0.00
-1 0 0.0
-1 1 0.0
-2 1 0.0
GASIF ST DRUM: SG401
2 1 66667.0 1 16.0 0.00 0.00 1
HRSG: SG602
2 1 8760.0 1 48.0 0.00 0.00 1
H.P. PHOS: P1211A
3 1 8652.0 1 5.0 0.00 0.00 1
H.P. PHOS: P1211B
3 1 8652.0 1 5.0 0.00 0.00 1
```

```
SPARE PHOS: P1211C
3 1 8652.0 1 5.0 0.00 0.00 1
HRSG GASIF CONTROLS
1 1 15150.0 1 6.0 0.00 0.00 1
HRSG DRUM: D602
1 1 8760.0 1 48.0 0.00 0.00 1
GAS TREAT/HEAT RECOV ..................[7]
100.0 1.0 6 3 0.00
-1 0 0.0
-1 1 0.0
-1 1 0.0
GAS COOLER: E401
2 1 43800.0 1 60.0 0.00 0.00 1
GAS TRIMMER: E403
2 1 43800.0 1 60.0 0.00 0.00 1
HYD CONTROLS: HC100
1 1 63735.0 1 3.0 0.00 0.00 1
I&C CONTROLS
1 1 15150.0 1 2.0 0.00 0.00 1
VALVE TV0071
3 1 26280.0 1 6.0 0.00 0.00 1
VALVE PDV070
3 1 26280.0 1 6.0 0.00 0.00 1
DESULFURIZATION.........................[8]
100.0 1.0 19 6 0.00
-1 0 0.0
-1 1 0.0
-1 1 0.0
-1 3 0.0
-1 1 0.0
-1 1 0.0
REGEN HEATER: H608S1
2 1 33288.0 1 22.0 0.00 0.00 1
REGEN HEATER: H608S2
2 1 33288.0 1 22.0 0.00 0.00 1
FINES FEED: FD401
4 1 1610.0 1 4.0 0.00 0.00 1
REFRACTORY CYCLONE: S401
4 1 52560.0 1 180.0 0.00 0.00 1
REFRACTORY CYCLONE: S603
3 1 52560.0 1 180.0 0.00 0.00 1
REFRACTORY CYCLONE: S604
3 1 52560.0 1 180.0 0.00 0.00 1
STORE HOPPER: BN603
5 1 26280.0 1 3.0 0.00 0.00 1
FEED HOPPER: BN604
5 1 8224.0 1 5.0 0.00 0.00 1
VENT FILTER: F605
5 1 13140.0 1 4.0 0.00 0.00 1
REC HOPPER: BN610
5 1 6482.0 1 5.0 480.00 0.00 1
DRUM UNLD: PG602
5 1 133333.0 1 13.0 0.00 0.00 1
DESULF REFRACTORY: R603
6 1 52560.0 1 180.0 0.00 0.00 1
REGEN REFRACTORY: R604
6 1 52560.0 1 180.0 0.00 0.00 1
REGEN COOLER: E607
1 1 35055.0 1 60.0 0.00 0.00 1
I&C CONTROLS
1 1 15150.0 1 3.0 0.00 0.00 1
PIPE REFRACTORY
1 1 105120.0 1 180.0 0.00 0.00 1
PIPING, VALVE SOLIDS
1 1 26280.0 1 8.0 0.00 0.00 1
BLOWER: C610
1 1 10520.0 1 4.0 0.00 0.00 1
FILTER: F610
1 1 2000.0 1 0.5 0.00 0.00 1
SULFATOR/ASH FEED......................[9]
100.0 1.0 19 3 0.00
-1 0 0.0
-1 1 0.0
-1 1 0.0
LIME HOPPER: BN505
2 1 8423.0 1 4.0 0.00 0.00 1
VENT FILTER: F504
2 1 13140.0 1 4.0 0.00 0.00 1
I&C SULFATOR CONTROLS
3 1 15150.0 1 3.0 0.00 0.00 1
```

```
ASH FEEDER: FD502
3 1 17520.0 1 8.0 0.00 0.00 1
FEED HOPPER: BN508
3 1 9320.0 1 8.0 0.00 0.00 1
COLL HOPPER: BN501
3 1 8760.0 1 2.0 0.00 0.00 1
DEPRES HOPPER: BN502
3 1 10970.0 1 7.0 0.00 0.00 1
GAS ASH FEED: FD302
3 1 13140.0 1 4.0 0.00 0.00 1
VENT FILTER: F502
3 1 13140.0 1 20.0 0.00 0.00 1
SULF REACTOR: R602
1 1 1700.0 1 60.0 0.00 0.00 1
SULF CYCLONE: S601
1 1 87600.0 1 120.0 0.00 0.00 1
SULF COMPRESS: C601
1 1 26280.0 1 21.0 0.00 0.00 1
SOLIDS COOLER: E605
1 1 36959.0 1 23.0 0.00 0.00 1
I&C SYSTEM CONTROLS
1 1 15150.0 1 4.0 0.00 0.00 1
PIPE REFRACTORY
1 1 105120.0 1 120.0 0.00 0.00 1
VALVES, SOLIDS ISOLATION
1 1 43800.0 1 4.0 0.00 0.00 1
SOLIDS EDUCTOR
1 1 8760.0 1 4.0 0.00 0.00 1
FEEDLINE ELBOWS
1 1 26280.0 1 4.0 0.00 0.00 1
I&C CONTROL VALVES
1 1 15150.0 1 4.0 0.00 0.00 1
FINES COMBUSTOR.........................[10]
100.0 1.0 10 2 0.00
-1 0 0.0
-1 1 0.0
FEED HOPPER: BN507
2 1 9320.0 1 8.0 0.00 0.00 1
COLL HOPPER: BN503
2 1 8760.0 1 2.0 0.00 0.00 1
DEPRES HOPPER: BN504
2 1 10970.0 1 7.0 0.00 0.00 1
FINES FEEDER: FD503
2 1 1610.0 1 4.0 0.00 0.00 1
VENT FILTER: F503
2 1 13140.0 1 20.0 0.00 0.00 1
COMBUSTOR: H602 (system)
1 1 5205.0 1 41.0 0.00 0.00 1
I&C SYSTEM CONTROLS
1 1 15150.0 1 3.0 0.00 0.00 1
BLOWER: C602
1 1 17520.0 1 8.0 0.00 0.00 1
I&C CONTROL VALVES
1 1 15140.0 1 4.0 0.00 0.00 1
PIPING FEEDLINE ELBOWS
1 1 87600.0 1 4.0 0.00 0.00 1
DESULF SOLID REMOVAL...................[11]
100.0 1.0 11 2 0.00
-1 0 0.0
-1 1 0.0
SULF SOL BIN: BN607
2 1 7920.0 1 4.0 0.00 0.00 1
FINES BIN: BN608
2 1 7920.0 1 4.0 0.00 0.00 1
FINES CHUTE: BN 608A
2 1 6482.0 1 8.0 0.00 0.00 1
SCREW COOLER: E602
1 1 36959.0 1 8.0 0.00 0.00 1
COLL HOPPER: BN601
1 1 219000.0 1 60.0 0.00 0.00 1
SCR CONVEYOR: CR602
1 1 26280.0 1 16.0 0.00 0.00 1
EXPANSION JOINTS
1 1 40000.0 1 15.0 0.00 0.00 1
AIR DRYER: DR601
1 1 133333.0 1 13.0 0.00 0.00 1
BAG FILTER: F602
1 1 8760.0 1 24.0 0.00 0.00 1
I&C TRANSMIT CONTROLS
1 1 15150.0 1 3.0 0.00 0.00 1
```

```
BELLOWS
1 1 40000.0 1 15.0 0.00 0.00 1
PARTICULATE REMOVAL....................[12]
100.0 1.0 8 4 0.00
-1 0 0.0
-1 1 0.0
1 2 0.0
-1 1 0.0
HOT GAS FILTER REFRACTROY: F501
4 1 105120.0 1 120.0 0.00 0.00 1
HOT GAS FILTER ELEMENTS: F501
4 1 26280.0 1 160.0 0.00 0.00 1
HTF PUMP: P501A
3 1 18479.0 1 8.0 0.00 0.00 1
HTF PUMP: P501B
3 1 18479.0 1 8.0 0.00 0.00 1
PART COOLER: E502
2 1 36959.0 1 8.0 0.00 0.00 1
SCREW COOLER: E501
1 1 36959.0 1 8.0 0.00 0.00 1
PART REMOV CONTROLS
1 1 15150.0 1 3.0 0.00 0.00 1
HTF TANK: D501
2 1 219000.0 1 36.0 0.00 0.00 1
SOLID WASTE REMOVAL....................[13]
100.0 1.0 8 2 0.00
-1 0 0.0
-1 1 0.0
SLIDE GATE: XV1101
2 1 133333.0 1 13.0 24.00 0.00 1
EXHAUST FAN: B1102
2 1 166666.0 1 28.0 24.00 0.00 1
LDOUT FILTER: F1102
2 1 13140.0 1 4.0 24.00 0.00 1
LOAD CHUTE: CH1101
2 1 17500.0 1 3.0 24.00 0.00 1
CHUTE VIBR: BV1102
2 1 17500.0 1 3.0 24.00 0.00 1
WASTE SILO: BN1101
1 1 9495.0 1 4.0 24.00 0.00 1
VENT FILTER: F1101
1 1 13140.0 1 4.0 24.00 0.00 1
DISCHARGER: BV1101
1 1 133333.0 1 13.0 24.00 0.00 1
RECYCLE GAS............................[14]
100.0 1.0 9 4 0.00
-1 0 0.0
-1 1 0.0
-1 1 0.0
-1 1 0.0
KO DRUM: D902
2 1 91110.0 1 18.0 0.00 0.00 1
RECEIVER: D901
2 1 91100.0 1 18.0 0.00 0.00 1
COMPRESSOR: C901
3 1 15140.0 1 34.0 0.00 0.00 1
COMPRESSOR: C902
3 1 6000.0 1 30.0 0.00 0.00 1
GAS COOLER: E402S1
4 1 219000.0 1 103.0 0.00 0.00 1
GAS COOLER: E402S2
4 1 219000.0 1 103.0 0.00 0.00 1
TRIM COOLER: E901
1 1 33288.0 1 36.0 0.00 0.00 1
VALVES, PULSE GAS
1 1 17520.0 1 2.0 0.00 0.00 1
I&C SYSTEM CONTROLS
1 1 15150.0 1 3.0 0.00 0.00 1
EVAPORATIVE COOLER.....................[15]
100.0 1.0 1 0 0.00
EVAPORATIVE COOLER
0 1 33200.0 1 35.0 0.00 0.00 1
EVAP COOLER DERATING...................[16]
96.0 1.0 1 0 0.00
EVAP COOLER DERATING
0 1 99999999.0 1 0.01 0.00 0.00 1
GAS TURBINE/GENERATR...................[17]
100.0 1.0 10 1 0.00
-1 0 0.0
GT GENERATOR
```

```
1 1 11948.0 1 31.0 0.00 0.00 1
GT INLET
1 1 43312.0 1 11.0 0.00 0.00 1
GT COMPRESSOR
1 1 30194.0 1 230.0 0.00 0.00 1
TURBINE/BEARINGS
1 1 51108.0 1 237.0 0.00 0.00 1
GT COMBUSTOR
1 1 22700.0 1 18.0 0.00 0.00 1
GT FUEL CONTROLS
1 1 59772.0 1 3.0 0.00 0.00 1
GT EXHAUST
1 1 60933.0 1 35.0 0.00 0.00 1
GT CONTROLS (MKIV)
1 1 30607.0 1 2.0 0.00 0.00 1
GT ELECTRICAL
1 1 14250.0 1 25.0 0.00 0.00 1
GT ACCESS/AUXILIAR
1 1 6296.0 1 9.0 0.00 0.00 1
HRSG POWER ISLAND.......................[18]
100.0 1.0 14 6 0.00
-1 0 0.0
1 1 0.0
-1 1 0.0
1 3 0.0
1 3 0.0
-1 1 0.0
H.P. PHOS: P1211D
2 1 8652.0 1 5.0 0.00 0.00 1
H.P. PHOS: P1211C
2 1 8652.0 1 5.0 0.00 0.00 1
L.P. BFW: P802A
4 1 31882.0 1 26.0 0.00 0.00 1
L.P. BFW: P802B
4 1 31882.0 1 26.0 0.00 0.00 1
H.P. BFW: P803A
5 1 31882.0 1 26.0 0.00 0.00 1
H.P. BFW: P803B
5 1 31882.0 1 26.0 0.00 0.00 1
H.P. DRUM: D801
6 1 66667.0 1 39.0 0.00 0.00 1
L.P. DRUM: D802
6 1 66667.0 1 39.0 0.00 0.00 1
HRSG: SG801
1 1 15140.0 1 105.0 0.00 0.00 1
ATTEMPERATOR: DS801
1 1 438000.0 1 49.0 0.00 0.00 1
DEAERATOR: DH801
1 1 71800.0 1 30.0 0.00 0.00 1
M.P. DESUPHTR: DS802
1 1 438000.0 1 49.0 0.00 0.00 1
PEG DESUPHTR: DS803
1 1 438000.0 1 49.0 0.00 0.00 1
HRSG CONTROLS
1 1 23052.0 1 8.0 0.00 0.00 1
BFW MAKEUP/TREATMENT...................[19]
100.0 1.0 14 10 0.00
-1 0 0.0
-1 1 0.0
-1 2 0.0
1 1 0.0
1 1 0.0
2 2 0.0
2 3 0.0
2 3 0.0
2 3 0.0
2 3 0.0
BOOST PUMP: P1217A/B
7 1 16650.0 1 13.0 0.00 0.00 1
DEMIN PUMP: P1208A/B
8 1 16650.0 1 13.0 0.00 0.00 1
REGEN PUMP: P1221A/B
9 1 16650.0 1 13.0 0.00 0.00 1
ACID PUMP: P1203A/B
10 1 16650.0 1 13.0 0.00 0.00 1
AN/CAT: D1204/03
6 1 12640.0 1 70.0 0.00 0.00 1
MIX BED: D1211
2 1 87600.0 1 6.0 0.00 0.00 1
CAUS HEATER: E1201
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2 1 100000.0 1 3.0 0.00 0.00 1
DECARBONATOR: T1201
2 1 1333333.0 1 13.0 0.00 0.00 1
TANK
4 1 33000.0 1 13.0 0.00 0.00 1
WELL
4 1 33000.0 1 13.0 0.00 0.00 1
H2O PUMP: P1202A
5 1 33300.0 1 13.0 0.00 0.00 1
H2O PUMP: P1202B
5 1 33300.0 1 13.0 0.00 0.00 1
INSTRUMENT/CONTROLS
1 1 15150.0 1 6.0 0.00 0.00 1
BFW TREATMENT
1 1 100000.0 1 16.0 0.00 0.00 1
STEAM TURBINE/GENERA...................[20]
100.0 1.0 8 4 0.00
-1 0 0.0
-1 1 0.0
1 2 0.0
1 2 0.0
VACUUM: P804A
3 1 14847.0 1 5.0 0.00 0.00 1
VACUUM: P804B
3 1 14847.0 1 5.0 0.00 0.00 1
HOTWELL: P801A
4 1 26282.0 1 29.0 0.00 0.00 1
HOTWELL: P801B
4 1 26282.0 1 29.0 0.00 0.00 1
SURF CONDENSER: E801
2 1 17550.0 1 23.0 0.00 0.00 1
CONTROLS MKV
1 1 35300.0 1 9.0 0.00 0.00 1
STEAM TURBINE:TG801
1 1 11800.0 1 30.0 0.00 0.00 1
GENERATOR
1 1 15263.0 1 44.0 0.00 0.00 1
STEAM BYPASS DERA......................[21]
53.0 1.0 1 0 0.00
REDUCED CAPACITY STATE
0 1 99999999.0 1 0.01 0.00 0.00 1
COOLING TOWER..........................[22]
100.0 1.0 8 3 0.00
-1 0 0.0
-1 1 0.0
-2 1 0.0
FILL: CT1201 (1 of 3)
2 1 175200.0 1 192.0 0.00 0.00 1
COOL TOWER FANS (1 of 3)
2 1 271182.0 1 30.0 0.00 0.00 1
COOL H2O: P1209A
3 1 28283.0 1 21.0 0.00 0.00 1
COOL H2O: P1209B
3 1 28283.0 1 21.0 0.00 0.00 1
COOL H2O: P1209C
3 1 28283.0 1 21.0 0.00 0.00 1
CT CONTROLS
1 1 15150.0 1 6.0 0.00 0.00 1
CT MAKEUP PUMP: P1201
1 1 18479.0 1 24.0 0.00 0.00 1
CIRC H2O TREATMENT
1 1 5801.0 1 3.0 0.00 0.00 1
CT1201 DERATING........................[23]
90.0 1.0 1 0 0.00
REDUCED CAPACITY STATE
0 1 99999999.0 1 0.01 0.00 0.00 1
INST/PLANT AIR.........................[24]
100.0 1.0 6 3 0.00
-1 0 0.0
1 1 0.0
1 1 0.0
COMPRESSOR: C1201A
2 1 284091.0 1 6.0 0.00 0.00 1
COMPRESSOR: C1201B
2 1 284091.0 1 6.0 0.00 0.00 1
AIR DRYER: DR1201A
3 1 1923077.0 1 3.0 0.00 0.00 1
AIR DRYER: DR1201B
3 1 1923077.0 1 3.0 0.00 0.00 1
RECEIVER: D1207
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1 1 1923077.0 1 3.0 0.00 0.00 1
CONTROLS
1 1 15150.0 1 6.0 0.00 0.00 1
ELECTRICAL SYSTEM......................[25]
100.0 1.0 15 6 0.00
-1 0 0.0
-2 1 0.0
-2 1 0.0
-1 3 0.0
-1 3 0.0
-2 1 0.0
TR 803
2 1 2920000.0 1 174.0 0.00 0.00 1
ATS
2 1 1436066.0 1 4.0 0.00 0.00 1
TR 804
2 1 2920000.0 1 174.0 0.00 0.00 1
BD 803/804
2 1 1429038.0 1 53.0 0.00 0.00 1
ATS
3 1 1436066.0 1 4.0 0.00 0.00 1
TR 801
4 1 673846.0 1 174.0 0.00 0.00 1
TR 802
4 1 2920000.0 1 174.0 0.00 0.00 1
BD 801/802
4 1 1429038.0 1 53.0 0.00 0.00 1
BD 701/702
5 1 1429038.0 1 53.0 0.00 0.00 1
TR 702
5 1 2920000.0 1 174.0 0.00 0.00 1
TR 701
5 1 673846.0 1 174.0 0.00 0.00 1
BD 805/806
6 1 1429038.0 1 53.0 0.00 0.00 1
TR 806
6 1 2920000.0 1 174.0 0.00 0.00 1
ATS
6 1 1436066.0 1 4.0 0.00 0.00 1
TR 805
6 1 2920000.0 1 174.0 0.00 0.00 1
PLANT CONTROLS..........................[26]
100.0 1.0 1 0 0.00
DCS
0 1 4431.0 1 3.0 0.00 0.00 1
WASTE WATER TREATMENT..................[27]
100.0 1.0 1 0 0.00
WASTE H2O TREATMENT
0 1 876000.0 1 48.0 48.00 0.00 1
CATASTROPHIC EVENTS....................[28]
100.0 1.0 1 0 0.00
FIRE/EXPLOSION
0 1 876000.0 1 336.00 0.00 0.00 1
NATGAS OPER MODE.......................[29]
92.5 1.0 1 0 0.00
REDUCED CAPACITY STATE
0 1 99999999.0 1 0.01 0.00 0.00 1
HOT RESTART............................[30]
100.0 1.0 25 4 0.0
-1 0 0.0
0 1 0.0
1 2 0.0
-2 2 0.0
HR CRUSHER: SR102
1 1 8760.0 1 11.4 0.00 0.00 1
HR COAL BIN: BN105
1 1 9495.0 1 11.4 0.00 0.00 1
HR LIME BIN: BN107
1 1 9495.0 1 11.4 0.00 0.00 1
HR SURGE BIN: BN301
1 1 6410.0 1 11.4 0.00 0.00 1
HR FEED HOPPER: BN303
1 1 9320.0 1 11.4 0.00 0.00 1
HR FILTER: F302
1 1 7620.0 1 11.4 0.00 0.00 1
HR H.P. PHOS: P1211A
4 1 8652.0 1 11.4 0.00 0.00 1
HR H.P. PHOS: P1211B
4 1 8652.0 1 11.4 0.00 0.00 1
HR H.P. PHOS: P1211C

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4 1 8652.0 1 11.4 0.00 0.00 1
HR FINES FEED: FD401
1 1 1610.0 1 11.4 0.00 0.00 1
HR FEED HOPPER: BN604
1 1 8224.0 1 11.4 0.00 0.00 1
HR REC HOPPER: BN610
1 1 6482.0 1 11.4 0.00 0.00 1
HR FILTER: F610
1 1 2000.0 1 11.4 0.00 0.00 1
HR LIME HOPPER: BN505
1 1 8423.0 1 11.4 0.00 0.00 1
HR FINES FEEDER: FD503
1 1 1610.0 1 11.4 0.00 0.00 1
HR FINES BIN: BN608
1 1 7920.0 1 11.4 0.00 0.00 1
HR FINES CHUTE: BN608A
1 1 6482.0 1 11.4 0.00 0.00 1
HR WASTE SILO: BN1101
1 1 9495.0 1 11.4 0.00 0.00 1
HR COMPRESSOR: C902
1 1 6000.0 1 11.4 0.00 0.00 1
HR GT ACCESS/AUXILIAR
1 1 6296.0 1 11.4 0.00 0.00 1
HR H.P. PHOS: P1211D
3 1 8652.0 1 11.4 0.00 0.00 1
HR H.P. PHOS: P1211C
3 1 8652.0 1 11.4 0.00 0.00 1
HR CIRC H2O TREATMENT
1 1 5801.0 1 11.4 0.00 0.00 1
HR DCS
1 1 4431.0 1 11.4 0.00 0.00 1
HR BALANCE
1 1 207.0 1 11.4 0.00 0.00 1
HOT RESTART DERATING...................[31]
77.0 1.0 1 0 0.00
REDUCED CAPACITY STATE
0 1 99999999.0 1 0.01 0.00 0.00 1
INTERMEDIATE RESTART...................[32]
100.0 1.0 10 1 0.0
-1 0 0.0
IR COMPRESSOR: C301
1 1 6000.0 1 42.0 0.00 0.00 1
IR HRSG DRUM: D602
1 1 8760.0 1 42.0 0.00 0.00 1
IR HRSG: SG602
1 1 8760.0 1 42.0 0.00 0.00 1
IR COLL HOPPER: BN501
1 1 8760.0 1 42.0 0.00 0.00 1
IR FEED HOPPER: BN508
1 1 9320.0 1 42.0 0.00 0.00 1
IR SOLIDS EDUCTOR
1 1 8760.0 1 42.0 0.00 0.00 1
IR COLL HOPPER: BN503
1 1 8760.0 1 42.0 0.00 0.00 1
IR FEED HOPPER: BN507
1 1 9320.0 1 42.0 0.00 0.00 1
IR SULF SOL BIN: BN607
1 1 7920.0 1 42.0 0.00 0.00 1
IR BALANCE
1 1 1017.0 1 42.0 0.00 0.00 1
INTERMEDIATE RESTART DERATING..........[33]
72.0 1.0 1 0 0.00
REDUCED CAPACITY STATE
0 1 99999999.0 1 0.01 0.00 0.00 1
COLD RESTART...........................[34]
100.0 1.0 4 1 0.00
-1 0 0.0
CR SULF REACTOR: R602
1 1 1700.0 1 142.0 0.00 0.00 1
CR COMBUSTOR: H602
1 1 5205.0 1 142.0 0.00 0.00 1
CR BAG FILTER: F602
1 1 8760.0 1 142.0 0.00 0.00 1
CR BALANCE
1 1 1105.0 1 142.0 0.00 0.00 1
COLD RESTART DERATING..................[35]
71.0 1.0 1 0 0.00
REDUCED CAPACITY STATE
0 1 99999999.0 1 0.01 0.00 0.00 1
11
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Nest1- 36
3 2
2 1
3 1
Nest2- 37
4 13
1 1
36 1
4 1
5 1
6 1
7 1
8 1
9 1
10 1
11 1
12 1
13 1
14 1
Nest3- 38
3 2
29 1
37 1
Nest4- 39
3 2
15 1
16 1
Nest5- 40
3 2
20 1
21 1
Nest6- 41
3 2
22 1
23 1
Nest7- 42
3 2
30 1
31 1
Nest8- 43
3 2
32 1
33 1
Nest9- 44
3 2
34 1
35 1
Nest10- 45
4 14
39 1
17 1
18 1
19 1
40 1
41 1
24 1
25 1
26 1
27 1
28 1
42 1
43 1
44 1
Nest11- 46
4 2
38 1
45 1
0
0
0

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****************** RUN  1 ******************
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BASELINE RUN

FAULT TREE EVALUATION

SUBSYSTEM	MEAN DOWNTIME (HOURS)	MEAN TIME BETWEEN FAILURES (HOURS)	AVAILABILITY
1 COAL RECEI	.01	100000000.00	1.0000
2 COAL CRUSH	22.74	7688.97	.9971
3 COAL C/T D	.01	100000000.00	1.0000
4 OXIDANT CO	16.64	4560.93	.9964
5 GASIFIER/F	30.20	782.04	.9628
6 HRSG: GASI	37.61	3232.93	.9885
7 GAS TREAT/	16.61	4914.92	.9966
8 DESULFURIZ	15.33	569.24	.9738
9 SULFATOR/A	25.99	566.88	.9562
10 FINES COMB	10.44	713.01	.9856
11 DESULF SOL	10.01	1400.29	.9929
12 PARTICULAT	46.65	5803.89	.9920
13 SOLID WAST	19.93	193238.30	.9999
14 RECYCLE GA	24.01	2398.50	.9901
15 EVAPORATIV	35.00	33200.00	.9989
16 EVAP COOLE	.01	100000000.00	1.0000
17 GAS TURBIN	39.97	2006.65	.9805
18 HRSG POWER	57.53	6236.72	.9909
19 BFW MAKEUP	7.02	10096.03	.9993
20 STEAM TURB	29.73	4242.66	.9930
21 STEAM BYPA	.01	100000000.00	1.0000
22 COOLING TO	11.34	3310.61	.9966
23 CT1201 DER	.01	100000000.00	1.0000
24 INST/PLANT	5.98	15031.55	.9996
25 ELECTRICAL	.01	100000000.00	1.0000
26 PLANT CONT	3.00	4431.00	.9993
27 WASTE WATE	48.00	2381215.00	1.0000
28 CATASTROPH	336.00	876000.00	.9996
29 NATGAS OPE	.01	100000000.00	1.0000
30 HOT RESTAR	11.80	113.67	.9060
31 HOT RESTAR	.01	100000000.00	1.0000
32 INTERMEDIA	43.37	485.06	.9179
33 INTERMEDIA	.01	100000000.00	1.0000
34 COLD RESTA	153.65	555.71	.7834
35 COLD RESTA	.01	100000000.00	1.0000

STATE DEFINITIONS WITH CORRESPONDING OUTPUT CAPABILITIES

SUBSYSTEM	CURTAIL-MENT LEVEL	STATE AVAILABILITY (PERCENTAGE)	STATE OUTPUT CAPACITY (PERCENTAGE)
36 Nest1- 36			
	0	99.705120	100.00
	1	.294876	97.00
	2	.000000	.00
37 Nest2- 37			
	0	84.319810	100.00
	1	.249374	97.00
	2	15.430820	.00
38 Nest3- 38			
	0	84.569180	100.00

	1	.000000	97.00
	2	15.430800	92.50
	3	.000016	.00
39 Nest4- 39			
	0	99.894690	100.00
	1	.105309	96.00
	2	.000000	.00
40 Nest5- 40			
	0	99.304060	100.00
	1	.695934	53.00
	2	.000001	.00
41 Nest6- 41			
	0	99.658730	100.00
	1	.341270	90.00
	2	.000000	.00
42 Nest7- 42			
	0	90.598080	100.00
	1	9.401909	77.00
	2	.000010	.00
43 Nest8- 43			
	0	91.792450	100.00
	1	8.207538	72.00
	2	.000008	.00
44 Nest9- 44			
	0	78.339740	100.00
	1	21.660230	71.00
	2	.000022	.00
45 Nest10- 45			
	0	62.435990	100.00
	1	.065820	96.00
	2	.214030	90.00
	3	6.508400	77.00
	4	6.189622	72.00
	5	20.851250	71.00
	6	.674637	53.00
	7	3.060236	.00
46 Nest11- 46			
	0	52.801610	100.00
	1	.000000	97.00
	2	.055664	96.00
	3	9.644531	92.50
	4	.214030	90.00
	5	6.508399	77.00
	6	6.189621	72.00
	7	20.851250	71.00
	8	.674637	53.00
	9	3.060252	.00

PLANT STATE	OUTPUT STATE PROBABILITY	OUTPUT CAPABILITY	DAYS/ YEAR	POWER (MW) OUTPUT
1	52.80%	100.00%	188.17	100.00
2	.00%	97.00%	.00	97.00
3	.06%	96.00%	.20	96.00
4	9.64%	92.50%	34.37	92.50
5	.21%	90.00%	.76	90.00
6	6.51%	77.00%	23.19	77.00
7	6.19%	72.00%	22.06	72.00

8	20.85%	71.00%	74.31	71.00
9	.67%	53.00%	2.40	53.00
10	3.06%	.00%	10.91	.00

PLANT RAM MEASURES

FORCED OUTAGE RATE	EQUIVALENT FORCED OUTAGE RATE	EQUIVALENT AVAILABILITY FACTOR	AVAILABILITY FACTOR
3.06%	13.40%	84.55%	94.65%

UNIT-LEVEL R&M VALUES

UNIT MEAN TIME BETWEEN FULL FORCED OUTAGES (HOURS)	MEAN UNIT FULL FORCED OUTAGE DURATION (HOURS)
902.4	28.5

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******************* RUN  1 *******************
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COMPONENT RANKING FOR CRITICALITY

SUB. NO.	COMP. NO.	RANKING FACTOR	SUBSYSTEM	COMPONENT	HOUR EQUIV	OUTPUT PCT.
34	4	2.2994	COLD RESTA	CR BALANCE	196.7	20.8
34	1	1.4946	COLD RESTA	CR SULF REACTOR: R60	127.8	13.5
30	25	.7533	HOT RESTAR	HR BALANCE	64.4	6.8
32	10	.7078	INTERMEDIA	IR BALANCE	60.5	6.4
17	3	.6597	GAS TURBIN	GT COMPRESSOR	56.4	6.0
18	9	.6006	HRSG POWER	HRSG: SG801	51.4	5.4
34	2	.4882	COLD RESTA	CR COMBUSTOR: H602	41.8	4.4
17	4	.4016	GAS TURBIN	TURBINE/BEARINGS	34.3	3.6
34	3	.2900	COLD RESTA	CR BAG FILTER: F602	24.8	2.6
17	1	.2246	GAS TURBIN	GT GENERATOR	19.2	2.0
17	9	.1519	GAS TURBIN	GT ELECTRICAL	13.0	1.4
9	10	.1398	SULFATOR/A	SULF REACTOR: R602	12.0	1.3
17	10	.1238	GAS TURBIN	GT ACCESS/AUXILIAR	10.6	1.1
32	1	.1199	INTERMEDIA	IR COMPRESSOR: C301	10.3	1.1
20	8	.1015	STEAM TURB	GENERATOR	8.7	.9
30	10	.0968	HOT RESTAR	HR FINES FEED: FD401	8.3	.9
30	15	.0968	HOT RESTAR	HR FINES FEEDER: FD5	8.3	.9
32	9	.0909	INTERMEDIA	IR SULF SOL BIN: BN6	7.8	.8
20	7	.0895	STEAM TURB	STEAM TURBINE:TG801	7.7	.8
32	2	.0822	INTERMEDIA	IR HRSG DRUM: D602	7.0	.7
32	3	.0822	INTERMEDIA	IR HRSG: SG602	7.0	.7
32	4	.0822	INTERMEDIA	IR COLL HOPPER: BN50	7.0	.7
32	6	.0822	INTERMEDIA	IR SOLIDS EDUCTOR	7.0	.7
32	7	.0822	INTERMEDIA	IR COLL HOPPER: BN50	7.0	.7
30	13	.0780	HOT RESTAR	HR FILTER: F610	6.7	.7
32	5	.0772	INTERMEDIA	IR FEED HOPPER: BN50	6.6	.7
32	8	.0772	INTERMEDIA	IR FEED HOPPER: BN50	6.6	.7
17	5	.0687	GAS TURBIN	GT COMBUSTOR	5.9	.6
26	1	.0585	PLANT CONT	DCS	5.0	.5
18	8	.0507	HRSG POWER	L.P. DRUM: D802	4.3	.5
18	7	.0506	HRSG POWER	H.P. DRUM: D801	4.3	.5
17	7	.0498	GAS TURBIN	GT EXHAUST	4.3	.4
20	5	.0462	STEAM TURB	SURF CONDENSER: E801	3.9	.4
5	16	.0418	GASIFIER/F	GASIF REFRACTORY: R3	3.6	.4
5	15	.0369	GASIFIER/F	ANNULUS REFRACTROY	3.2	.3
18	11	.0362	HRSG POWER	DEAERATOR: DH801	3.1	.3
30	24	.0352	HOT RESTAR	HR DCS	3.0	.3
19	13	.0343	BFW MAKEUP	INSTRUMENT/CONTROLS	2.9	.3
24	6	.0343	INST/PLANT	CONTROLS	2.9	.3
28	1	.0331	CATASTROPH	FIRE/EXPLOSION	2.8	.3
10	6	.0312	FINES COMB	COMBUSTOR: H602 (sys	2.7	.3
18	14	.0301	HRSG POWER	HRSG CONTROLS	2.6	.3
30	23	.0269	HOT RESTAR	HR CIRC H2O TREATMEN	2.3	.2
30	19	.0260	HOT RESTAR	HR COMPRESSOR: C902	2.2	.2
30	20	.0248	HOT RESTAR	HR GT ACCESS/AUXILIA	2.1	.2
30	4	.0243	HOT RESTAR	HR SURGE BIN: BN301	2.1	.2
12	2	.0241	PARTICULAT	HOT GAS FILTER ELEME	2.1	.2
30	12	.0241	HOT RESTAR	HR REC HOPPER: BN610	2.1	.2
30	17	.0241	HOT RESTAR	HR FINES CHUTE: BN60	2.1	.2
17	2	.0220	GAS TURBIN	GT INLET	1.9	.2
6	2	.0217	HRSG: GASI	HRSG: SG602	1.9	.2
6	7	.0217	HRSG: GASI	HRSG DRUM: D602	1.9	.2
30	6	.0205	HOT RESTAR	HR FILTER: F302	1.8	.2
5	6	.0198	GASIFIER/F	COMPRESSOR: C301	1.7	.2
14	4	.0198	RECYCLE GA	COMPRESSOR: C902	1.7	.2
30	16	.0197	HOT RESTAR	HR FINES BIN: BN608	1.7	.2
30	11	.0190	HOT RESTAR	HR FEED HOPPER: BN60	1.6	.2
30	14	.0185	HOT RESTAR	HR LIME HOPPER: BN50	1.6	.2
30	1	.0178	HOT RESTAR	HR CRUSHER: SR102	1.5	.2
30	5	.0167	HOT RESTAR	HR FEED HOPPER: BN30	1.4	.2
30	2	.0164	HOT RESTAR	HR COAL BIN: BN105	1.4	.1
30	3	.0164	HOT RESTAR	HR LIME BIN: BN107	1.4	.1
30	18	.0164	HOT RESTAR	HR WASTE SILO: BN110	1.4	.1
5	13	.0157	GASIFIER/F	GASIFIER FEED TUBE	1.3	.1

19	14	.0138	BFW MAKEUP BFW TREATMENT	1.2	.1
8	4	.0136	DESULFURIZ REFRACTORY CYCLONE:	1.2	.1
8	5	.0136	DESULFURIZ REFRACTORY CYCLONE:	1.2	.1
8	6	.0136	DESULFURIZ REFRACTORY CYCLONE:	1.2	.1
8	13	.0136	DESULFURIZ REGEN REFRACTORY: R6	1.2	.1
8	12	.0136	DESULFURIZ DESULF REFRACTORY: R	1.2	.1
11	9	.0109	DESULF SOL BAG FILTER: F602	.9	.1
10	4	.0098	FINES COMB FINES FEEDER: FD503	.8	.1
8	3	.0098	DESULFURIZ FINES FEED: FD401	.8	.1
18	10	.0097	HRSG POWER ATTEMPERATOR: DS801	.8	.1
18	12	.0097	HRSG POWER M.P. DESUPHTR: DS802	.8	.1
18	13	.0097	HRSG POWER PEG DESUPHTR: DS803	.8	.1
5	12	.0090	GASIFIER/F CYCLONE REFRACTORY:	.8	.1
20	6	.0090	STEAM TURB CONTROLS MKV	.8	.1
14	3	.0089	RECYCLE GA COMPRESSOR: C901	.8	.1
22	7	.0072	COOLING TO CT MAKEUP PUMP: P120	.6	.1
8	14	.0068	DESULFURIZ REGEN COOLER: E607	.6	.1
8	16	.0068	DESULFURIZ PIPE REFRACTORY	.6	.1
5	20	.0065	GASIFIER/F GASIFIER VESSEL	.6	.1
22	1	.0061	COOLING TO FILL: CT1201 (1 of 3	.5	.1
4	9	.0060	OXIDANT CO BST COMPRESSOR: C201	.5	.1
9	9	.0060	SULFATOR/A VENT FILTER: F502	.5	.1
10	5	.0060	FINES COMB VENT FILTER: F503	.5	.1
19	6	.0059	BFW MAKEUP MIX BED: D1211	.5	.1
17	8	.0057	GAS TURBIN GT CONTROLS (MKIV)	.5	.1
9	11	.0054	SULFATOR/A SULF CYCLONE: S601	.5	.0
7	2	.0054	GAS TREAT/ GAS TRIMMER: E403	.5	.0
7	1	.0054	GAS TREAT/ GAS COOLER: E401	.5	.0
11	3	.0049	DESULF SOL FINES CHUTE: BN 608A	.4	.0
12	1	.0045	PARTICULAT HOT GAS FILTER REFRA	.4	.0
9	15	.0045	SULFATOR/A PIPE REFRACTORY	.4	.0
17	6	.0043	GAS TURBIN GT FUEL CONTROLS	.4	.0
14	7	.0043	RECYCLE GA TRIM COOLER: E901	.4	.0
5	10	.0034	GASIFIER/F FEED HOPPER: BN303	.3	.0
9	5	.0034	SULFATOR/A FEED HOPPER: BN508	.3	.0
10	1	.0034	FINES COMB FEED HOPPER: BN507	.3	.0
9	12	.0032	SULFATOR/A SULF COMPRESS: C601	.3	.0
22	8	.0029	COOLING TO CIRC H2O TREATMENT	.2	.0
19	5	.0026	BFW MAKEUP AN/CAT: D1204/03	.2	.0
8	2	.0026	DESULFURIZ REGEN HEATER: H608S2	.2	.0
8	1	.0026	DESULFURIZ REGEN HEATER: H608S1	.2	.0
19	7	.0026	BFW MAKEUP CAUS HEATER: E1201	.2	.0
5	9	.0025	GASIFIER/F PRESS HOPPER: BN302	.2	.0
9	7	.0025	SULFATOR/A DEPRES HOPPER: BN502	.2	.0
10	3	.0025	FINES COMB DEPRES HOPPER: BN504	.2	.0
9	13	.0025	SULFATOR/A SOLIDS COOLER: E605	.2	.0
11	6	.0024	DESULF SOL SCR CONVEYOR: CR602	.2	.0
8	8	.0024	DESULFURIZ FEED HOPPER: BN604	.2	.0
15	1	.0022	EVAPORATIV EVAPORATIVE COOLER	.2	.0
22	6	.0022	COOLING TO CT CONTROLS	.2	.0
11	2	.0020	DESULF SOL FINES BIN: BN608	.2	.0
11	1	.0020	DESULF SOL SULF SOL BIN: BN607	.2	.0
5	19	.0020	GASIFIER/F CONVEYOR: CR110	.2	.0
9	1	.0019	SULFATOR/A LIME HOPPER: BN505	.2	.0
14	5	.0019	RECYCLE GA GAS COOLER: E402S1	.2	.0
14	6	.0019	RECYCLE GA GAS COOLER: E402S2	.2	.0
5	17	.0018	GASIFIER/F LIME FEEDER: FD108	.2	.0
5	5	.0018	GASIFIER/F COAL FEEDER: FD301	.2	.0
9	4	.0018	SULFATOR/A ASH FEEDER: FD502	.2	.0
9	17	.0018	SULFATOR/A SOLIDS EDUCTOR	.2	.0
10	8	.0018	FINES COMB BLOWER: C602	.2	.0
5	3	.0018	GASIFIER/F FILTER: F301	.2	.0
5	18	.0018	GASIFIER/F COAL FEEDER: FD106	.2	.0
27	1	.0017	WASTE WATE WASTE H2O TREATMENT	.1	.0
6	6	.0016	HRSG: GASI HRSG GASIF CONTROLS	.1	.0
4	1	.0016	OXIDANT CO EXTRACT AIR CONTROLS	.1	.0
8	18	.0015	DESULFURIZ BLOWER: C610	.1	.0
11	7	.0015	DESULF SOL EXPANSION JOINTS	.1	.0
11	11	.0015	DESULF SOL BELLOWS	.1	.0
5	8	.0012	GASIFIER/F SURGE BIN: BN301	.1	.0
8	9	.0012	DESULFURIZ VENT FILTER: F605	.1	.0
8	17	.0012	DESULFURIZ PIPING, VALVE SOLIDS	.1	.0
9	2	.0012	SULFATOR/A VENT FILTER: F504	.1	.0
9	8	.0012	SULFATOR/A GAS ASH FEED: FD302	.1	.0
5	7	.0011	GASIFIER/F AIR RECEIVER: D301	.1	.0
11	5	.0011	DESULF SOL COLL HOPPER: BN601	.1	.0
5	4	.0010	GASIFIER/F FILTER: F302	.1	.0
9	14	.0010	SULFATOR/A I&C SYSTEM CONTROLS	.1	.0
9	19	.0010	SULFATOR/A I&C CONTROL VALVES	.1	.0
10	9	.0010	FINES COMB I&C CONTROL VALVES	.1	.0

8	19	.0010	DESULFURIZ FILTER: F610	.1	.0
6	1	.0009	HRSG: GASI GASIF ST DRUM: SG401	.1	.0
7	5	.0009	GAS TREAT/ VALVE TV0071	.1	.0
7	6	.0009	GAS TREAT/ VALVE PDVO70	.1	.0
9	6	.0009	SULFATOR/A COLL HOPPER: BN501	.1	.0
10	2	.0009	FINES COMB COLL HOPPER: BN503	.1	.0
4	11	.0009	OXIDANT CO KO DRUM: D201	.1	.0
4	4	.0009	OXIDANT CO AIR PRECOOL: E203S2	.1	.0
4	6	.0009	OXIDANT CO AIR RECUPER: E201S2	.1	.0
4	7	.0009	OXIDANT CO TRIM COOLER: E202	.1	.0
4	10	.0009	OXIDANT CO AIR COOLER: E204	.1	.0
11	4	.0009	DESULF SOL SCREW COOLER: E602	.1	.0
12	5	.0009	PARTICULAT PART COOLER: E502	.1	.0
12	6	.0009	PARTICULAT SCREW COOLER: E501	.1	.0
19	8	.0009	BFW MAKEUP DECARBONATOR: T1201	.1	.0
4	3	.0008	OXIDANT CO AIR PRECOOL: E203S1	.1	.0
4	5	.0008	OXIDANT CO AIR RECUPER: E201S1	.1	.0
11	10	.0008	DESULF SOL I&C TRANSMIT CONTROL	.1	.0
12	7	.0008	PARTICULAT PART REMOV CONTROLS	.1	.0
14	2	.0008	RECYCLE GA RECEIVER: D901	.1	.0
14	9	.0008	RECYCLE GA I&C SYSTEM CONTROLS	.1	.0
5	11	.0008	GASIFIER/F I&C GASIFIER CONTROL	.1	.0
8	15	.0008	DESULFURIZ I&C CONTROLS	.1	.0
9	3	.0008	SULFATOR/A I&C SULFATOR CONTROL	.1	.0
10	7	.0008	FINES COMB I&C SYSTEM CONTROLS	.1	.0
14	1	.0008	RECYCLE GA KO DRUM: D902	.1	.0
4	8	.0007	OXIDANT CO CONTROL VALVES	.1	.0
12	8	.0006	PARTICULAT HTF TANK: D501	.1	.0
22	2	.0006	COOLING TO COOL TOWER FANS (1 o	.1	.0
9	18	.0006	SULFATOR/A FEEDLINE ELBOWS	.1	.0
5	14	.0005	GASIFIER/F I&C CONTROL VALVES	.0	.0
7	4	.0005	GAS TREAT/ I&C CONTROLS	.0	.0
5	21	.0005	GASIFIER/F SOLIDS FEED LINE	.0	.0
5	22	.0005	GASIFIER/F VALVE, SOLIDS ISOLAT	.0	.0
14	8	.0005	RECYCLE GA VALVES, PULSE GAS	.0	.0
8	7	.0005	DESULFURIZ STORE HOPPER: BN603	.0	.0
8	11	.0004	DESULFURIZ DRUM UNLD: PG602	.0	.0
11	8	.0004	DESULF SOL AIR DRYER: DR601	.0	.0
9	16	.0004	SULFATOR/A VALVES, SOLIDS ISOLA	.0	.0
13	2	.0003	SOLID WAST EXHAUST FAN: B1102	.0	.0
7	3	.0002	GAS TREAT/ HYD CONTROLS: HC100	.0	.0
10	10	.0002	FINES COMB PIPING FEEDLINE ELBO	.0	.0
24	5	.0001	INST/PLANT RECEIVER: D1207	.0	.0
4	2	.0001	OXIDANT CO COMPRESS BLEED VALVE	.0	.0
24	1	.0001	INST/PLANT COMPRESSOR: C1201A	.0	.0
24	2	.0001	INST/PLANT COMPRESSOR: C1201B	.0	.0
18	1	.0001	HRSG POWER H.P. PHOS: P1211D	.0	.0
18	2	.0001	HRSG POWER H.P. PHOS: P1211C	.0	.0
13	8	.0001	SOLID WAST DISCHARGER: BV1101	.0	.0
13	1	.0001	SOLID WAST SLIDE GATE: XV1101	.0	.0
20	3	.0000	STEAM TURB HOTWELL: P801A	.0	.0
20	4	.0000	STEAM TURB HOTWELL: P801B	.0	.0
30	7	.0000	HOT RESTAR HR H.P. PHOS: P1211A	.0	.0
30	8	.0000	HOT RESTAR HR H.P. PHOS: P1211B	.0	.0
30	9	.0000	HOT RESTAR HR H.P. PHOS: P1211C	.0	.0
20	1	.0000	STEAM TURB VACUUM: P804A	.0	.0
20	2	.0000	STEAM TURB VACUUM: P804B	.0	.0
30	21	.0000	HOT RESTAR HR H.P. PHOS: P1211D	.0	.0
30	22	.0000	HOT RESTAR HR H.P. PHOS: P1211C	.0	.0
2	3	.0000	COAL CRUSH VIBR FEEDER: FD114	.0	.0
2	4	.0000	COAL CRUSH CONVEYOR: CR118	.0	.0
2	6	.0000	COAL CRUSH COL CONVEYOR: CR105	.0	.0
2	7	.0000	COAL CRUSH OVER CONVEYOR: CR114	.0	.0
2	8	.0000	COAL CRUSH SIZE CONVEYOR: CR115	.0	.0
2	9	.0000	COAL CRUSH OVERSIZE FEED: FD117	.0	.0
2	11	.0000	COAL CRUSH SCREEN: SE104	.0	.0
2	15	.0000	COAL CRUSH INSTRUMENT/CONTROLS	.0	.0
5	1	.0000	GASIFIER/F STEAM TURBINE PCV	.0	.0
5	2	.0000	GASIFIER/F HRSG PCV	.0	.0
12	3	.0000	PARTICULAT HTF PUMP: P501A	.0	.0
12	4	.0000	PARTICULAT HTF PUMP: P501B	.0	.0
22	3	.0000	COOLING TO COOL H2O: P1209A	.0	.0
22	4	.0000	COOLING TO COOL H2O: P1209B	.0	.0
22	5	.0000	COOLING TO COOL H2O: P1209C	.0	.0
1	1	.0000	COAL RECEI INSTRUMENT/CONTROLS	.0	.0
1	2	.0000	COAL RECEI CONVEYOR: CR102	.0	.0
1	3	.0000	COAL RECEI COAL BIN: BN101A	.0	.0
1	4	.0000	COAL RECEI COAL BIN: 101B	.0	.0
1	5	.0000	COAL RECEI COAL FEEDER: FD101A	.0	.0
1	6	.0000	COAL RECEI COAL FEEDER: FD101B	.0	.0

1	7	.0000	COAL RECEI RECL BLOWER: B116	.0	.0
1	8	.0000	COAL RECEI STORE DOME: X100	.0	.0
2	1	.0000	COAL CRUSH EMER HOPPER: BN108	.0	.0
2	2	.0000	COAL CRUSH EMER FEEDER:	.0	.0
2	5	.0000	COAL CRUSH RECLAIMER: RL101	.0	.0
2	10	.0000	COAL CRUSH DIVERTER: DV105	.0	.0
2	12	.0000	COAL CRUSH CRUSHER: SR102	.0	.0
2	13	.0000	COAL CRUSH LIME BIN: BN107	.0	.0
2	14	.0000	COAL CRUSH COAL BIN: BN105	.0	.0
3	1	.0000	COAL C/T D REDUCED CAPACITY STA	.0	.0
6	3	.0000	HRSG: GASI H.P. PHOS: P1211A	.0	.0
6	4	.0000	HRSG: GASI H.P. PHOS: P1211B	.0	.0
6	5	.0000	HRSG: GASI SPARE PHOS: P1211C	.0	.0
8	10	.0000	DESULFURIZ REC HOPPER: BN610	.0	.0
13	3	.0000	SOLID WAST LDOUT FILTER: F1102	.0	.0
13	4	.0000	SOLID WAST LOAD CHUTE: CH1101	.0	.0
13	5	.0000	SOLID WAST CHUTE VIBR: BV1102	.0	.0
13	6	.0000	SOLID WAST WASTE SILO: BN1101	.0	.0
13	7	.0000	SOLID WAST VENT FILTER: F1101	.0	.0
16	1	.0000	EVAP COOLE EVAP COOLER DERATING	.0	.0
18	3	.0000	HRSG POWER L.P. BFW: P802A	.0	.0
18	4	.0000	HRSG POWER L.P. BFW: P802B	.0	.0
18	5	.0000	HRSG POWER H.P. BFW: P803A	.0	.0
18	6	.0000	HRSG POWER H.P. BFW: P803B	.0	.0
19	1	.0000	BFW MAKEUP BOOST PUMP: P1217A/B	.0	.0
19	2	.0000	BFW MAKEUP DEMIN PUMP: P1208A/B	.0	.0
19	3	.0000	BFW MAKEUP REGEN PUMP: P1221A/B	.0	.0
19	4	.0000	BFW MAKEUP ACID PUMP: P1203A/B	.0	.0
19	9	.0000	BFW MAKEUP TANK	.0	.0
19	10	.0000	BFW MAKEUP WELL	.0	.0
19	11	.0000	BFW MAKEUP H2O PUMP: P1202A	.0	.0
19	12	.0000	BFW MAKEUP H2O PUMP: P1202B	.0	.0
21	1	.0000	STEAM BYPA REDUCED CAPACITY STA	.0	.0
23	1	.0000	CT1201 DER REDUCED CAPACITY STA	.0	.0
24	3	.0000	INST/PLANT AIR DRYER: DR1201A	.0	.0
24	4	.0000	INST/PLANT AIR DRYER: DR1201B	.0	.0
25	1	.0000	ELECTRICAL TR 803	.0	.0
25	2	.0000	ELECTRICAL ATS	.0	.0
25	3	.0000	ELECTRICAL TR 804	.0	.0
25	4	.0000	ELECTRICAL BD 803/804	.0	.0
25	5	.0000	ELECTRICAL ATS	.0	.0
25	6	.0000	ELECTRICAL TR 801	.0	.0
25	7	.0000	ELECTRICAL TR 802	.0	.0
25	8	.0000	ELECTRICAL BD 801/802	.0	.0
25	9	.0000	ELECTRICAL BD 701/702	.0	.0
25	10	.0000	ELECTRICAL TR 702	.0	.0
25	11	.0000	ELECTRICAL TR 701	.0	.0
25	12	.0000	ELECTRICAL BD 805/806	.0	.0
25	13	.0000	ELECTRICAL TR 806	.0	.0
25	14	.0000	ELECTRICAL ATS	.0	.0
25	15	.0000	ELECTRICAL TR 805	.0	.0
29	1	.0000	NATGAS OPE REDUCED CAPACITY STA	.0	.0
31	1	.0000	HOT RESTAR REDUCED CAPACITY STA	.0	.0
33	1	.0000	INTERMEDIA REDUCED CAPACITY STA	.0	.0
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APPENDIX D

TECHNICAL BASELINE

This Appendix contains the Technical Baseline document, which includes the engineering descriptions and design parameters for the entire facility.

Sierra Pacific Power Company
Tracy 4 - Piñon Project
FW USA Contract No. 15-4140

January 9, 1996
Revision 2

TECHNICAL BASELINE

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1.0 INTRODUCTION

The technical baseline contained in this section of the management plan includes the engineering descriptions and design parameters for the entire facility.

The Piñon Pine Power Project is to be located at the Sierra Pacific Power Company's Tracy Station near Reno, Nevada. The plant will be designed to process 880 TPD of bituminous coal producing approximately 107 gross MWe of electric power.

The plant incorporates the KRW gasification technology which produces a low-Btu gas which is used as fuel in a combined cycle power plant which has been modified to accommodate the fuel gas produced by an air-blown KRW gasifier. The gasification system also includes hot gas removal of particulates and sulfur compounds from the fuel gas to produce a plant with exceptionally low atmospheric emissions. Desulfurization is accomplished by a combination of limestone injection into the KRW fluidized bed gasifier and by a transport reactor system. Particulate removal is accomplished by high efficiency cyclones and a barrier filter.

2.0 DESIGN CONSIDERATIONS

2.1 Location and Description of Site

The site selected for the Piñon Pine Power Project is the existing Tracy Power Plant located approximately 17 miles east of Reno, Nevada.

Tracy is a 724-acre site located in a rural portion of Storey County, Nevada, approximately 17 miles east of the Reno/Sparks area (population 250,000) and 15 miles west of the Town of Fernley (population 7,000) Nevada. U.S. Interstate 80 is immediately adjacent and provides easy access to the site. The site is capable of accommodating the gasification plant, power plant facilities and all support facilities, with minimal site work.

2.2 Area Geology

The proposed site is located in the Truckee River Canyon. Late during the Pleistocene Epoch, the Truckee River Canyon was occupied by Lake Lahontan, which covered an area extending approximately 40.2 km (25 miles) south from Pyramid Lake. As the lake receded, the Truckee River began to down-cut into the lake deposits and subsequently formed the present canyon.

Where the river eroded away the lake sediments, it deposited fluvial channel (beds of river materials) and overbank deposits in their place. As a result, near-surface sediments at the site are composed primarily of river deposits consisting of minor clays, silts, sands, gravelly sands, sandy gravels, and coarse gravels. Lake deposits of clay, silt, sand, gravel, and calcareous tufa (porous stone containing calcium) may occur beneath the site. The most recent deposits are relatively thin eolian (windblown) deposits of silt and fine sand that mantle (cover) portions of the surface.

The hills south of the site consist largely of olivine basalt (rock of volcanic origin containing a mineral silicate of magnesium and iron) and hornblende andesite (mineral consisting of silicate of calcium, magnesium, and iron in fine-grained volcanic rock) flows of the Pleistocene Kate Peak Formation, which provided much of the material that presently fills the canyon. The site itself is relatively level to very gently rolling terrain with moderate relief. The site elevation is highest toward the south and gently slopes to the north toward the Truckee River. Relief in the surrounding area varies from very low in some of the intermountain basins to quite high in the adjacent mountain ranges. The average elevation at the site is approximately 1,295 meters (4,250 feet). Typical elevations of the nearby basins are between 1,219 and 1,829 meters (4,000 and 6,000 feet); elevations at the tops of bordering mountain blocks range between 1,829 meters and 2,438 meters (6,000 and 8,000 feet). The major structural elements in the general region surrounding the site are the Pah Rah Range to the north; the Virginia Range to the south; the Walker Lane Fault Zone to the northeast; and the Olinghouse Fault Zone, which trends eastwest along the southern flanks of the Pah Rah Range.

The Tracy Power Station project site is located in the western part of the Great Basin Tectonic Province. The site is located about 40.2 km (25 miles) from the adjacent Sierra Nevada Tectonic Province. This location, in a transition zone between two tectonic provinces, is one of the most seismically active (Seismic Zone 4) and complex regions of the United States.

Based on seismicity and style of faulting, the western Great Basin has been divided into three subprovinces (*Selmmons, 1980*): (1) the transition between the Sierra Nevada Frontal Fault Zone and the Walker Lane Fault Zone: (2) the Walker Lane Fault Zone: and (3) the Great Basin Zone east of Walker Lane Fault Zone. The Walker Lane Fault Zone is a 32.2-km (20 mile) wide, northwest trending zone of mainly right-lateral faults that extend from near

Walker Lake northwest through Pyramid Lake and into the Modoc Plateau of California. North of Pyramid Lake, the faults tend to radiate more northward and the Walker Lane Fault Zone becomes wider and more diffuse overall. The Walker Lane faults south of Pyramid Lake are relatively quiet compared to the faults in the other sub provinces, although active faults are abundant in northeast California. The closest active fault to the site within the Walker Lane is the Pyramid Lake strand, which is approximately 22 km (15 miles) from the site. It has an estimated Maximum Credible Earthquake value of 7.5. (A maximum Credible Earthquake, MCE, is the most serious earthquake that can be hypothesized from known geologic characteristics.)

East of the Walker Lane Fault Zone, faults are generally north-south trending normal faults. This part of the Great Basin has had several historic earthquakes of magnitude 6.6 to 7.7, including the 1954 Rainbow Mountain Fairview Peak, and Dixie Valley earthquakes. Epicenters along the Dixie Valley-Fairview Peak area continue south across the Walker Lake Fault Zone and intersect the Sierra Nevada Frontal Fault Zone. Forty-four earthquakes of magnitude greater than 5.0 have been reported in the area between 1852 and 1992.

The Truckee-Verdi-Reno-Olinghouse Transverse Fault Zone is of particular concern because it passes near the proposed site and includes the Olinghouse Fault Zone. The active portion of the Olinghouse Fault Zone extends from 16 km (10 miles) east of Reno along the north side of the Truckee River Canyon, passes through Olinghouse Canyon, and abruptly arcs to the northeast to terminate against a fault of the Walker Lane Fault Zone for a total length of 23 km (14 miles). In 1869, a series of earthquakes with magnitudes up to 6.7 occurred along this fault producing surface rupture north, west, and east of Tracy. This fault is located approximately 1.6 km (1 mile) from the proposed site at its closest approach; it has an estimated Maximum Credible Earthquake value of 7.1.

The largest historical seismic events close to the project site are the 1852 event with a possible magnitude of 7.0 and the three December 1869 earthquakes with estimated magnitudes of between 5.5 and 6.7. The 1852 earthquake was located just south of Tracy Station; however, the precise location of the earthquake has not been determined because information is based solely on descriptions by members of the Paiute Indian Tribe who were camping south of Pyramid Lake near Wadsworth. The epicenters of the 1869 earthquakes were located on the Olinghouse Fault Zone 16 to 39 km (10 to 24 miles) east of Reno. This zone is where the surface rupture occurred and includes the closest approach of the fault to the site.

The extent of wetlands is sufficiently limited to the extreme northern portion of the property so that siting new facilities can be done to avoid permanent wetland disturbance. A temporary fence can be erected to restrict construction activities outside of the wetlands.

2.3 Environmental, Safety and Hazard Considerations

The Piñon Pine Power Project will comply with environmental, health, safety and socioeconomic (EHSS) statues and regulations. The probability of EHSS compliance is essentially assured. EHSS risks will be minimized. Health and safety plans, based on existing experience, are referenced. Adverse environmental impacts will be at acceptable levels, and socioeconomic impacts will be beneficial. Mitigation measures identified in the Final Environmental Impact Statement (EIS) have been incorporated into the Record of Decision.

The probability of EHSS compliance for the Piñon Pine Project is essentially assured because of the understanding of permit and regulatory requirements, and the adherence to safety regulations and codes. Please see Section 1.1.4 for permits required for project.

Construction and operation of the Piñon Pine Power Project will be undertaken in a safe manner and in compliance with the general requirements of the Occupational Health and Safety Act (OSHA) PL 91-596, Part 1926 for construction and Part 1910 for operating.

Hazardous wastes will be handled in full compliance with OSHA Standard 29 CFR Part 1910.1200. These requirements relate to the Hazard Communication/Right-to-Know Program.

Presently there are no specific OSHA requirements in Nevada for the protection of workers in gasification plants. Guidelines for workers health and safety at coal gasification facilities have been recommended by the National Institute of Occupational Safety and Health (NIOSH) in:

- "Recommended Health and Safety Guidelines for Coal Gasification Pilot Plants", Department of Health, Education and Welfare (DHEW) (NIOSH) Publication No. 78-120, January 1978.

- "Criteria for Recommended Standard, Occupational Exposure in Coal Gasification Plants", DHEW (NIOSH) Publication No. 78-191, September 1978.

2.4 Supplied Utilities

2.4.1 Coal Supply

The gasifier is designed to operate with a wide variety of coals. For each coal property, there is a considerable range acceptable to the gasifier. The flexibility of fuel supply is a major advantage of this process. During the operation of the Piñon Pine Power Project the predominant fuel will be low sulfur coals from the western U.S., with high sulfur coals from areas such as Pennsylvania being used for demonstration tests. The western coals used will be sub-bituminous and bituminous coals such as those found in Utah, Colorado, Wyoming, and Montana.

Coal in these states is abundant. Supplies will not only be available for the life of this project, but will also be available into the future. Currently, coal in this region is in an oversupply situation that has driven market prices down to levels last seen in the 1960's. SPPCo's economic forecast for fuel prices projects that these coal prices will remain stable in the future, and will not increase at rates exceeding general inflation.

SPPCo has interviewed major coal producers in the area who are able to supply required quantities from existing facilities at attractive prices.

All deliveries will be made by railcar to the Tracy facility. There are facilities of the Southern Pacific Railroad currently on-site.

2.4.2 Limestone

Sorbent requirements for in-bed desulfurization have been evaluated for the life of the project. High quality limestone supplies suitable for project needs have been available from several active producers in Nevada and western Utah. Although a variety of sorbents of various qualities are suitable for use as sorbents in the gasification process, optimum sulfur removal efficiency is achieved with maximum concentration of calcium carbonate.

Expected project requirements are approximately 80 tons/day of 90% + $CaCO_3$ limestone. The material is to be delivered to the site as limestone sand, 16 x 200 mesh, maintained dry so that no additional preparation is needed prior to injection into the gasifier. Dust-free truck transportation and storage is planned.

2.4.3 Natural Gas

Start-up and emergency backup fuel is provided by a 12" diameter pipeline, pressurized at nominal 500 psia utilized to provide natural gas to the combustion turbine. This line is on-site now, connecting to the Paiute gas transmission line at the plant boundary. This transmission line is the main line to the Reno area and its transmission capacity will accommodate the requirements of the project except for brief periods during the winter when use of natural gas for electric power generation is curtailed. During these periods, propane will be utilized.

2.4.4 Electric Power

The plant is within Sierra Pacific Power Company's service area. Construction power will be provided from existing buses, with electric power of 4.1 KV, approximately 100 feet from the project boundary.

2.4.5 Water Requirement and Availability

For the project, cooling water make-up will be taken from the existing cooling pond which is supplied from the Truckee River which adjoins the site, using an additional pump and existing water rights. Raw water for the demineralization train will be taken from deep wells. Two wells are currently in service and a new well with existing water rights will be added. SPPC serves water to 53,000 customers in northern Nevada and has extensive water management experience throughout the region. SPPC calculates that sufficient water rights exist to provide the Tracy site with the required water for the gasification process, the steam cycle, the cooling water and the balance of the plant through the year 2030.

2.4.6 Transportation System

Both highway and rail transportation will be used during the construction and operation phases of the project. The property is adjacent to I-80, a four-lane interstate highway. The site is served by the main line of the Southern Pacific Railroad which runs through the property. An extended rail spur for coal transport will be provided. Air transportation is available through Reno Cannon International Airport, a major airport located in Reno approximately 20 miles from the Tracy site.

2.4.7 Solid Waste Handling

Cooled solid waste consisting of ash, fines and sulfated limestone from the sulfation unit is conveyed continuously to the solid waste storage silo.

The solid waste material in the silo is loaded onto trucks by gravity during the day shift operation, 5 days per week. The silo is equipped to minimize dusting during the truck loading operation. The solid waste is then hauled to the lined landfill located approximately 2,000 ft. southeast of the process area. A local landfill has expressed interest in using the material as cover.

The solid waste silo is sized for three days of storage to handle the solid waste production over the weekend without the need of the truck load-out operation.

3.0 PROJECT DESCRIPTION

3.1 Combined Cycle

3.1.1 Gas Turbine Generator (Area 700)

A General Electric Model MS6001FA Gas Turbine Engine (70.1 MW ISO rating) has been selected as the prime mover for the Tracy 4 - Piñon Project. The engine's output shaft power will be reduced in rotative speed in a gearbox, from the optimum-efficiency value for a gas turbine of this size to 3600 RPM. Mechanical power will then be converted to electrical power in a once-through air-cooled synchronous generator.

The gas turbine generator, GT701, expected operating characteristics using syngas fuel at annual-average ambient air conditions (50°F, 12.56 psia, 20% RH) are as follows:

Output:		60,990 kW$^{(1)}$
Heat Input:		568.4 MMBtuLHV/h$^{(2)}$
Exhaust to HRSG,	flow:	1,422,000 lb/hr
	temp:	1,103°F

$^{(1)}$ = at the generator terminals, 0.85 pf
$^{(2)}$ = chemical release, i.e. does not include syngas sensible heat

Available thermal power in the exhaust gases will be captured in a heat recovery steam generator, SG801, (Section 800) to drive a condensing steam turbine generator.

The gas turbine has an eighteen stage axial flow compressor with modulated inlet guide vanes. Interstage extraction is used for turbine nozzle and wheelspace cooling. Because the blading material in the compressor has high corrosion resistance, a coating is not required. Approximately 20% of the total compressor discharge air is extracted from the engine for the air-blown gasifier, and returns as part of the syngas fuel.

The gas turbine engine is provided with a conventional array of auxiliary systems and accessory devices, supplemented where necessary by special provisions for gasifier air extraction and combustion of syngas. Gas turbine auxiliary systems and accessory devices include:

- Load gear
- Synchronous generator
- Excitation system
- Control panel
- Fuel system
- Lubrication oil system
- Starting system
- Inlet air/evaporative cooler system
- Compressor cleaning system
- Fire protection system
- Noise abatement

3.1.2 Steam Turbine Generator and Heat Recovery Steam Generator (Area 800)

3.1.2.1 Heat Recovery Steam Generator

A heat recovery steam generator (HRSG), SG801, is provided to recover the heat in the gas turbine exhaust gas stream. Two (2) levels of steam will be generated:

Level 1	1006.7 psia
Level 2	59.1 psia

Steam generated in the HRSG at 1006.7 psia, and high pressure steam generated in the Gasifier Island, are combined, superheated in the HRSG and sent to the steam turbine generator at 950 psia, 950°F for expansion. The 59.1 psia steam generated is superheated and sent at 55 psia, 360°F to the deaerator, DH801, for heating and stripping with the excess sent to the turbine generator, TG801.

The following items are included in the steam generator system:

D801	High Pressure Steam Drum
D802	Low Pressure Steam Drum
DS801	Main Steam Attemperator

3.1.2.2 Stack

The exhaust gasses exiting the steam generator and gasifier island will vent to the atmosphere via a 28' dia. x 225' high concrete shell stack.

The stack (ST801) contains two (2) insulated steel flues; one (1) 13' dia. and one (1) 4' dia.

The 13' dia. flue is dedicated to gas turbine exhaust while the remaining flue is dedicated to the gasification plant. The stack shall be equipped with test ports, interior access, lighting, aviation warning lights and lightning protection.

3.1.2.3 Steam Turbine Generator

The steam turbine generator, TG801, is a condensing type unit with extraction at nominally 485 psia providing steam, after pressure control and desuperheating, to the gasifier at 420 psia, 700°F. High pressure steam letdown is used if and when low throttle steam rates cause the extraction pressure to fall below that required to provide 420 psia steam. This letdown will provide steam for injection at the gas turbine generator at 420 psia, 700°F for NOx control when operating on natural gas.

The steam turbine exhausts into a surface condenser, E801. Cooling water from Section 1200 condenses the exhaust steam at 2 in. Hg, based on normal gasifier load at 50°F ambient temperature. Condensate is pumped from the condenser by the hotwell condensate pumps, P801 A/B, through the condensate preheater in the HRSG for the recovery of low level heat and then to the deaerator. Venting of the condenser is accomplished by a vacuum pump system.

HP boiler feed water is pumped from the deaerator to the high pressure evaporator and Section 300, Gasification, and Section 600, Sulfation by the high pressure boiler feedwater pumps, P803 A/B. High pressure boiler feedwater to the high pressure evaporator is preheated in economizer sections of the HRSG. Deaerated low pressure boiler feed water is pumped to the low pressure evaporator by the low pressure boiler feed water pumps, P802 A/B. Boiler feedwater to the low pressure evaporator is preheated in an economizer section of the HRSG.

The steam turbine generator will have an output of 46,226 kW at a power factor of .85, 329,133 lb/hr throttle flow, 11,855 lb/hr extraction @ 485 psia, 15,304 lb/hr induction at 54 psia and 360°F and 2.0 in.HgA exhaust backpressure.

A deaerator, DH801, shall be supplied to deaerate returned condensate and demineralized water make-up.

In addition, the following equipment shall be provided in the steam generation system:

DS802	M.P. Steam Desuperheater
DS803	Pegging Steam Desuperheater
E802	Gland Condenser
P804A/B	Vacuum Pumps
D803	Continuous Blowdown Drum
D804	Intermittent Blowdown Drum

3.2 Gasifier Island

The Gasifier Island is part of the Piñon Pine Power Project which has as its objective to provide a 107 MWe (gross) Integrated Gasification Combined Cycle (IGCC) power plant to meet the needs of the Sierra Pacific Power Company system while demonstrating the technical, economic and environmental viability of a commercial scale IGCC power plant. The design of the power plant is based on utilizing a KRW air blown, fluidized-bed coal gasifier installed in the Gasifier Island to produce a fuel gas for use by a combustion Gas Turbine which is capable of utilizing a low Btu fuel gas. Also, a hot gas clean up system is provided in the Gasifier Island to remove particulates and to minimize SO_2 and NOx emissions.

The M. W. Kellogg Company's (MWK) scope of work is to engineer, design and purchase equipment for installation in the Gasifier Island which is defined by the following areas:

Area 200 - Oxidant Compression & Supply
Area 300 - Coal Gasification
Area 400 - Gas Stream Heat Recovery
Area 500 - Gas Stream Particulate Removal
Area 600 - Desulfurization
Area 900 - Recycle Gas Composition

The equipment installed in these areas are: air compressors to supply process air to the gasifier and pressurize the coal and limestone feed system; coal and limestone feed systems; gasifier; exchanges to cool the product gas and recover heat for steam generation; hot gas filter; fixed bed desulfurizers with regenerative sulfur sorbent; and sulfator and combustor for sulfating solids from the gasifier and filter. During normal base load operation, the gasification system will:

1. Produce: 285,000 lb/hr syngas
2. Export: 156,000 lb/hr of steam for power production to the combined cycle area
3. Consume: 880 TPD Raw Coal
   50 TPD Limestone
4. Discharge: 120 TPD of LASH (limestone/ash mixture) for deposit to landfill

3.2.1 Coal Gasification (Area 300)

This area contains the solids feed system and the gasifier with its associated cyclone. Solids feeds consist of the coal to be gasified and limestone sorbent used for capture of sulfur compounds emitted during gasification.

Coal and limestone (as well as coke breeze during start-up) are fed from a single conveyor to the atmospheric feed surge bin, BN301, which is equipped with the feed surge bin vent filter, F302, to capture fugitive dust. This bin periodically discharges solids into feed pressurization hopper, BN302. After transfer of solids into BN302, it is isolated from BN301 and pressurized with air from the air receiver, D301. Pressurization is done through the hopper vent filter, F301, which back flows solids collected during the depressurization step back into BN302. After pressure equalization with the feed hopper, BN303, solids are transferred from BN302 to BN303. When BN302 is empty, it is isolated and depressurized to begin the next cycle. The feed hopper, BN303, is never emptied.

The feed hopper, BN303, provides a continuous feed of coal and limestone to the gasifier through the coal feeder, FD301. Solids from the feeder are picked up by transport air from E204 and fed directly to the gasifier central feed tube. Additional air from the recuperator, E201, is also fed through the same feed tube and the streams merge to form a central jet where the coal is quickly devolatilized, with the remaining char and limestone entering the bed. Combustion of char and gas occurs within the jet to provide heat necessary for endothermic devolatilization, gasification and desulfurization chemical reactions. Extraction steam from the steam turbine is also fed to the gasifier bed. Steam is injected at the gasifier grid to aid in fluidization of the gasifier bed. The primary gasification and combustion reactions which occur in the gasifier are:

$$C + H_2O \text{ ---> } CO + H_2$$
$$C + CO_2 \text{ ---> } 2CO$$
$$CO + H_2O \text{ ---> } CO_2 + H_2$$
$$C + O_2 \text{ ---> } CO_2$$

Carbon monoxide and hydrogen form the major combustible constituents of the product gas. Methane and other hydrocarbons are produced in lesser quantities, primarily from the devolatilization process. The operating temperature of the gasifier is sufficiently high to crack any tars or oils that might be produced.

Gasification also results in the release of sulfur from the coal, primarily in the form of hydrogen sulfide, H_2S. At gasifier operating conditions (nominal 295 psia and 1800°F gas exit), the limestone sorbent fed with the coal quickly calcines and reacts with the H_2S according to the following reactions:

$$CaCO_3 \longrightarrow CaO + CO_2$$

$$CaO + H_2S \longrightarrow CaS + H_2O$$

The amount of H_2S that is captured is limited by chemical equilibrium. With the low sulfur SUFCO Coal, approximately 50% of the sulfur released from the coal is removed from the gas by reaction with CaO. Sulfur exiting the gasifier in gaseous form is captured by the external desulfurizer system in Area 600.

The product gas exiting the top of the gasifier contains a significant quantity of entrained solids, consisting of char (unconverted coal), ash, and sorbent. The gas enters the gasifier cyclone, S301, which removes most of the solids. Gas from the cyclone is directed to the product gas cooler, E401, and the product gas trim cooler, E403, for heat recovery.

Solids collected in the gasifier cyclone, S301, are returned to the gasifier via the dipleg. Recycle gas from the recycle gas compressor, C901, is used to fluff the dipleg to facilitate flow of solids back to the gasifier bed. Recycle gas is also used to provide fluidization gas and for cooling of the spent solids in the annulus at the bottom of the gasifier.

As the carbon in char is consumed the particles become enriched in ash. The ash particles tend to agglomerate and along with dense calcium sulfide/oxide particles, separate from the char bed because of different density and fluidization characteristics. This separation occurs primarily in a region that surrounds the central feed tube at the bottom of the gasifier. These solids are further cooled in the gasifier annulus by a counter current stream of recycle gas. The spent solids leaving the gasifier are transferred via the ash feeder, FD302, to the ash collection hopper, BN501.

The gasifier and sulfator start-up heater, H301, heats the gas turbine extraction air to 1000°F for preheating the gasifier and downstream equipment during start-up.

3.2.2 Oxidant Compression and Supply (Area 200)

This area provides air to the gasifier, air for regeneration of the desulfurization sorbent, air for coal and limestone feed pressurization and transport air for feeding coal and limestone into the gasifier.

(2) Air for the gasifier island is extracted from the gas turbine's air compressor. A portion of this air is diverted for use during startup of the gasifier. The major portion of the air, which is the oxidant feed to the gasifier, must be compressed above gasifier operating pressure. To minimize power consumption during compression, this air is cooled to 110°F in three exchangers in series. E201 is the air recuperator which reheats the gasifier air after compression. Further cooling is done in the air precooler, E203, which heats BFW, and the trim cooler, E202, which uses cooling water for the final gas cooling. The knockout drum, D201, is provided downstream of the trim cooler to remove any water condensed from air during cooling. Any water collected will be sent to the waste water treatment system.

(2) A small portion of the air exiting the knockout drum is used for keeping the solids fluidized in the primary solids cooler E605 and for conveying waste solids to area 1100, the remainder is compressed by the boost air compressor C201 to above gasifier pressure level. A portion of this air is cooled by cooling water in the transport air cooler, E204, and is split into two streams. One of the streams is used as transport air to feed solids into the gasifier. The other stream is diverted to the suction of the pressurization air compressor, C301. The major portion of the air exiting the boost air compressor, C201, is reheated in the air recuperator, E201, and again divided into two

streams. A major portion of this stream is fed to the gasifier while the other portion is used for regeneration of the zinc oxide based desulfurization sorbent.

A portion of air exiting the transport air cooler is compressed to about 600 psia by C301 and sent to the pressurization air receiver, D301, which dampens out compressor fluctuations and serves as a surge vessel. Air from D301 is used directly for coal/limestone feed pressurization.

3.2.3 Gas Stream Heat Recovery (Area 400)

This area includes cooling of the main product gas from the gasifier as well as cooling of the recycle gas.

Product gas from the gasifier cyclone, S301, is cooled to about 1000°F in the product gas cooler, E401, and the product gas trim cooler, E403. Cooling is accomplished by generating steam from BFW supplied from the steam drum, SG401. Circulation through these two exchangers is by natural convection. The cooled gas from E403 is then passed through the desulfurizer feed cyclone S401. The larger particles collected in the cyclone are withdrawn by the cyclone fines feeder FD401 and transported to F501 using recycle gas. The smaller particles along with the cooled fuel gas are sent to the transport desulfurizer.

The particulate free, desulfurized product gas exiting the hot gas filter, F501, is cooled in the recycle gas cooler, E402. Cooling is accomplished by heating of high pressure BFW. A portion of the cooled gas is used for solids transport in the sulfator system. The major quantity is sent to Area 900 (recycle gas compression) for further treatment.

The gasifier steam drum, SG401, operates at 1075 psia (nominal) and is supplied by BFW from Area 800. Steam from the gasifier steam drum is combined with superheated steam from the HRSG steam drum, D602, and passed through the superheater section of the heat recovery steam generator, SG602, in order to superheat it to 600°F prior to delivery to Area 800. Blowdown from the gasifier steam drum is combined with blowdown from the HRSG steam drum and also returned to Area 800.

(2) The high pressure BFW at 230°F from Area 800 is split into several streams. A portion is sent directly to the air precooler, E203, and the recycle gas cooler, E402. Heated BFW exiting these exchangers is routed to the gasifier steam drum. The remaining BFW from Area 800 flows into HRSG steam drum, D602, after being preheated in the economizer section of SG602. BFW from SG401 flows to E401, E403, E605 and E607. The mixture of saturated BFW and steam from these exchangers flow back to SG401.

3.2.4 Gas Stream Particulate Removal (Area 500)

This area provides final cleanup of particulates in the product gas stream and collection of all spent solids prior to final processing.

Desulfurized product gas from the desulfurization section still contains a small quantity of particulates. This stream is sent to the hot gas filter, F501, which essentially removes all of the remaining particulates. The hot gas filter is a ceramic candle type utilizing back pulse gas for cleaning. Candle elements used for filtration are housed in a steel vessel with access capability for replacement of candles. The particulate free desulfurized gas exits the filter and is sent to the gas turbine.

(2) Blowback gas for cleaning of the filter elements in F501 is provided from the recycle gas booster compressor, C902. Fines removed by the filter elements are collected in the bottom of the filter vessel, which is aerated by recycle gas from the recycle gas compressor, C901, and discharged through the filter fines screw cooler, E501, which cools the filter fines to 500°F prior to discharging them into the filter fines collection hopper, BN503. Cooling is accomplished in E501 by a closed heat transfer fluid (UCON 500) system, PG501, which is cooled by cooling water.

The collected fines are sent to the filter fines collection hopper, BN503, for further processing.

2) Hoppers BN501/502/508 and BN503/504/507 are essentially parallel systems to collect and feed ash and filter fines, respectively. Ash is transported to BN501 with recycle gas. The exit gas from BN501 is combined with the product gas feed to the hot gas filter, F501. Ash collected in BN501 is discharged into the ash depressurization hopper, BN502, which is pressurized with high pressure recycle gas from the recycle gas receiver, D901. Pressurization is done through the ash vent filter, F502, which serves as a particulate filter during the depressurization cycle. Ash from BN502 is discharged into the ash feed hopper, BN508, from where it is continuously withdrawn by the ash screw feeder, FD502, and transported to the sulfator by cooled recycle gas stream from E402. The fines collection and feed system is operated in a similar manner utilizing the filter fines collection hopper, BN503, filter fines depressurization hopper, BN504, filter fines feed hopper, BN507, and the filter fines vent filter, F503. Filter fines from BN507 are withdrawn by the filter fines screw feeder FD503 and conveyed by a stream of recycle gas to the fines combustor, H602. Vent gas from the ash depressurization hopper and the filter fines depressurization hopper is routed to the sulfator.

3.2.4 Desulfurization (Area 600)

This area desulfurizes the product fuel gas prior to delivery to the hot gas filter, FG501, and conditions the solids waste for disposal.

- Desulfurization (Fuel Gas):

2) Fuel gas from the desulfurizer feed cyclone, S401, is fed to the fuel gas desulfurization system. Sulfur compounds are removed from the gas by a zinc oxide based sorbent, which also contains nickel oxide, according to the following reactions:

$$ZnO + H_2S \text{ ----> } ZnS + H_2O$$

$$ZnO + COS \text{ ----> } ZnS + CO_2$$

$$NiO + H_2S \text{ ----> } NiS + H_2O$$

$$NiO + COS \text{ ----> } NiS + CO_2$$

(2) The sulfur compounds in the product gas to the gas turbine are reduced to 20 ppmv.

(2) The fuel gas desulfurization system comprises a transport desulfurizer, R603, and a transport regenerator, R604. The fuel gas from S401 is fed to the mixing zone at the bottom of the riser of R603 where it mixes with zinc oxide based sorbent from the desulfurizer cyclone, S603, that is recirculated to the riser via the standpipe. Absorption of gaseous sulfur compounds takes place in the narrower riser section as the fuel gas and sorbent flow upward and into S603.

(2) The sorbent leaving the riser of R603 is partially sulfided. Bulk separation of the gas and solid phases takes place in S603. The solids separated in S603 are collected in the standpipe from where a portion of the sulfided sorbent is transferred to the regenerator and the remainder is recirculated to the desulfurizer. The fuel gas leaving S603 is desulfurized and flows to the hot gas filter, F501, where it undergoes final particulate (fines escaping the gasifier cyclone and attrited sorbent) removal before being fed to the gas turbine.

(2) Fresh sorbent from bulk storage is dumped into the sorbent storage hopper, BN603, pressurized in the sorbent feed hopper, BN604, and fed to R603 via the standpipe to maintain sorbent inventory and reactivity. Due to a large system inventory coupled with low projected sorbent losses, the make-up sorbent addition is required on a periodic basis. Sorbent fines escaping BN604 are collected in the sorbent pressurization hopper vent filter, F605. Vent gas from BN604 is discharged to the atmosphere.

The stream of sulfided sorbent withdrawn from the standpipe flows to the mixing zone at the bottom of the transport regenerator, R604. Regeneration air from E201 is preheated in the sorbent regeneration air heater, H608, and is also fed to the mixing zone of R604. The sulfided sorbent is regenerated by air according to the following highly exothermic reactions as both the sorbent and air flow up the regenerator riser:

$$2ZnS + 3O_2 \text{ ---> } 2ZnO + 2SO_2$$

$$2NiS + 3O_2 \text{ ---> } 2NiO + 2SO_2$$

2) (2) Provision has been made to bypass a portion of the air around the heater, if desired, and feed it directly to the riser of R604.

2) (2) The temperature of the gas exiting the regenerator riser is approximately 1300°F and is controlled by varying the inlet temperature of the regeneration air and the circulation rate and sulfur loading of the sulfided solids. The mixture of regenerated sorbent and gaseous products of regeneration leaving the riser enter the regenerator cyclone, S604, where bulk separation of the solids and gaseous phases occurs. The regenerated sorbent is returned to the standpipe of R603. The SO_2-rich gas from regeneration is cooled in the regenerator effluent cooler, E607, and then routed to the sulfator, R602, for SO_2 capture.

2) (2) During normal operation, it is not required to drain any sorbent out of the desulfurizer system. Sorbent may be withdrawn from the desulfurization system through low point drains after shutdown of the system and cooling of the solids.

- Waste Solids Treatment:

With the exception of a small quantity of sulfur in the fuel gas to the gas turbine, all of the sulfur in coal is ultimately disposed of in the sulfator system. This system serves the following functions:

1. Combustion of residual char in the ash and fines collected from gasification.

2. Capture of SO_2 from both the residual char combustion and the desulfurizer regeneration effluent gas.

3. Oxidation of calcium sulfide (CaS) produced in the gasifier to calcium sulfate.

The sulfur reactions which occur in the sulfator can be represented by the following equations:

$S + O_2 \text{ ----> } SO_2$

$CaO + SO_2 + 1/2\ O_2 \text{ ----> } CaSO_4$

$CaS + 2O_2 \text{ ----> } CaSO_4$

(2) All of these reactions are highly exothermic and may not proceed to completion.

(2) The sulfator, R602, is a bubbling bed reactor which is fluidized by air supplied by the sulfator air compressor, C601. Solids exiting gasifier bottom which contain unconverted calcined limestone, sulfided limestone and ash (LASH) are conveyed from the ash feed hopper, BN508, to the sulfator with cooled recycle gas from the recycle gas cooler, E402. Regeneration effluent gas from the desulfurization system is also fed to the sulfator for capture of SO_2 by reaction with the unconverted calcined limestone in the solids from the gasifier. Also, a small recycle gas stream (transport and pressurization gas) is combusted in the sulfator.

(2) Provision has also been made to add additional fresh limestone, from the limestone feed hopper, BN505. Instrument air is used to pressurize BN505 to add fresh limestone to the sulfator during normal operation. Any fugitive dust from BN505 is captured by the limestone feed hopper vent filter, F504. During the start-up, air from C601 is preheated in the gasifier and sulfator start-up heater, H301, and passed through the sulfator and downstream equipment.

(2) The sulfator is operated at essentially atmospheric pressure. In order to maximize SO_2 capture and sulfide oxidation, the sulfator temperature is maintained at about 1600°F. This is done by generating saturated steam in the primary solids cooler, E605, which is supplied with boiler feed water from the HRSG steam drum, SG402, by natural convection. Steam generated in E605 is collected in SG402. Fluidization air for the cooler is taken from D201 and exhausted to the freeboard section of the sulfator. Flue gas leaving

the sulfator passes through the sulfator cyclone S601 for removal of particulates and is then admitted to the fines combustor, H602, for use as quenching medium. Gas exiting H602 is cooled in the heat recovery steam generator, SG602, to about 350°F. The gas then passes through the sulfator flue gas bag filter, F602, for final removal of particulates and is sent to the stack. Particulates collected in F602 are transported to the fines surge pot BN608A by the bag house screw conveyor CR608. From BN608A solids are periodically transferred to the fines transfer pressure pot BN608 and then pneumatically conveyed to Area 1100 for storage prior to disposal.

Filter fines from FD503 are conveyed by a stream of recycle gas to the fines combustor, H602, to burn off carbon for additional heat recovery. Air for combustion, quenching the temperature to about 1800°F, and for supplemental fuel (natural gas) firing in H602 is supplied by the fines combustor air compressor C602.

Gas cooling in SG602 is accomplished by generating steam at 1075 psia and preheating BFW, respectively. Additional saturated steam is generated in HRSG coils with boiler feed water supplied from D602 by natural circulation. Deaerated boiler feed water from Area 800 is heated in the economizer section of SG602 prior to transfer to D602.

Saturated steam generated in HRSG and solids coolers is collected in D602, mixed with steam from SG401 and passed through the superheater section of SG602 to superheat to 600°F (approximately 50°F superheat at battery limit pressure of 1020 psia) prior to exporting it to Area 800. Blowdown from D602 is combined with blowdown from SG401 and is also exported to Area 800.

Solids leaving the bottom of the sulfator are cooled in the sulfator solids screw cooler, E602, and collected in the sulfator solids collection hopper, BN601. These are then combined with solids collected in the sulfator flue gas bag house filter, F602, in the sulfator solids depressurization hopper, BN602, which is pressurized by instrument air and also collects solids from BN601. Solids from BN602 are discharged on to a conveyor for transfer to Area 1100.

3.2.6 Recycle Gas Compression (Area 900)

This area provides for recompression and distribution of recycle gas to various users.

(2) Recycle gas from the recycle gas cooler, E402, is split into three streams. A portion is sent directly to the sulfator system for use as transport gas. A second stream is compressed by the recycle gas compressor, C901, to gasifier pressure for recycle directly to the gasifier and for use as fluffing gas in the desulfurizer riser and the bottom of the hot gas filter. A portion of this gas is also used as transport gas to transfer ash from the bottom of the gasifier to BN501 and to transfer solids from the bottom of S401 to F501.

(2) A third stream is further cooled in the recycle gas booster compressor trim cooler, E901, to 90°F before compression. Cooling results in condensation of a small amount of water from gas which is removed in the recycle gas knockout drum, D902, and is disposed of by vaporizing it into the air feed to the fines combustor. The cooled gas from D902 is fed to the recycle gas booster compressor C902 which boosts the pressure to about 800 psia (1200 psia maximum, if required) for use as blowback gas for the hot gas filter. A portion of the gas from the intermediate stage of the compressor is withdrawn at about 600 psig and sent to the recycle gas receiver, D901, which acts as a surge vessel. Gas from D901 is used for pressurization of the ash depressurization hopper, BN502, and the filter fines depressurization hopper, BN504.

3.3 Offsites

3.3.1 Solids Receiving and Grinding (Area 100)

3.3.1.1 Raw Coal Receiving and Storage

Raw coal, size 2" x 0, is received at the plant from a unit train consisting of up to eighty-four 100 ton railcars every seven days. The coal is received at the unloading station and transferred to the coal storage dome. The unloading station will be enclosed and provided with a dust collection system to avoid uncontrolled coal dust emissions. The unloading station consists of two receiving hoppers, each equipped with a belt type unloading feeder which feeds the raw coal to the raw coal transfer conveyor. Coal is weighed in transit by the raw coal receiving scale located at the tunnel exit of the raw coal transfer conveyor. A sweep type automatic sampling system is installed on the coal transfer conveyor, and located after the conveyor tunnel exit, to collect a representative raw coal sample to determine the quality of coal received. The raw coal unloading and conveyor system is sized to handle an 84 railcar train unloading operation in a four-hour period, at a design rate of 2,250 std. tons/hr. The raw coal receiving system consists of the following major components:

Item No.	Description	Duty
BN101A/B	Raw Coal Receiving Hoppers	100 std. tons each
FD101A/B	Raw Coal Receiving Feeders	1,125 std. tons/hr each
CR102	Raw Coal Transfer Conveyor	2,250 std. tons/hr
WS101	Raw Coal Receiving Scale	2,250 std. tons/hr
F106	Coal Receiving Dust Filter	58,800 ACFM
B105	Coal Receiving Exhaust Fan	58,800 ACFM
Item No.	Description	Duty
CR111	Filter Discharge Conveyor	4.3 std. tons/hr
FD111	Receiving Filter Airlock Feeder	4.3 std. tons/hr
PG103	Raw Coal Sampling System consisting of:	2,250 std. tons/hr
	CR116 Sample Rejects Bucket Elevator	
	FD116 Primary Sample Feeder	
	FD118 Secondary Sample Feeder	
	SR103 Primary Sample Crusher	
	SS103 Primary Sampler	
	SS104 Secondary Sampler	
P101A/B	Sump Pump	100 GPM vs 35 TDH

The coal is stored in a 250' diameter field erected storage dome which will be sized to store 16,400 std. tons of coal, or approximately twenty day's requirement. No exposed storage of coal, such as a coal pile, is planned, thus all coal storage will be within the dome. The material in the coal storage dome is stockpiled and reclaimed by an automated circular coal pile stacker/reclaimer assembly. The raw coal is discharged through a vibratory feeder onto the raw coal collecting conveyor. This conveyor transfers the coal to the crushing station for sizing and screening. In the event of an emergency, there are also provisions to discharge the stockpile through an emergency reclaim hopper equipped with a feeder into the raw coal collecting conveyor. The coal storage system consists of the following major components:

Item No.	Description	Duty
X100	Coal Storage Dome	16,400 std. tons
CR105	Raw Coal Collecting Conveyor	340 std. tons/hr
SE101	Raw Coal Magnetic Separator	340 std. tons/hr design
F107A/B/C	Raw Coal Storage Dust Filters	2,500 ACFM (each)
B106A/B/C	Raw Coal Storage Exhaust Fans	2,500 ACFM (each)
PG102	Stacker Reclaimer Package consisting of:	
	CR118 Stacking Conveyor	2,250 std. tons/hr
	RL101 Coal Pile Reclaimer	110 std. tons/hr normal 340 std. tons/hr max.

Item No.	Description	Duty
FD114	Coal Pile Discharge Feeder	110 std. tons/hr normal 340 std. tons/hr max.
BN108	Emergency Reclaim Hopper	
P103A/B	Reclaim Tunnel Sump Pump	50 gpm vs 70 TDH

3.3.1.2 Coal Crushing and Screening

In coal crushing and screening, the raw coal passes through a magnetic separator to remove tramp iron and is then screened through a dual deck vibrating screen, which will control the product gasifier feed size of ¼" x 0 through the ¼" square holes of the lower deck of the vibrating screen. The oversize material from the upper deck will be fed to the coal crusher to bring the material size from 2" x 0 to the required ¼" x 0. This sized product is recycled to the dual deck coal screen through flexible wall elevating conveyors. The ¼" x 0 product-size material is transported into the coal storage silo utilizing an elevating flexible wall conveyor. The coal silo is sized for 24-hour feed to the gasifier and is filled daily during an 8 hour period operation of the crusher and the elevating conveyor.

A common single gasifier feed elevating conveyor system is provided from the coal and/or start-up coke silos and the limestone silo to the gasifier area. The conveying system consists of a weigh belt feeder from each silo and the common elevating conveyor. The system will be operating continuously during feeding of the gasifier. As with the raw coal handling system, care will be taken to control any dust emission sources by means of dust collection system. The coal crushing and screening system consists of the following major components:

Item No.	Description	Duty
B111	Crushing Station Dust Filter Fan	19,750 ACFM
FD115	Crushing Station Dust Filter Feeder	2.0 std. tons/hr
CR114	Oversize Coal Elevator	125 std. tons/hr
CR115	Sized Coal Conveyor	50 std. tons/hr
F109	Crushing Station Dust Filter	19,750 ACFM
SE104	Coal Screen	235 std. tons/hr
SR102	Coal Crusher	125 std. tons/hr
FD117	Oversize Coal Feeder	125 std. tons/hr
BN109	Emergency Surge Hopper	20 std. tons/hr
CR117	Emergency By-pass Conveyor	340 std. tons/hr
DV105	Coal By-pass Diverter	340 std. tons/hr
DV106	Coal Dust By-pass Diverter	2.0 std. tons/hr

3.3.1.3 Coal, Coke and Limestone Feeding

Dried coke breeze, ¼" x 0, is received in the plant via trucks, to be used for initial plant start-up and for each subsequent gasifier start-up. The sized coke is transferred from the truck pneumatically to an 800 ton capacity coke storage silo using the truck-trailer's own pneumatic blower. Exhaust air from the filling operation will be vented through a dust control filter installed atop the coke silo. The material from the coke silo is conveyed to the gasifier utilizing the common coal/coke/limestone elevating conveyor. The coke silo will be equipped with a constant speed weigh feeder provided with a feed depth regulating valve to feed the required coke to the common elevating conveyor.

Sized limestone is received at the job site via trucks with pneumatic trailers on a daily basis. The sized limestone is conveyed pneumatically to a 300 ton (6-day) capacity limestone storage silo using the truck trailer pneumatic blower. Exhaust air from this filling operation will be vented through a dust control filter installed atop the limestone silo. The material from the limestone silo is then fed at a controlled rate by a variable speed weigh feeder and blended with the coal on the same elevating conveying line feeding the gasifier. Provisions are also included to transport limestone to the sulfator limestone feed hopper by pneumatic conveying. The material is discharged from the limestone silo and distributed to the two conveying lines utilizing a bifurcated feed line. The pneumatic conveying line to the sulfator will be provided with the required conveying air blower and a stand-by air blower. The coal, coke and limestone feeding system consists of the following major components:

Item No.	Description	Duty
BN105	Coal Silo	818 std. tons
BV102	Coal Silo Discharger	15-50 std. tons/hr
FD106	Coal Silo Discharge Feeder	15-50 std. tons/hr
F102	Coal Silo Dust Filter	2,500 CFM

Item No.	Description	Duty
F105	Gasifier Feed Dust Filter	3,700 ACFM
B104	Gasifier Feed Dust Collection Fan	3,700 ACFM
BN106	Coke Silo	800 std. tons
BV103	Coke Silo Discharger	15-50 std. tons/hr
FD107	Coke Silo Discharge Feeder	15-50 std. tons/hr
F103	Coke Silo Exhaust Filter	1,250 CFM
BN107	Limestone Silo	300 std. tons
BV104	Limestone Silo Discharger	1.5-5.0 std. tons/hr
B112	Coal Silo Fan	2,500 ACFM
F104	Limestone Silo Exhaust Filter	1,250 ACFM
FD108	Limestone Silo Discharge Feeder	1.5-5.0 std. tons/hr
CR110	Gasifier Feed Elevating Conveyor	50 std. tons/hr
SE102	Gasifier Feed Magnetic Separator	50 std. tons/hr
WS102	Truck Scale	100 std. tons
D104	Limestone Transporter	4 std. tons/hr

3.3.1.4 Dust Collection System

Dust collection systems will be provided in the plant for proper environmental control. Fabric filter collectors will be used to control fugitive dust emissions from the transport and transfer of coal, coke and limestone.

All material handling systems are enclosed and will be supplied with dust collection systems for environmental control, with special attention being paid to dust generating areas, mainly transfer points.

3.3.2 Solid Waste Handling (Area 1100)

Cooled solid waste consisting of ash, fines and sulfated limestone (LASH) from the sulfation unit is conveyed continuously to the solid waste storage silo using a pneumatic conveying system. The air displaced from the silo is vented through the bin filter, installed atop the solid waste silo.

The LASH in the silo is loaded-out onto trucks during the day shift operation, 5 days per week. The silo is equipped with a bin discharger, discharge valve and a telescopic loading chute with a bag filter and fan to minimize dusting during the truck loading operation. The LASH is then hauled to the final disposal point. A local landfill has expressed interest in using the material as a cover, and other usages are being investigated.

The solid waste silo is sized for three days of storage (400 tons) to handle the solid waste production over the weekend without the need of the truck load-out operation. The solid waste handling system consists of the following major components:

BN1101	Solid Waste Bin		400 std. tons
BV1101	Solid Waste Discharger		100 std. tons/hr
PG1101	Sold Waste Load-Out package consisting of:		
	B1102	Load-Out Exhaust Fan	1,000 SCFM
	CH1101	Solid Waste Loading Chute	100 std. tons/hr
	F1102	Load-Out Filter	1,000 SCFM
	XV1101	Load-Out Slide Gate	100 std. tons/hr
F1101	Silo Vent Filter		2,500 CFM

3.3.3 Balance of Plant (Area 1200)

3.3.3.1 Raw Water System

The raw water system provides water to the demineralization package, PG1201, which in turn provides boiler feedwater makeup to the deaerator, DH801. Additionally the raw water system provides water for the plant utility water system for miscellaneous users such as service wash stations. Well water from Well No. 4 is the source of water for the plant raw water system. Well water is pumped to the existing Unit 3 raw water tank and then pumped by the raw water pumps, P1202A/B, to the plant raw water system.

Potable water for safety showers and eyewashes will be provided from Well No. 4. Drinking water is provided as a brought-in bottled source.

3.3.3.2 Boiler Feedwater Supply and Storage

Makeup boiler feedwater is demineralized by a package, PG1201, consisting of cation, degasification, anion and mixed bed units. Also included are the storage and feeding of regenerating caustic and sulfuric acid, and appropriate local controls, including neutralization controls. Spare acid and caustic pumps and the neutralization mixing system are also included.

Regeneration waste is stored in a neutralization tank, TK1202, where the waste is mixed and neutralized before it is sent to the waste water treatment system. Acid and caustic pumps are provided for neutralization.

Demineralized water is stored in TK1201 and pumped to the deaerator by the demineralized water pumps, P1208 A/B.

This system shall produce demineralized water from raw well water for BFW make-up at a rate of 280 GPM. The demineralization system consists of the following major components:

Item No.	Description
D1203A/B	Cation Units
T1201	Degasifier
D1204A/B	Anion Units
D1211A/B	Mixed Bed Units
P1203A/B	Acid Regeneration Pumps
P1204A/B	Caustic Regeneration Pumps
P1205	Acid Neutralization Pump
P1206	Caustic Neutralization Pump
P1217A/B/C	Booster Pumps
B1202A/B	Degasifier Blowers
E1201A/B	Caustic Water Heaters
D1201	Acid Storage Drum (8' - 0" dia. x 10' - 0" T-T)

Item No.	Description
D1202	Caustic Storage Drum (8' - 0" dia. x 13' - 0" T-T)
TK1201	Demineralized Water Tank (12' - 0" dia. x 32' - 0" high)
P1208A/B	Demineralized Water Pumps
TK1202	Neutralization Tank (12' - 0" dia. x 32' - 0" high)

3.3.3.3 Boiler Water Treatment System

A package of chemical dosing equipment will be provided for the conditioning of the boiler water. The boiler water treatment system consists of the following major components:

Item No.	Description
TK1203A/B	Phosphate Tanks
M1201A/B	Phosphate Tank Mixers
P1211A-E	H.P. Phosphate Pumps
P1212A/B	L.P. Phosphate Pumps
TK-1207	Oxygen Scavenger Dilution Tank
M-1204	Oxygen Scavenger Dilution Mixer
P1210A/B	Oxygen Scavenger Pump
TK-1204	Amine Dilution Tank
M-1203	Amine Dilution Mixer
P1213A/B	Amine Pump

3.3.3.4 Cooling Water System

The cooling pond provides makeup water for the cooling tower, CT1201. Pond water is pumped from the existing pond water pump structure to the cooling tower basin by the make-up pump, P1201.

A conventional induced-draft 3-cell counter-flow cooling tower, CT1201, will be used for the plant cooling water system. The top of basin is 3' - 6' above grade. Cooling water is circulated through the system by cooling water pumps, P1209A/B/C.

The cooling tower is designed for the 2½% occurrence condition of a 61°F wet bulb temperature and provides 80.5°F cooling water at that condition.

Biocide injection is provided by a biocide feeder. Other additives, corrosion inhibitors, pH controlling, and scale/deposit inhibitors are injected into the cooling water by the circulating water treatment system, PG1202. The cooling water system consists of the following major components:

Item No.	Description
CT1201	Cooling Tower
P1209A-C	Cooling Water Pumps
D1209	Acid Drum
P1215A/B	Acid Pumps
FD1201A/B	Biocide Feeders
P1223A/B	Copper Corrosion Inhibitor Pumps
P1226A/B	Scale Inhibitor Pumps

3.3.3.5 Instrument and Plant Air System

A conventional plant and instrument air compression system is provided. Two air compressors, one operating, one spare, are provided for the system. A single air receiver provides adequate surge capacity. The air is dried to a -40°F dewpoint using an air drying desiccant system prior to branching off to plant and instrument air headers.

The following equipment is provided to supply both Instrument and Plant Air:

Item No.	Description
C1201A/B	Instrument & Plant Air Compressors
D1207	Air Receiver
DR1201A/B	Air Dryers

3.3.3.6 Flare System

A flare system is provided to incinerate the full product gas flow from the gasifier in the event of a power plant outage, gasifier start-up, or other emergencies. The flare, FL1201, is a vertical free-standing system. Pilots will be designed to use natural gas.

A 48" dia. x 60' - 0" flare stack with a capacity of 290,498 lbs/hr will be provided.

3.3.3.7 Nitrogen System

Nitrogen is required for maintaining a constant flow of purge gas through selected equipment and instruments, blow back cleaning of the hot gas filter (when normal process gas is unavailable), and system purging at shutdown.

The Nitrogen Package, PG1205, is a cryogenic air separation plant wherein the constituents of air are separated by cryogenic distillation delivering high purity nitrogen (99.7%) in the required quantity.

Components of the package include compressors, storage tanks, a liquid nitrogen pump and vaporizers sized to provide for start-up, normal operation and a safe shutdown of the facility.

3.3.4 Waste Water Treatment System

Regeneration waste from the demineralization system and a sidestream from the cooling tower is sent to the wastewater treatment system.

This system will soften and clarify these streams and return the treated water to the cooling tower basin except for a small blowdown flow, which will be sent to a waste evaporation (cooling) tower.

The sludge generated in the clarifier will be thickened and dewatered. The supernatant water from these processes is recycled within the waste treatment system.

Blowdown from the evaporation tower is discharged to a six acre evaporation pond.

The pond will be double lined and the system will be designed to meet the requirements of the Nevada Division of Environmental Protection. The wastewater is not anticipated to result in any adverse effect on wildlife such as migrating water fowl. Monofilament line with 25' spacing has been used by SPPCo to successfully discourage migrating water fowl from landing in several of SPPCo's facilities and is unobtrusive to the human observer.

The system consists of the following items:

Item No.	Description
CL1001	Reactor Clarifier
CT1001	Waste Evaporation Tower
D1001	Caustic Drum
D1002	Acid Drum
E1001	Circulating Brine Exchanger
F1001	Plate Filter Press
F1002	Gravity Filter
FR1001	Soda Ash Feeder
P1001A/B	Dirty Waste Water Pumps
P1002A/B	Clean Waste Water Pumps
P1004A/B	Blowdown Pumps
P1005A/B	Sludge Pumps
P1006A/B	Sludge Recirculation Pumps
P1007A/B	Caustic Pumps
P1008A/B	Soda Ash Pumps
P1009A/B	Magnesium Sulfate Pumps
P1010A/B	Acid Pumps
P1011A/B	Scale Inhibitor Pumps
P1012A/B/C	Brine Circulation Pumps
P1013	Cationic Polymer Pump
P1014	Anionic Polymer Pump
P1016A/B	Concentrator Cooling Water Pumps
P1017A/B	Flocculator Feed Pumps
P1018A/B	Waste Water Treatment Sump Pumps
P1019	pH Adjustment Pump
S1001	Oil/Water Separator
TK1001	Equalization Tank
TK1002	Magnesium Sulfate Tank
TK1003	Soda Ash Dissolving Tank
TK1004	Flocculator Tank
TK1005	Sludge Tank
TK1006	pH Adjustment Tank

3.4 Electrical Distribution

The existing Tracy sub-station is supplied at 120 KV by SPPCo. Connection to this system will be through tie and service breakers feeding unit transformers connected to the gas and steam turbo-generators. The generators will be rated at 13.8 KV with maximum generator output equal to elevated temperature and/or auxiliary cooling transformer rating as required. The auxiliary power will be fed from each generator transformer servicing large motors 250 hp and over at 4.16 KV and 480 V for general distribution. The 4.16 KV and 480 V will be radial distribution. A second feeder from an existing 4.16KV transformer will permit alternate service in the event of maintenance turnarounds or equipment outages. However, this transformer will not be able to carry the coal gasification process in addition to the generator auxiliaries.

Metering will be on the 120 KV system for assessment. Additional metering will be furnished for gasifier, steam plant, material handling and auxiliary services. Protection will be arranged as required to coordinate with the SPPCo system and internal users.

Auxiliary systems within the plant will be serviced by UPS or DC Batteries to support personnel safety and critical equipment during shutdowns or power outages.

3.5 Instrumentation

3.5.1 Digital Control System (DCS)

Plant process and supervisory control shall be performed with a DCS "Process Manager" type redundant processor located in the main control building. DCS I/O cabinetry will be mounted close to the entry point of the field wiring into the Control Room. The cabinetry will contain the I/O terminals, I/O processing equipment, the controller files for the DCS, and all interconnecting vendor prefabricated cables. Redundant DCS network cables interconnecting the equipment mounted in the I/O cabinetry and the DCS operator's consoles will be vendor prefabricated "coax" cables. Gasifier Island signals will be interfaced with the DCS operators console via a remote I/O unit located in the Gasifier Remote Instrument Enclosure (RIE) (see

Section 3.5.5). The DCS will comprise equipment, hardware, and software of one single manufacturer, and be "equal" in functionality, quality, and proven operability, to the TDC-3000 LCN, UCN, and Process Manager product line as manufactured by Honeywell, Inc., Phoenix Arizona.

The DCS will be purchased, configured and tested by FW USA.

3.5.2 Continuous Emission Monitoring System (CEMS)

Two (2) CEMS shall be provided for monitoring of CO, SO_2, NOx, O_2, opacity and flow. The systems shall be housed in an enclosure with HVAC and sampling systems. A Data Acquisition System (DAS) shall be provided with the PC located in an analyzer house. The systems shall be certified by the system vendor's subcontractor to be in compliance with all federal and state requirements.

3.5.3 Water/Steam Analysis

A panel shall be provided with analyzers to analyze/monitor the following constituents in the boiler water and steam systems:

a. Dissolved Oxygen (DO)
b. Hydrazine
c. Sodium
d. Ammonia
e. pH
f. Silicates (S_1O_2)
g. Conductivity
h. Hydrogen

The above analyzers shall be mounted in a "dry" section of the panel. A "wet" section shall be provided for the sample conditioning systems, sink, etc.

3.5.4 Shutdown and Safety Systems
(Synonymous with Emergency Trip System - ETS)

3.5.4.1 Design

a. The ETS will be hard-wired relay logic (preferred) or solid state system programmed in firmware (ROM or EPROM) with a predictable failure action.

b. "Hard-wired" is defined as a design which provided signals which are independent of any soft link such that shutdown alarms and control will be available with the loss of both DCS highways.

c. ETS equipment will be housed in panels located both in the Control Room and the RIE in the Gasifier Island (see Section IV).

d. All ETS field wiring shall be terminated in the normal field J.B.s being used for control wiring; however, the multi-conductor cables between the field J.B.s and the Control Room (home-run cables) shall be segregated by type (i.e. ETS signals in dedicated home-run cables).

e. All safety shutdowns will be de-energize-to-trip fail-safe design.

3.5.4.2 Alarms

a. Two types of safety and shutdown alarms will be provided (listed in order of priority):

- Shutdown
- Pre-shutdown

b. Each equipment and safety shutdown alarm will be redundant with the following wiring:

- One signal will be hard-wired from the device to an indicator mounted on the ETS panel.

- The other signal will be input to the DCS for data logging.

c. Pre-shutdown alarms will be input to the DCS for data logging (hard-wiring not required).

3.5.4.3 Switches

a. All equipment with safety shutdowns will have a hard-wired manual shutdown switch on the Control Room ETS panel.

3.5.4.4 Maintenance

a. Shutdown bypass switches are required for any shutdown or safety system that must remain in service during alarm testing with the plant in operation.

b. When bypass switches are required they will be provided for each device that inputs a signal to a shutdown or safety system.

c. Each safety shutdown system having bypass switches will have a common hard-wired "S/D BYPASS" indication light on the ETS panel, as well as an alarm in the DCS.

3.5.5 Remote Instrument Enclosure

1. A Remote Instrument Enclosure (hereafter termed RIE) will be provided by MWK for housing the following Gasifier Island equipment.

   a. DCS remote I/O unit
   b. Shutdown and Safety System (ETS) equipment
   c. PLC equipment

2. The RIE will be located inside the Gasifier Island boundaries.

3. DCS communications from the Gasifier Island RIE to the operator console in the Control Room will be via co-axial cable or fiber optic link.

4. All Gasifier Island shutdown signals will follow the plant hard-wire philosophy.

5. The RIE's sole purpose is to provide a controlled environment for equipment; therefore, no provisions are to be made for this to be used as a remote operations center.

3.6 Fire Protection System

Current plant fire protection for the steam plant area will be, as a minimum, per NFPA 850, "Fire Protection for Electric Generating Plants".

A. Fire water supply: existing plant underground loop system

B. Scope of supply:

1. 10" dia. U/G piping from existing plant loop system extended throughout for service to new equipment areas including gasifier island. Yard piping shall include fire hydrants, hose houses and P.I.V.'s (post indicator valves).

2. Sprinkler systems (dry pipe or deluge as required for the following areas:

- steam turbine generator
- administration building
- maintenance building
- coal handling systems

3. CO_2 System

- gas turbine and accessory compartments

3.7 Buildings

Due to the relatively average site conditions, the use of enclosures will be minimized. The steam turbine generator along with its auxiliary components (surface condenser, condensate pumps) and the water treating facilities, boiler feed water pumps, compressor and deaerator will be housed in a building. The gasifier will be supported in a steel structure but will not be enclosed. The gas turbine generator set and ancillary subsystems have their own, vendor-provided enclosures.

Two pre-engineered buildings will be constructed to provide new maintenance and machine shop facilities and administration offices. A car port of 40' x 120' will be built near the office and maintenance buildings.

a. Administration Building

The administration building will include the following:

- Reception Area
- Manager's Office and nine other single offices
- Lunch Room 6-8 people seating
- Conference Room (14 people)
- Toilet Facilities for men and women and jan. closet
- Locker and Shower booth. locker for 12 men and 8 women
- Utility Room
- Files/Prints/Storage Room
- Visitor Center - 30 people
- HVAC Facility for entire office building

The above will be in a pre-engineered building with typical office building finish, including windows for offices, gypsum board partition walls and acoustical tile ceiling. The size of the building will be 50' x 100'. Accessibility requirements of the Uniform Building Code will be followed.

b. Maintenance Building

The maintenance building will include the following:

- Maintenance Supervisor's Office
- Tool Storage
- Welding Area/Lath Benches
- Laydown Area
- Machinist's Work Area/Repair Shop
- Lunch Room - 10 people seating
- Toilet Facilities for men and women and jan. closet
- Locker and Shower Facility for 24 men and 6 women

The above will be in a pre-engineered 50' x 100' x 14' high building with insulated siding. Louvers and exhaust fans (roof) will be provided for ventilation. Utilities provided are water, gas, and sanitary sewer. A roll-up door 10' wide x 12' high will be provided at each end. A 2 ton monorail will be provided. Gypsum board partitions with view window and acoustic tile ceiling will be provided for the supervisor's office only.

All other equipment will be located outside without enclosures. Outside, small rotating equipment items will be provided as totally enclosed fan cooled or with equivalent protection.

Heated enclosures and/or heat tracing shall be provided for steam drum level controls, and any other system where freezing conditions may cause service interruptions.

3.8 Access Roads/Storm Water Treatment

A. Drainage and Erosion Control

1. Storm water control is based on zero discharge. A number of small retention basins will be created during the initial stage of construction.

2. All storm water during construction as well as during normal plant operation will be drained to the nearest basin.

3. Since the plant site receives very little precipitation, all of it will ultimately evaporate or be absorbed in the ground, and there will be no run-off.

B. Area Surfacing and Roads

1. Roads around combined-cycle area will be asphalt paved. Roads in material handling and outlying areas will be gravel or crushed stone finish. Also, all areas around major equipment foundations, cooling tower, stack and electrical substations will be gravel finish.

2. Heavy embankments or deep cut along the railroad spur and other places will receive riprap to protect the soil from erosion.

4.0 ESTIMATED PLANT PERFORMANCE

The following table shows the estimated plant performance at the plant average ambient condition of 50°F, 20% RH.

PIÑON PINE POWER PROJECT ESTIMATED PLANT PERFORMANCE	
	IGCC
Coal Feed (T/D)* (1)	880.6
Gas Turbine Power (MWe) (2)	60.99
Steam Turbine Power (MWe) (3)	46.23
Gross Power (MWe) (4)	107.22
Auxiliary Power (MWe) (5)	7.51
Net Power (MWe)	99.71
Net Heat Rate (Btu(LHV)/kWh)	8096
Net Heat Rate (Btu(HHV)/kWh)	8390
Thermal Efficiency (LHV) %	42.1
Thermal Efficiency (HHV) %	40.6

(1) As received and prorated from M. W. Kellogg H&MB dated 6/7/94, 569.4 mmB/hr of syngas @ 882.6 TPD coal input.
(2) Based on GE performance run dated 6/10/94, base load achieved at 568.1 mmB/hr syngas consumption.
(3) Based on GE steam turbine data dated 8/17/94.
(4) Based on FW USA ELCO (load list) dated 9/16/94.
(5) Does not include transformer or feeder losses to SPPCo connection.

5.0 PLANT EMISSION DATA

Plant emission rates are identified in Table 2. Air quality modeling conducted for the Environmental Impact Statement and the Nevada Division of Environmental Protection Agency Permit to Construct demonstrate compliance with Prevention of Significant Deterioration and National Ambient Air Quality Standards.

PROJECT EMISSION RATES

SOURCE	DAILY OPERATING HOURS	ANNUAL OPERATING HOURS	PM_{10} EMISSION RATE (g/s)	NO_x EMISSION RATE (g/s)	SO_2 EMISSION RATE (g/s)
CT/HRSG Stack	24	8760	2.52	16.0	1.94
Sulfation Combustor	24	8760	0.48	0.48	4.73
Flare	24	384	0.008	0.45	0.002
Coal Dryer	24	3000	0.10	0.057	0.0004
Feed Lockhopper	24	8760	0.0183	NA	NA
Cooling Tower	24	8760	0.014	NA	NA
Waste Water Cooling	24	8760	0.059	NA	NA
Railcar Unloading	6	730	0.27	NA	NA
Raw Coal Storage	24	3500	0.173	NA	NA
Coal Preparation	8	3000	0.216	NA	NA
Coal Day Bin	24	3000	0.043	NA	NA
Coke Storage Silo	24	2000	0.043	NA	NA
Lime Storage Silo	24	2000	0.043	NA	NA
Solid Waste Storage	24	8760	0.043	NA	NA
Gasifier Feed Vent	24	8760	0.108	NA	NA
Sulfator Depress. Vent	24	8760	0.0126	NA	NA
Sorbent Storage Vent	24	8760	0.00004	NA	NA

Appendix 2 – Project Safety and Compliance

1.0 Abstract

The Pinon Pine IGCC Project is a joint venture between Sierra Pacific Resources and the United States Department of Energy. The purpose of the project is to prove the design and operation of the KRW air blown Gasifier and the General Electric Frame 6 Combustion Turbine. Both of these are the first ever to be installed as a commercial project. The KRW Gasifier utilizes air-blown technology to gasify coal for use as fuel in the GE Frame 6 Turbine to produce electricity. Combined Cycle design utilizes the waste heat from the combustion turbine to generate steam that produces even more electricity in the GE Steam Turbine. In addition, the processing of coal into a synthetic gas (Syngas) proves to have significantly fewer emissions than standard coal-fired plants.

It was agreed by the DOE and SPPCo. that a significant safety program be developed pertaining to the IGCC project, insuring the well being of employees and insuring compliance with pertinent governmental regulations.

2.0 INTRODUCTION

In February of 1997 a core committee was formed to create appropriate safety procedures and policies pertaining to the operation of the IGCC project. Primary focus was placed on the coal gasification process. Planning stages included the site Safety Consultant visiting another gasification project to learn of their progress in a safety program.

The initial policies and procedures were completed in April of 1997. All existing plant employees and contractors received training in these items during the following two months. Since that time, any individual that desires or must perform a task in a Syngas area must and does receive this training and copies of the policies and procedures.

Safety policies and oversight have been effective during construction and start-ups of the gasification process. During construction over one million (1,000,000) man-hours were achieved without a lost time accident. Since that time, the work force has sustained one lost time accident associated with the IGCC project. This was a bruise on an employee's knee that required eventual minor surgery and resulted in time away from work. From 1996 to date, the facility's safety record has been in the top quartile of all of SPPCo. and maintaining rates greatly below the industry average. For the year 2000, the Tracy/Pinon site is the only SPPCo. generating station with an OSHA incident rate of zero (0). Incident Rate is defined as the number of OSHA Reportable incidents times 200,000 divided by total number of man-hours worked. OSHA Reportables are any injury or illness that require medical treatment, light duty or result in lost time (unable to report for the next scheduled shift) from work.

The facility has been asked to provide copies of the site Syngas safety program to other companies involved in coal gasification. Items from the site's program have been incorporated into safety programs of other gasification sites.

3.0 Additional Information - Safety

All plant new hires receive a twenty (20) hour safety orientation upon arrival at the site. No new hire may perform work tasks or start department training until completion of the safety orientation. Items covered in the orientation are:

- Issuing of company Safety Rule Book
- Issuing Tracy New Hire Safety Orientation book
- OSHA Rights & Responsibilities
- Accident causes and results
- Hazard Communication
- Drug & Alcohol policy
- Confined Space entry
- Lockout/Tagout
- Respiratory Protection
- Hearing Conservation
- Fall Protection
- Blood Borne Pathogens
- Fire Safety & Extinguisher use
- Accident Reporting Procedures
- Personal Protective Equipment
- Electrical Safe Work Rule
- Syngas Safety
- DOT rail car rules
- Bomb Threat procedures.

In addition, all new hires must view a motivational safety video titled "Remember Charlie". All employees, except for the most recent new hires, are current with First Aid and CPR training and certification.

All plant visitors and contractors receive safety orientation upon initial arrival at the site. Individuals that are not expected to perform work tasks receive a basic orientation of hazards and expectations. These persons must be accompanied by a plant escort at all times. Examples would be inspectors, those interested in tours, salesman and certain consultants. Those that will be performing work tasks are presented with a much more extensive contractor based safety orientation. Samples of these programs are included in Appendix A of this Section.

- From 1996 to date the Tracy/Pinon facility has maintained low OSHA Incident Rates maintaining ranking within the top quartile of Sierra Pacific Resources (SPR).

- Plant incident rates continue to be much lower than the national industry average.

- For the year 2000, the Tracy/Pinon facility is the only SPR generating station with an Incident Rate of zero (0.00).

- From 1996, to date, one lost time accident has been attributed to the Pinon project. Time off was required from an employee receiving a hematoma in the knee from crawling on piping.

- Up until that time, July 1997, the facility had achieved seven hundred four (704) consecutive days without a lost time accident.

- From the above mentioned date, to March 21, 1999, the facility achieved six hundred (600) days without a lost time accident. The accident of March 21, 1999 was not related to the Pinon operation.

- Since then, as of the start of this report (September 27, 2000), the facility has not incurred a lost time accident.

Reporting of all accidents, incidents and near misses is strongly encouraged. All events, including near misses, are investigated. Accident investigation at the facility is based on Root Cause Analysis. Root Cause Analysis is designed to uncover all contributing factors to an accident. This could be behavioral, engineering/equipment design, procedures or training. Once Root Cause has been established proper actions can be taken to avoid a recurrence of the same or similar event. Accident investigation philosophy at the Tracy/Pinon facility has been adopted by other departments and divisions of SPCo. All contractors and visitors are also strongly encouraged to report any accidents, incidents or near misses.

The facility has an active Safety Committee. Currently, there are four (4) members. This is one more than recommended by the company and the bargaining unit contract. The Committee performs safety audits of the facility at least twice a year. This Committee has also written and adopted their own Charter.

The site Safety Consultant maintains a good working relationship with regulatory and emergency response agencies. The Nevada OSHA Consultation division has performed accident investigation training for plant employees at the request of the Safety Consultant. The Safety Consultant has shared lesson plans with the Nevada OSHA Consultation office to share with other groups. Communication is maintained with the local fire and medical response agency. Shortly after new transfers arrive at the closest fire station they visit the site for safety orientations, instruction and tours. Other local emergency response groups also receive site safety training and orientation tours of the facility. The last DOT compliance inspection resulted in a complimentary letter being received from the two inspectors. This facility has yet to receive an OSHA violation/compliance citation.

In 1997, a plant Rescue Team was formed. This group received initial forty (40) hour training from the State of Nevada. The primary purpose is to provide rescue capability in the event of a confined space emergency. In the near future, additional rescue support will be provided by the local fire protection agency.

Due to the unique nature of the Pinon project, a committee was formed to create and institute safety procedures and policies pertaining to the project. This committee started meeting in February of 1997. Meetings continued until mid April of that year. Committee members consisted of the SPPCo Pinon Production Manager, SPPCo Pinon Construction Manager, a representative from DOE, a representative of Kellogg, a Foster Wheeler representative and the SPR site Safety Consultant. The committee was chosen for the diverse backgrounds & professional disciplines represented.

In early March of 1997, it was agreed that the site Safety Consultant would visit another site involved with coal gasification. The purpose was to learn what safety programs and policies others had enacted that could be adopted for the Pinon project. The Polk Power Station operated by Tampa Electric Company was chosen for this visit because they had entered into their gasification start-up phases

At the Polk site, the Tracy/Pinon Safety consultant met with various staff including environmental/safety, operations, maintenance, engineering and the contractor. A review of their process and all existing written safety programs and policies was made. Some things examined were complete enough to warrant obtaining for possible inclusion in the procedures being written for the Pinon process. Others were either incomplete or not available. Items obtained for future use were the Response Plan, the Material Safety Data Sheet provided to Polk by Texaco and some plume release data. Upon his return to Tracy/Pinon, the Safety Consultant sent the Tracy Contractor Safety Orientation Program to the Polk environmental/safety person for his future use.

Pinon safety policies and procedures were published in April 1997. Safety Policy/Procedures prepared covered General Safety Hazards, Normal Operation, Abnormal/Emergency Procedures, Visitor/Vendor Control and a Syngas Material Safety Data Sheet. These items are included as part of Appendix A of this Section. Additional addendums or memos relating to these items have been issued on a periodic basis.

Upon completion of the original policies and procedures, all plant employees received classroom instruction covering all items. In addition, all on-site contract personnel and any other individuals that may require access to the process or may have exposure to the process received the same classroom instruction. As new employees, or other individuals having need to be near the Syngas areas have arrived on-site they have received this same training before being released for work duties. To date, three hundred twenty-five (325) individuals have received Syngas Safety Training. This figure includes members of local emergency response groups, as mentioned above. This training takes an average of one and a half (1 ½) to two (2) hours.

During 1996 and early 1997, various items were purchased to improve the safety of plant personnel involved with the project. Some of these items were four gas personal monitors, self-contained breathing apparatus, five minute escape masks, fall protection devices and a variety of ladders. Industrial wagons have also been purchased to minimize potential injuries to plant personnel.

Early in 1998, Radian International was commissioned to perform a toxic release plume study to estimate potential downwind concentrations of toxic chemicals in the event of a Syngas release. Four separate release sites were chosen. They were the Gasifier, booster compressor, cooled recycle gas compressor and the product gas line connecting to the Syngas Module. Radian was asked to estimate impact concentrations at the Control Room and the Unit #4 stack (stack platform for CEM maintenance). Release impacts were modeled for Carbon Monoxide, Ammonia, Hydrogen Sulfide, Sulfur Dioxide and Carbonyl Sulfide. Table 1 lists established exposure allowances for these chemicals.

Radian was provided process flow data, Syngas composition, heat balance data, past historical meteorological information, site and structure elevations. They also visited the site, toured the Syngas areas and met with process engineers to gain additional needed data. All Radian release scenarios were based on what is believed to be the most plausible worst case, (this includes weather patterns that would lend itself towards a worst case event). The worst case scenarios assumed a 100% run/production rate. It was assumed that 10% of the total process flow was released from the Gasifier, Recycle Gas & Booster Compressors (Scenarios 1,2 & 3). For the scenario related to an excursion near the Syngas Module (Scenario #4), 2.3% of the flow was released.

The tables that follow show the results of the plume study performed by Radian. Table 2 denotes the source parameters. Table 3 denotes the anticipated worst case release rates. Tables 4, 5, 6, & 7 reflect anticipated impacts based on these scenarios. The expectations of any released gases rising or dispersing to minimize employee exposure were confirmed. The only concentrations of note were for an one hour release from either the cooled recycled gas compressor or the booster compressor. This is due to the low gas temperature and the extended leak time of one (1) hour. A one hour release from either the recycled gas compressor or booster compressor is not to be expected due to the presence of the area gas monitors. It is understood that both of these releases would be quickly noted and easily stopped before reaching this time frame. The existing sensors alarming at the Distributed Control System (DCS) allow this quick reaction to take place.

To better understand the modeled impact concentrations, a few definitions and listings are provided:

Permissible Exposure Limit (PEL):
The concentration of a contaminant that an individual may be exposed to continuously over an eight hour period, without the aid of any personal protective equipment. PEL is a value set and enforced by OSHA. Naturally, shorter exposure periods (less than 8 hour) allow this number to be higher, as long as the accumulated exposure does not exceed the 8 hour limitation. ($E=C_aT_a \div 8$)

Immediately Dangerous to Life and Health (IDLH):
Term established by the National Institute for Occupational Safety and Health (NIOSH) As stated in the NIOSH Pocket Guide to Chemical Hazards, "In determining IDLH values, the ability of a worker to escape without loss of life or irreversible health effects was considered along with severe eye or respiratory irritation and other deleterious effects that could prevent escape. As a safety margin, the Standards Completion Program IDLH values were based on the effects that might occur as a consequence of a 30-minute exposure." This value is primarily used to established the need for a supplied air respirator in lieu of an air purifying respirator.

4.0 Emergency Response Planning Guideline (ERPG):
Exposure values established by the American Industrial Hygiene Association. EPRGs are intended to provide estimates of concentration ranges where one reasonably might anticipate observing adverse affects. These are recommendations and are not enforceable values.

ERPG-1 is the maximum airborne concentration below which it is believed that nearly all individuals could be exposed for up to one hour without experiencing more than mild transient adverse health effects or perceiving a clearly defined, objectionable odor.

ERPG-2 is the maximum airborne concentration below which it is believed that nearly all individuals could be exposed for up to one hour without experiencing or developing irreversible or other serious health effects or symptoms which could impair an individual's ability to take protective action.

ERPG-3 is the maximum airborne concentration below which it is believed that nearly all individuals could be exposed for up to one hour without experiencing or developing life-threatening health affects.

Table 1
Exposure Limits

Component	PEL	IDLH
CO	50 PPM (OSHA has yet to lower)	1200 PPM
NH_3	50 PPM	300 PPM
H_2S	20 PPM	100 PPM
SO_2	5 PPM	100 PPM
Carbonyl Sulfide	none established	none established

Chemical	ERPG-1	ERPG-2	ERPG-3
CO	200	350	500
NH_3	25	200	1000
H_2S	0.1	30	100
SO_2	0.3	3	15

(No data established for Carbonyl Sulfide. It is noted as eye and skin irritant.)

Table 2
Modeled Syngas Source Parameters

Source Parameter	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Description	Product Gas from Gasifier	Recycle Gas to RG Booster Compressor (C901)	Cooled Recycle Gas (C902)	Product Gas to Gas Turbine (Syngas Module)
Height Above Ground (ft)	100	0	0	20
Temperature (F)	1800	90	270	1000
Water Vapor Fraction	0.05	0.003	0.05	0.05
Air Fraction	0.71	0.74	0.71	0.71

Table 3
Modeled Emission Rates

Chemical	Emission Rate (pounds per hour)			
	Scenario 1	**Scenario 2**	**Scenario 3**	**Scenario 4**
Carbon Monoxide	8,300	144	1,057	1,791
Ammonia	4.0	0.1	0.5	0.87
Hydrogen Sulfide	12.7[a]	0	0.1	0.18
Sulfur Dioxide	24[a]	0	0	0
Carbonyl Sulfide	3.0	0	0	0

[a] Scenario 1 accounts for the possibility of Syngas autoignition. In this case, all hydrogen sulfide converts to sulfur dioxide. These two chemicals would not be present at the same time.

Table 4

Scenario 1 Results – Product Gas from Gasifier

Chemical	Maximum Average Concentration at Control Room (ppm)			Maximum Average Concentration at Stack Platform for CEM Maintenance (ppm)		
	4 Hour Release	1 Hour Release	10 Minute Release[a]	4 Hour Release	1 Hour Release	10 Minute Release[a]
Carbon Monoxide	0	0	0	0	0	0
Ammonia	0	0	0	0	0	0
Hydrogen Sulfide	0	0	0	0	0	0
Sulfur Dioxide	0	0	0	0	0	0
Carbonyl Sulfide	0	0	0	0	0	0

[a] No impacts were found at either receptor for the 3 – minute modeled release

Note – The exposure duration is approximately equal to the release time

Table 5

Scenario 2 Results – Recycle Gas to RG Booster Compressor

Chemical	Maximum Average Concentration at Control Room (ppm)			Maximum Average Concentration at Stack Platform for CEM Maintenance (ppm)		
	1 Hour Release	10 Minute Release	3 Minute Release	1 Hour Release	10 Minute Release	3 Minute Release
Carbon Monoxide	122	76	20	10	5	< 1
Ammonia	<1	<1	<1	<1	<1	<1
Hydrogen Sulfide[a]	–	–	–	–	–	–
Sulfur Dioxide[a]	–	–	–	–	–	–
Carbonyl Sulfide[a]	–	–	–	–	–	–

[a] This chemical is not present in the released gas.

Note – The exposure duration is approximately equal to the release time.

Table 6

Scenario 3 Results – Cooled Recycle Gas

Chemical	Maximum Average Concentration at Control Room (ppm)			Maximum Average Concentration at Stack Platform for CEM Maintenance (ppm)		
	1 Hour Release	10 Minute Release	3 Minute Release	1 Hour Release	10 Minute Release	3 Minute Release
Carbon Monoxide	565	398	0	62	35	0
Ammonia	1	<1	<1	10	6	<1
Hydrogen Sulfide[a]	0.4	0.2	0.01	0.5	0.1	0
Sulfur Dioxide[a]	–	–	–	–	–	–
Carbonyl Sulfide[a]	–	–	–	–	–	–

[a] This chemical is not present in the released gas.

Note – The exposure duration is approximately equal to the release time.

Table 7

Scenario 4 Results – Product Gas to Gas Turbine (Syngas Module)

Chemical	Maximum Average Concentration at Control Room (ppm)			Maximum Average Concentration at Stack Platform for CEM Maintenance (ppm)		
	1 Hour Release	10 Minute Release	3 Minute Release	1 Hour Release	10 Minute Release	3 Minute Release
Carbon Monoxide	0	0	0	0	0	0
Ammonia	0	0	0	0	0	0
Hydrogen Sulfide[a]	0	0	0	0	0	0
Sulfur Dioxide[a]	–	–	–	–	–	–
Carbonyl Sulfide[a]	–	–	–	–	–	–

[a] This chemical is not present in the released gas.

Note – The exposure duration is approximately equal to the release time. Safety related concerns have delayed some start-ups of the Gasifier. Other items or events also had the potential to impact the safety of plant personnel. The most significant are also discussed in other Sections of the Final Technical Report. Some of these items are as follows:

- Guarding on the conveyor systems was found to be deficient and non-compliant during turn-over from construction. Additional personnel guarding was installed along different coal conveyors. Full cages were also installed surrounding the take-up pulleys of two conveyor systems.

- The original design for the toxic gas alarm system was found to be inadequate. Design called for each of three gases monitored (CO, H_2S and SO_2) to have its own significant audible alarm. In addition, color coded strobe lighting was to be associated with each alarm.

Problems noted are as follows:

1. Alarm tones could not be heard over the noise created by process equipment.

2. Many lights were placed in positions that made them difficult to see. (It should be noted that the problem of seeing the strobe lights has also been experienced at the TECO Polk site.)

3. The Control Room had no true indication of which toxic gas sensor had gone into alarm state. An alarm was indicated, but location was not.

   The following solutions to these problems were reached:

1. All three alarms were tied into a "common" alarm.

2. Additional "Gaitronics" alarm/paging speakers were added throughout the Gasifier structure and nearby areas.

3. Changes were made to the distributive control system logic to indicate to the Control Room Operator which sensor had gone into an alarm state.

4. It was agreed that the new audible alarms in addition to radio contact from the Control Room would provide adequate protection for plant personnel. Hence, existing strobe lights were not moved or altered.

   - Pressure vessels and bins were found to have rupture plates/discs that were orientated toward personnel walkways and platforms. Primary concern was the Feed Surge Bin. Normal contents of this vessel are crushed coal and limestone. If a rupture disk released, an individual could be impacted by the liberated dust and fines and the potential of a deflagration. Shields were installed to deflect from personnel. A safety chain was added to one deck to limit access to the western edge over one of the bins.

   - Other pressure vessels on the Gasifier Island were found to be lacking pressure relief devices. This could have resulted in total vessel failure and severe injury to personnel. Appropriate relief devices were installed.

   - Protection from fire in the coal silo did not exist. A constant nitrogen purge was added to minimize spontaneous combustion and facilitate quick extinguishment of any fire.

   - A concern was raised regarding uncombusted fines transfer to the LASH silo. The risk of fire due to the fines, coal and coke breeze, was presented. A nitrogen purge line was installed to this vessel to prevent the chance of spontaneous combustion.

   - The noise level from one air compressor exceeded the OSHA allowable ceiling limit. Insulation was installed to reduce the noise level to allowable decibel levels.

   - The noise level from the flare valves exceeded OSHA allowable limits. Modifications and insulation was added to reduce the noise to an acceptable level.

   - When the coal gasification process is running, ambient noise levels are significant. With the wearing of proper hearing protection, communication between individuals became very difficult. The ability to communicate with the plant radios was greatly minimized. An employee could not hear what was being said on the radio without removing hearing protection and holding the radio speaker to their ear. Special radio headsets were purchased to minimize this problem. The headsets incorporate a voice activated microphone and an insert earpiece that allows wearing an ear muff over it to still protect the wearer from ambient noise levels.

The most significant delay of start-up was the re-design and relocation of the process flare stack. In the spring of 1997, operation testing was conducted on the original flare. Concerns were raised from observations regarding radiant heat and related hazards. An initial radiant heat study was performed and issued by MW Kellogg. This report revealed significant radiant heat hazards. It was agreed that an additional, more concise study was needed. Consensus was the new study should be performed by a third party with minimal vested interest in the original design.

Bechtel, Inc. was commissioned to perform the second radiant heat study. The report from Bechtel was issued in September of 1997. Upon review of the Bechtel report, it was agreed that the existing flare design and location presented unacceptable risks. Projected radiant heat would create a severe safety impact on plant personnel. Some structures and vessels could also experience flame impingement during operation of the flare.

Due to the information received, it was agreed to re-locate and change the design of the flare system. Flare remediation agreed upon was:

- Move the flare to a safer location
- Elevate the flare an additional thirty (30) feet
- Change the flare tip diameter
- Fabricate an assist gas ring to the top of the flare
- Change the purge gas from natural gas to nitrogen
- Relocate the flare relief system purge tie-in point
- Electrically heat trace the relief system purge line.

The new design was subjected to a Management of Change and Process Hazard Analysis (PHA) before final approval. The "What If" methodology was utilized in the review. Represented on the PHA committee were SPR, Bechtel, M.W. Kellogg and Flaregas. Upon approval of the MOC and completion of the PHA, construction of the new flare proceeded. The new design and location enhanced safe operation of the facility.

Another item of note that impacted start-up and operation was a series of coal fires experienced in both 1997 and 1998. The majority of these fires occurred in the coal storage dome. Although there were some coal fires that would be considered significant, no injuries or impacts on employee health was experienced.

An initial inventory of coal had been obtained in anticipation of a 1997 start-up. This inventory was an approximate forty-five (45) to sixty (60) day operating supply. Design of the dome "stacker/reclaimer" resulted in the coal being loosely piled in the storage dome as it was unloaded from rail cars. Because it was piled loosely, spaces between the pieces of coal allow air movement. The design of the stacking system and of the dome does not lend itself to being able to layer the coal in compacted lifts. Room is not available in the dome for equipment to move, compact and "work" the coal inventory.

Due to numerous delays in start-up, the initial coal inventory was idle for a number of months. The coal remained in the loosely piled stacks. This condition resulted in a number of fires created by autoignition. The majority of the fires were of the smoldering variety, emitting quantities of smoke and with few visible flames. On others, notable flame fronts were experienced. All were handled and extinguished by use of equipment to extract the burning coal, compact and cool it.

In May of 1998, the most serious coal fire was experienced. This fire required the services of the local fire agency. Coal that had accumulated at the base of the stacker/reclaimer and in the reclaimer chute was involved. The coal in this area was involved in a complete flame front. The intensity of the fire at this point made it difficult to determine where the base of the flames were located. Other parts of the inventory in the dome were involved, as well. The fire agency was instructed to spray surfactant foam on the flames, followed by a water deluge. Due to prior joint training sessions extinguishing the fire went smoothly.

A special agreement was reached with the Nevada Department of Environmental Protection to remove the coal inventory from the dome. Silt fences, an inventory containment area and other environmental safeguards were installed. The coal was removed from the dome using heavy equipment. As it was deposited in the containment area, the coal was compacted to extinguish burning coal. The coal inventory remains in this temporary containment area and is monitored on a daily basis for potential hot spots. No fires have been experienced since the relocation of the coal inventory.

In January of 1999, a process-upset with the flare occurred. Fines from de-pressurizing the Filter Fines Depressurization Hopper had accumulated in the flare header. The Gasifier bed was slumped and the nitrogen purge system was activated. Fines that had accumulated in the line were carried out of the flare as particulate emissions. The emission was a black cloud resembling soot. This material drifted to the ground presenting a respiratory concern. All employees that were outdoors during the process-upset, or had the need to be, were immediately instructed to use respiratory protection. The requirement stayed in place until particulate matter was no longer observed falling or drifting in personnel breathing zones.

Three grab samples of the soot emitted from the flare were obtained that morning. Analysis were run on an expedited basis at a third party lab. Of the eleven (11) chemicals tested for, only a few resulted in measurable amounts. Based on the lab analysis, and the short duration of the release, it was determined that no allowable or prudent health exposures were exceeded. Lab results are listed on Table 8:

Table 8

Lab results from flare upset

Constituent	**Sample – Soot**		**OSHA PEL**
VOC	**PPB**	**PPM**	
TPH (*)	N	N	Not listed
Freon III	280	0.28	Not listed
Chloroform	98	0.098	50 PPM, Ceiling
111 Trichloroethane	250	0.25	350 PPM
Carbon Tetrachloride	360	0.36	10 PPM
Benzene	3200	3.2	10 PPM
Toluene	N	N	200 PPM
N Butyl Benzene	N	N	Not listed
Hexaclorobutadiene	N	N	0.02 PPM - NIOSH
Napthalene	N	N	10 PPM
Xylene	N	N	100 PPM
Semi Vol, <u>Max</u> method			
Napthalene	23000	23	10 PPM, C 50 PPM
Phenanthrene	N	N	

(*) = Total Petroleum Hydrocarbons **(**) N** = Non-detectable **PPB** – Parts per billion, **PPM** – Parts per million, **PEL** – Permissible Exposure Limit, average allowable exposure over a continuous 8 hour period, Values taken from 29 CFR 1910.1000 Tables Z-1, Z-2, ***Note:*** NIOSH values are recommended guidelines and are not considered mandatory unless referenced by OSHA.

Remedial action was taken by modifications to the Filter Fines Depressurization Filter to minimize the chance of fines being carried over into the flare line.

It was agreed after the flare upset that any future changes would go through a Management of Change (MOC) process. All modifications to the process now incorporate MOCs. This philosophy is also being adopted for other operating areas of the site. A sample of the MOC form is included in Appendix A of this Section.

Safety and other Compliance activities have been reported on a quarterly basis as part of the Quarterly Environmental Report to the Department of Energy.

The following Appendices reflect the Safety Program and training received by employees and contractors. Forms used by team members of the project are also included.

Tracy Power Station
Contractor Safety Requirements & Hazard Training

1. POLICY/PURPOSE

It is the policy of Sierra Pacific Power Company, Tracy Power Station (SPPCo) that all Contractors & other non-company personnel performing work on company property shall comply with all applicable regulatory requirements & the safety and training requirements of SPPCo. The purpose of these guidelines is to protect employees from injury or illness while contract work is being performed; to ensure similar protection for Contractor's employees; and to limit SPPCo.'s liability in its contractual relationship with non-company personnel (contractors, vendors, suppliers, etc.).

2. RESPONSIBILITIES

The responsibility for implementing the policy is assigned to the Contractor's on site representative. The representative, together with SPPCo., will develop safety guidelines for the project or work to be performed. Contractors, however, will be held responsible for the safety of their own employees and for performing work in a manner that meets the requirements of OSHA, EPA, State of Nevada and SPPCO. safety policies.

3. GENERAL INFORMATION

1. CONTACT INFORMATION

Control Room:

Use one of the plant-wide grey intercom phones, press the page button and say "Control Room". Release the button and tell the control room of your request.

Plant Contacts:

Plant Manager:	Brent Higginbotham	834-4672
Administration Team Lead:	Tim Howsley	834-5040
Operations Superintendent:	Terry Butcher	834-4383
Maintenance Superintendent:	Ward Ireland	834-4666
Pinon Production Specialist:	Leo Leighton	834-3516
Controls Specialist:	Eugene Wiedenbeck	834-4673
Plant Engineer:	Brian Lawson	834-3304
Technical Working Foreman:	Kevin Steelman	834-5097
Maintenance Working Foreman:	Bob Warne	834-3039
Environmental Specialist:	Gary Shaw	834-4676
Environmental Engineer/RSO:	Mari Willis	834-5057
Safety Consultant:	Jim Rice	834-3890

Parking:

Unless special arrangements have been made, all construction personnel are required to park in the lot on the North side of the river. No private vehicles are allowed on the plant site or construction area. If it is necessary to visit the plant office area, please park in the parking lot across from the covered parking area. Covered parking is reserved for plant personnel.

Rest rooms:

Contractors supplying ten (10) or more workers on any shift will be required to provide portable rest room facilities for construction personnel. For smaller crews, the most convenient rest rooms are located in the basement (ground floor) of Unit #3, (south east side). Do not use rest rooms in the Control Rooms.

Telephones:

The facility's telephone system is limited; therefore Contractors are asked to refrain from its use, including control rooms and Shift Supervisor's office. Contractors may arrange for their own telephone service to be provided for the project. When available, a list of construction key personnel and telephone numbers shall be supplied to plant management.

Water:

The Contractor will be required to provide drinking water for construction employees. Drinking water at the facility meets the drinking water standards and is considered potable.

Smoking areas:

All buildings and office areas are non-smoking areas. Smoking is permitted outdoors, only. Smoking is prohibited when working with/near, flammable or combustible items or materials. Cigarette butts, etc. will be picked up.

Break room:

Unless special arrangements have been made, the break room (kitchen area) is for plant employees only and off limits to construction personnel.

4. SAFETY GENERAL

Electrical power plants contain certain hazards including chemicals, noise, asbestos, low and high pressure steam, tripping and danger of falling objects. The most common hazardous chemicals on site are sulfuric acid, sodium hydroxide (caustic soda) and solvents. Material Safety Data Sheets for these and other materials on site are available in the main office building. A list of hazardous materials on site is listed in Attachment #1. Many of the pipes at the facility are insulated with asbestos. Should insulation become exposed, please notify the Environmental Specialist and inquire as to its status. Piping may create an additional hazard due to containing steam at elevated temperatures and pressure. Rupturing or breaking of a live steam line could lead to a catastrophic accident.

Ionizing radiation devices (nuclear level gauges) have been installed on the Gasifier Island. These gauges are installed on F-501 and BN-504. F-501 has one nuclear level gauge, and BN-504 has two installed.

Background radiation from such devices is extremely small. Most nuclear gauging devices emit background radiation equivalent to an household smoke detector. The radiation source is contained within a well shielded source holder equipped with a shutter. Care is recommended when working in the immediate proximity of these devices.

NOTE: No Non-Tracy personnel, contractors & vendors may enter a nuclear gauge area without prior approval of the site RSO (Radiation Safety Officer). Monitoring and calculation of exposure for these individuals is required. This function must be performed by the RSO. A log of contractors/visitors that have entered a nuclear gauge area, and calculated exposures will be maintained by the site RSO.

1. Contractors are responsible for protecting the health & safety of their own employees and sub-contractors. Project accident prevention shall be established by the Contractor. All work performed at the Tracy site shall comply with SPPCo., State & Federal Safety & Fire Regulations and Standards. It is the responsibility of Contract supervision to ensure that their employees fully comply with these regulations.

2. For tasks within their area of expertise, Contractors may determine their safety practices and procedures within acceptable industry standards. However, violations of applicable Federal, State, SPPCo, rules and regulations or acceptable industry practices will be brought to the attention of the Contractor for corrective action.

3. Contractors are responsible for filing any and all accident reports required by regulatory agencies and State worker's compensation laws. **Mandatory:** The Contractor is responsible for providing proof of workmen's compensation insurance coverage with the Nevada State Industrial Insurance System or that of a reciprocal agreement state. The Contractor must additionally report to SPPCo. any accidents or injuries occurring on the property.

5. Site Safety

The Contractor shall be responsible for the strict observation by all its employees, of all safety laws, rules, and regulations which may be enforced by OSHA or any other jurisdictional safety agency, and any rules and regulations which may enforced by SPPCo..

Prior to submitting its bid, the Contractor is encouraged to contact the State Industrial Insurance System and OSHA for any special or unusual safety rules that may be enforced.

The Drug Free Workplace Act of 1988 requires that contractors and sub-contractors of Sierra Pacific Resources and its affiliated companies to maintain a workplace free of drugs and alcohol. The unlawful manufacture, distribution, possession or use of a controlled substance or alcohol is prohibited in SPPCo.'s workplace or job site.

Contractors shall be required to remove any of its employees or its sub-contractors employees suspected by contractor or SPPCo.of being under the influence of drugs or alcohol.

COMPLIANCE WITH SAFETY AND HEALTH REGULATIONS, MANDATORY

1. Prior to commencing work, Contractor's representatives will be required to attend a pre-job safety conference with a SPPCo. Safety Specialist, Project Supervisor or Shift Supervisor. At this time, specific areas, policies, hazards related to the job and safety requirements will be addressed.

2. Every employee of the Contractor, subcontractor or any other person performing work on site will receive hazard training from Contractor supervision to familiarize them with the primary hazards related to the work activity and applicable safety regulations. The Contractor is to document that the above information and training has been given to his or her employees.

3. Inspections will be conducted bySPPCo. Safety violations will be abated in a timely manner. SPPCo. retains the right to refuse access to any Contractor, subcontractor, their employees or vendor whose work procedures and/or equipment do not comply with applicable safety and health standards. Contractors with repeated violations may have their contracts voided.

4. If a regulatory citation is received by SPPCo. because of a Contractor's noncompliance with safety regulations, the Contractor may be assessed the cost of the fine and penalties that are incurred because of the citation.

6. GENERAL SAFETY RULES AND PROCEDURES, MANDATORY

1. Contractor's activities and work is to be coordinated with the company representative for that area. Contractor's employees will confine themselves to those areas where contractor's work is being performed, and designated break areas.

2. Any work deemed hazardous by SPPCo. or the Contractor will be stopped immediately and fully investigated before work resumes. Any hazards presented by the Contractor's work or noticed by the Contractor is to be reported to the SPPCo. representative. This is to include any chemical spills, including fuels.

3. In the event of an emergency, Contractor personnel shall notify the main Control Room, using radio, telephone, or Gaitronics and shall give the following information: Name, location and nature of the emergency. The Control Room will then initiate SPPCo's emergency procedures. Contractor personnel shall not initiate any emergency notifications of emergency service (EMS, fire departments, etc.).

4. Hard hats and ANSI approved safety glasses will be worn at all times on the job, with the exception of lavatories, lunch rooms and office areas. Appropriate footwear shall be worn (i.e., good leather work boots). Tennis shoes, open toed shoes, sandals or canvas shoes are **NOT** considered appropriate footwear. Gloves shall be worn as needed. Appropriate personal clothing must also be worn Tank tops, sleeveless shirts and short pants will not be allowed.

5. Hearing protection will be worn in high noise areas or around equipment which produces high noise levels, or where posted.

6. All work areas will be maintained in an orderly manner. Waste materials shall be placed in appropriate containers.

7. In the event of an accident or injury, the contractor will notify the Sierra representative immediately. Records shall be kept of all accidents, injuries and near misses, and provided to the SPPCo. representative.

8. A Material Safety Data Sheet must accompany all chemicals to be used on the plant site. No chemical shall be off loaded on the plant site until the appropriate MSDS has been delivered to the Safety Specialist or Shift Supervisor. It is the Contractor's responsibility to dispose properly of all chemicals and their by-products as per State and Federal regulations. It is also the responsibility of the Contractor to assure that all containers are labeled in accordance with DOT, NFPA 704 and/or 29 CFR 1910.1200 Standards.

9. The use of respiratory protection is required when sandblasting, painting, handling hazardous chemicals or when required in accordance with 29 CFR 1910.134. All personnel wearing respiratory protection shall be clean shaven where the sealing surfaces of the respiratory protective device contacts the body.

10. Electrical tools must be grounded properly or double insulated.

11. All electrical installations must comply with National Electrical Code.

12. Mechanical safeguards shall be maintained on all moving parts, drive belts, etc.

13. Plant speed limit is **10 miles per hour**. Seat belts shall be worn at all times in vehicles so equipped. There shall be no more riders in or on the vehicle than it is designed to seat. Pedestrians have the right of way at all times.

14. All Contractor personnel working at heights more than six feet (6') above the working surface or grade shall wear and use personal fall protection equipment. This shall consist of ANSI approved harnesses and lanyards at a minimum. The use of belts for fall protection is prohibited. Fall protection will be worn when using powered manlifts (boom trucks, snorkel lifts, forklifts, etc.) and when working on scaffolding and platforms that do not meet the minimum OSHA requirements for walking and working surfaces.

15. All potential hazards must be appropriately marked or barricaded (i.e. overhead work, trenches, etc.) in accordance with Sierra and OSHA Standards.

16. All posted warning signs are to be adhered to (i.e. No Smoking, etc.).

17. No conductive ladders are allowed on the plant site.

18. No switching or valving of plant equipment is to be performed by a Contractor unless under the direct supervision and presence of a qualified Sierra employee.

19. No Contractor shall operate any SPPCo. equipment such as cranes or forklifts unless they have received training and approval from an authorized Sierra employee.

20. All plant lockout/tagout procedures shall be followed. Contractor personnel are **NOT** authorized to hang or remove tags. No tagged equipment is to be operated by Contractor personnel. Tagging clearances shall be coordinated with the Shift Supervisor. (Contractor employees may add their own lock to the SPPCO> lockout. However the lockout/tagout will be under the sole control of the SPPCo. Shift Supervisor.)

    Whenever any of the nuclear level gauges are part of a Clearance, the RSO is to be notified.

21. Contractors may be required to provide, upon request, proof of the following employee training:

    Respiratory protection, Lockout/Tagout, Confined space, Hazard communication, Fall protection, Electrical safety-related work practices, Personal protective equipment.

22. Use of the fire systems and related equipment is restricted to the fighting of fires. The fire system shall not be used for flushing or cleaning without the express permission of the Plant Manager or Safety Specialist. Contractors gaining permission shall return the equipment in the condition it was found.

23. Do not use compressed air to clean off clothing, work bench or floor area.

7. CONFINED SPACE AND HOT WORK REQUIREMENTS

1. Confined space:

    a. SPPCo. contains both permit and non-permit required confined spaces and entry is allowed only through compliance of a permit space program meeting the requirements of SPPCo. and 29 CFR 1910.146.

    b. The Contractor will meet with designated SPPCo. personnel and gain all available information regarding the hazards present and entry procedures.

    c. Entry to spaces will be coordinated between the Contractor and the SPPCo.Shift Supervisor and SPPCo. personnel.

d. The Contractor will inform SPPCo personnel his/her understanding of the permit space entry and methods that will be used to comply.

e. The Contractor will inform SPPCo personnel of any hazards confronted or created during a debriefing after the entry.

f. Contractors shall provide their own attendants and monitoring equipment for the confined space work.

g. Any entry to vessels F-501 and BN-504 will require notification of the RSO, plus closing and locking of the shutter devices before entry can be approved. Under no circumstances may **any** individual enter these vessels unless the shutters have been closed and locked in the closed position. Closing and locking of the shutters is to be verified by the RSO before entry to either of these vessels.

2. Hot work:

a. Contractors will obtain from a SPPCo representative a "Hot Work or Hazardous Work Permit" for any welding or cutting (outside of the normal shop area) where combustible or flammable materials may be present or in a confined or enclosed space.

b. Contractor will insure the placement of proper barriers to protect others from welding/cutting operations, including weld screens for eye protection.

NOTE: **Although SPPCo requires the use of various personal protective equipment, SPPCo considers the items tools of the trade and will not be responsible to provide such equipment, nor will Sierra be responsible to monitor compliance.**

8. ACTS OF MISCONDUCT THAT COULD RESULT IN REMOVAL FROM SITE

1. Violation of any company, State or Federal safety regulations.

2. Failure to report to supervisor and to Sierra any personal accident or injury occurring on shift as soon as possible.

3. Stealing, destroying or defacing property belonging to Sierra or its employees.

4. Unauthorized possession of weapons or explosives on company property.

5. Knowingly possessing, using, transmitting or being under the influence of any narcotic or hallucinogenic drug, amphetamine, barbiturate, marijuana, alcoholic beverage, chemical or intoxicant of any kind while on company property. Appropriate use of a drug prescribed by a medical doctor is not considered an Act of Misconduct.

6. Inciting trouble, attempting bodily injury, using abusive language, horseplay or any other disturbance that may endanger the safety or disrupt the efficiency of other employees.

7. Sexual harassment, including creating an intimidating, hostile or offensive work environment because of unwelcome or unwanted sexually oriented conversations, suggestions, requests, demands, physical contacts or attention.

8. Reporting false information concerning any accident.

SAFETY CHECK-OFF COVERING
CONTRACTOR SAFETY REQUIREMENTS

		YES	NO	N/A
1.	Has Contractor met with company representative to discuss safety requirements?			
2.	Has hazard training been provided to the Contractor?			
3.	Is Contractor familiar with the company's accident & injury reporting requirements?			
4.	Does the Contractor have a safety & training plan covering the project?			
5.	Does the Contractor have an understanding of the confined space entry requirements?			
6.	Does the Contractor have an understanding of the Hot Work Permit requirements?			
7.	Does the Contractor require any special training?			
8.	Does the Contractor have a method of providing and documenting hazard & process training to his/her employees?			
9.	Has the Contractor received and fully understands a copy of Sierra's Contractor Safety Requirements & Hazard Training?			
10.	Has Contractor been apprised of the location of MSDS sheets, safety showers/eye washes & other related items?			
11.	Has the contractor been advised of & acknowledges the presence of ionizing radiation devices on site?			

I HAVE READ, UNDERSTOOD AND AGREE TO COMPLY WITH THE SPPCo CONTRACTOR SAFETY REQUIREMENTS & HAZARD TRAINING.

NAME:_________________________ **SIGNATURE:**______________________________
(Supervisor/Foreman, Please Print)
COMPANY:____ **DATE:**______________

DESCRIPTION OF JOB:
____
____

SPPCo REPRESENTATIVE: ___________________________ **DATE:**_______________
(Contractor to receive copy of "Contractor Safety Requirements". Signature page to be filed in main office.)

Tracy Power Station
Visitor Safety and Hazard Training: Non-Contractor/Non-Job Task Related

POLICY/PURPOSE

It is the policy of the Tracy Power Station that all visitors comply with all applicable regulatory requirements & the safety requirements of Sierra Pacific Power Company. The purpose of these guidelines is to protect visitors and employees from injury or illness while at the Tracy Power Station.

GENERAL HAZARDS

Electrical power plants contain certain hazards including chemicals, noise, asbestos, low and high pressure steam, low and high voltage electricity, tripping and danger of falling objects. The most common hazardous chemicals on site are sulfuric acid, sodium hydroxide (caustic soda) and solvents. Material Safety Data Sheets for the chemicals on site are available in the main office building. Many pipes at the facility are insulated with asbestos. Piping may create an additional hazard due to containing steam at elevated temperatures and pressure. Rupturing or breaking of a live steam line could lead to a catastrophic accident. Ionizing radiation devices (nuclear level gauges) are installed on the Gasifier Island. Be aware of mobile equipment.

GENERAL SAFETY REQUIREMENTS

1. All plant visitors are to have a Tracy employee escort at all times. Please comply with your escort's directions. They are there to insure your safety. In the event of an emergency, follow the directions of your escort.

2. Hard hats and ANSI approved safety glasses will be worn in all areas, with the exception of lavatories, lunch rooms and administrative areas. Appropriate leather footwear shall be worn. Tennis shoes, open toed shoes or sandals are not considered appropriate footwear. Tank tops, sleeveless shirts and short pants are not allowed.

3. Hearing protection will be worn in high noise areas or where posted.

4. Plant speed limit is **10 miles per hour**. Seat belts shall be worn at all times in vehicles so equipped.

5. All posted warning signs are to be adhered to (i.e. No Smoking, Restricted Access, etc.).

6. **All buildings and office areas are non-smoking areas. Smoking is permitted outdoors, only. Smoking is prohibited when near, flammable or combustible items. Food & beverages are permissible only in designated areas. No alcoholic beverages, weapons or non-prescription drugs are allowed on site.**

7. **Exercise caution at all times around equipment. Remain a safe distance from electrical equipment and conveyor belts.**

I have read, understood and agree to comply with the above rules.

Name ______________________________**Signature**________________________
Date________________________ **Organization**____________________________
(Please Print)

Pinon Pine

Coal Gasification/Syngas Safety Procedures
General Hazards

1. PURPOSE:

As with all processes, the Coal Gasification system and the related Syngas Combustion Turbine present various hazards. Although concerted efforts have been made to provide a safe operation, all employees need to be aware of specific hazards. The intent is to provide education of these hazards, aiding the employee's ability to work around and with them in a safe manner. This document is not intended to be a substitute for information gained from an available MSDS for any chemical.

2. SPECIFIC HAZARDS:

A. Heat exposure:

Process piping and vessels will be at elevated temperatures. Skin temperatures of Gasifier piping and vessels can reach 350º F. Although insulated, skin temperature of the Syngas piping to and at the Combustion Turbine Syngas Module will also be at elevated temperatures. Caution is to be used to avoid contact with any of the process piping or related vessels during plant operation.

Where feasible, barriers will be installed to warn and protect personnel from contact with hot surfaces. However, space constraints and the maintenance of walkways & escape ways prevents the installation of barriers at all hot surface areas. Long sleeve flame resistant clothing such as cotton shirts, wool shirts, or other long sleeve flame resistant outer wear is required. The use of leather or cotton gloves is recommended.

B. Noise exposure:

Noise levels on & near the Gasifier island, combustion turbine, steam turbine, coal crusher and the HRSG are anticipated to be elevated. The use of hearing protection is required when in these areas.

C. Discharge of solids, Fire:

The coal/limestone hopper BN-301 and filter F-301 contain pressure rupture disks. Failure of one of these disks could result in the sudden release of pressure, solids and presents the possibility of extremely rapid ignition of the solids. Given an ignition source, coal dust may ignite in an extremely rapid manner. The resultant ignition is considered explosive in nature. Care should be taken to avoid working or traveling in the vicinity of any of the rupture disks.
Additional care should be taken if on the top third section of the coal conveyor to the Gasifier island. A possibility exists of solids discharged from the BN-301 rupture disks impacting the stairway. A source of ignition could transport a flame front to the conveyor stairway.

When working on the platform level above F-301, remain at least ten (10) feet from the west edge of the platform. Any release from the F-301 rupture disk could discharge fines and a resultant flame front into this area.

(NOTE: During operation, barriers will be installed at the access to the conveyor stairs from the silos, and at points near F-301 and BN-301. These barriers are not to be crossed during plant operation.)

Care is to be taken when drawing a char fine sample. Fines samples drawn from BN-507 can be at a temperature of 500° F. Fines at this temperature present a burn and fire hazard. Samples should be allowed to cool to at least 150° F before handling and exposing to the atmosphere. Care should be taken to avoid any spillage and skin contact.

(NOTE: As coal dust and char fines are readily ignitable and also pose a known respiratory hazard, any spillage must be cleaned up immediately. Good housekeeping is a requirement and can not be over stressed.)

D. Discharge of solids, Respiratory:

Limestone:

Although limestone is not considered a toxin, it does create a respiratory hazard. Respiratory protection (dust/mist or HEPA) is to be worn whenever exposed to and handling limestone.

Coal/Coke:

Coal & coke dusts present respiratory hazards. Respiratory protection (dust/mist or HEPA) is required when cleaning up any spillage of coal or coke.

Char:

Char fines present a respiratory hazard due to the extremely small particle size. Respiratory protection (HEPA) is required when exposed to Char.

Z-Sorb:

Z-Sorb is recognized as a respiratory hazard. Z-Sorb contains nickel oxide, considered to be a carcinogen. Respiratory protection (HEPA) is required.

LASH:

Lash is known to present a respiratory hazard. Respiratory protection (dust/mist or HEPA) is required when working with or around exposed LASH.

E. Discharge of solids, Skin:

Limestone:

Limestone is a known skin and eye irritant. Use of Tyvek coveralls, gloves and goggles is recommended.

Z-Sorb:

Z-Sorb presents skin and eye irritation hazards. Use of Tyvek coveralls, (elastic sleeves, legs & hood), gloves and chemical goggles is required.

LASH:

LASH may present a skin irritation hazard. Use of Tyvek coveralls (elastic sleeves, legs & hood), gloves and goggles is recommended.

F. Flammable/Toxic gases:

Flammable and toxic gases are normal components of Syngas. The primary potential for exposure exists around flanges, valve packing and rotating equipment such as compressors.
Refractory lined Syngas piping and vessels on the Gasifier island has been covered with a heat sensitive paint. Any discoloration should be noted and reported to the Control Room immediately. Discoloration can be an early indication of failure of the protective refractory lining.

Hydrogen sulfide, carbon monoxide and sulfur dioxide sensors are present on the Gasifier Island. These are situated near key flange connection areas that pose the most likely chance of leaking. Alarm horns and lights are coupled with the sensors. Warning light indication is as follows:

H_2S	Red
CO	Blue
SO_2	Yellow

As an added measure of protection all personnel in the Syngas Areas will be equipped with four (4) gas monitors (O_2, CO, LEL & H_2S). Periodic monitoring should also be taken around flanges, valves and compressors to allow early detection of any leakage. Sensor extensions and pumps are available for this testing.

In a shut down condition, rapid cooling and failure to purge Syngas with nitrogen has the potential for the formation of Nickel Carbonyl in the Desulfurizer. Allowing the Desulfurizer to cool without/prior to nitrogen purging is a violation of normal established shut down procedures. Therefore, the likelihood of forming Nickel Carbonyl is considered low.

Auto ignition of leaking gases is a possibility. However, experiences at similar facilities have shown this to be a remote possibility. Incipient fire protection equipment is installed on all levels. This includes both ABC rated fire extinguishers and fire hose stations.

G. Ionizing Radiation:

Three ionizing radiation devices (nuclear level gauges) have been installed on the Gasifier Island. These gauges are installed on F-501 and BN-504. F-501 has one nuclear level gauge, and BN-504 required the installation of two.

Background radiation from such devices is extremely small. Most nuclear gauging devices emit background radiation equivalent to an household smoke detector. The radiation source is contained within a well shielded source holder equipped with a shutter. Care is recommended when working in the immediate proximity of these devices.

The nuclear gauges will be monitored for proper shielding and background radiation by a site Radiation Safety Officer (RSO). This RSO is certified/authorized by the State of Nevada for such duties. The site RSO is Mari Willis. At a future date, an back-up/alternate RSO will be named.

Basic hazard training regarding these devices will be provided by the site RSO. General requirements regarding regulations covering working with and around such devices will also be covered.

3. GENERAL HAZARDS:

The following table lists chemicals that may be present in the gas streams and their related hazards. This is for reference only. For specifics, please refer to the individual MSDS.

CHEMICAL	HAZARDS
Coal	Respiratory, Fire
Limestone	Respiratory, Skin, Eye
N_2	Oxygen displacement
A_r	Oxygen displacement
CO	Toxic, Fire, Oxygen displacement
H_2	Fire, Oxygen displacement
CO_2	Oxygen displacement, toxic
O_2	Supports combustion
NH_3	Respiratory, Skin, Eye,
CH_4	Oxygen displacement, Fire
H_2S	Toxic, Respiratory, Fire
SO_2	Toxic, Respiratory, Fire
Steam	Thermal
COS	Toxic, Respiratory
C_aS	Toxic, Corrosive, Respiratory, Skin, Eye
C_aSO_4	Toxic, Respiratory, Skin, Eye
C_aO	Toxic, Respiratory, Skin, Eye
M_gO	Respiratory
LASH	Toxic, Respiratory, Skin, Eye
Ash	Respiratory
Char	Respiratory, Fire
Z-Sorb	Toxic, Respiratory, Skin, Eye, Carcinogen
HTF UCON-500	Respiratory, Skin, Eye
Nickel Carbonyl	Toxic, Respiratory, Skin, Eye, Carcinogen

Pinon Pine
Coal Gasification/Syngas Safety Procedures

Normal Operating Conditions

The following will apply for all tasks that require entry into or onto the Coal Gasification/Syngas areas **(Syngas Areas)**. These requirements pertain to normal start up and operating conditions. Process upset conditions, failure of Syngas containment vessels/piping and work performed after shut down & purging are covered in a separate procedure.

For definition of boundary areas and procedures relating to reagent/feed stock delivery, salespeople and other visitors refer to, "Coal Gasification/Syngas Safety Procedures, Vendors/Visitors."

1. DEFINITION:

The Coal Gasification/Syngas boundary areas **(Syngas Areas)** are defined as:

AREA 1: All items contained within the concrete pad surrounding the coal gasification unit, including the compressor units and other ancillary structures within the concrete pad. Excluding the Analyzer House. **(*See Section 3a Analyzer House Entry*.)**

AREA 2: All items contained within a ten (10) foot radius of the Combustion Turbine Syngas Module; a ten (10) foot radius from adjacent Syngas transport piping installed below a height of fifteen (15) feet above grade; the east side of the Lube Oil Module within ten (10) feet of the Syngas transport piping going from the Syngas Module to the turbine compartment.

(NOTE: As deemed necessary and prudent, boundary areas may be expanded due to certain operational or maintenance tasks. See "Boundary Expansion".)

2. Personal Protection Equipment

In addition to ANSI approved hard hats and safety glasses, the following items will be required of all employees, contractors, & authorized visitors to enter the Syngas Areas.

A. Clothing:

Due to elevated skin temperatures of various vessels and piping (avg. 250 - 350° F) and potential risks associated with working on or around equipment, piping and vessels where Syngas is present, long sleeve flame resistant clothing such as cotton shirts, wool shirts or other long sleeve flame resistant outer wear will be mandatory. Leather, cotton or wool gloves are also recommended.

B. Escape Masks:

1. General:

All personnel entering the Syngas Areas will be required to carry a five (5) minute escape mask. Five minute escape masks will be stored in the Unit #4 Control Room. The Shift Supervisor or Control Room Operator will issue an escape mask to an individual prior to them leaving for the Syngas Areas.

Issuance and return of five minute escape masks will be tracked via a log (Appendix A) kept in the control room. No individual may obtain a mask until entry has been made in the log sheet. Five minute escape masks will be returned to the Control Room immediately after an individual has exited the Syngas Areas. (***Note: No individual may return a mask to the Control Room for another person. Each mask must be returned by the individual it was issued to.***)

It is the responsibility of the Shift Supervisor to insure that any and all entrants have an adequate understanding of the proper use of the five minute escape masks. If needed, training in the use of this item will be provided by the Shift Supervisor.

2. Operations:

Operators assigned to Pinon, and whose duties require them to enter the Syngas Areas on a regular basis, will check out a five minute escape mask at the start of their assigned shift. The operator will retain the same mask throughout their shift. The mask will be checked back in to the Control Room at the end of the operator's shift, just prior to or during shift relief.

C. Hazardous/Toxic Gas Detectors:

1. General:

All personnel entering the Syngas Areas will be required to carry a four gas toxic/hazardous gas detection device (Biosystems PhD Plus). As with above, the gas detection devices will be stored and issued from the Control Room. Gas detection devices will be issued by either the Shift Supervisor or the Control Room Operator.

If entry is for a group of individuals, and it is confirmed that all members of the group will remain in close proximity to each other, issuance of one gas detection device per pair of individuals (i.e. 2 people = 1 detection device) will be sufficient.

Issuance and return of gas detector will be tracked via a log (Appendix A) kept in the control room. No individual may obtain a detection device until entry has been made in the log sheet. Hazardous/Toxic gas detectors will be returned to the Control Room immediately after an individual has exited the Syngas Areas**.** (***Note: No individual may return a detection device to the Control Room for another person. Each device must be returned by the individual it was issued to.***)

It is the responsibility of the Shift Supervisor to insure that any and all entrants have an adequate understanding of the proper use of the gas detection device. If needed, training in the use of this item will be provided by the Shift Supervisor.

2. Operations:

Operators assigned to Pinon, and whose duties require them to enter the Syngas Areas on a regular basis, will check out a portable gas detector at the start of their assigned shift. The operator will retain the same gas detector throughout their shift. The gas detector will be checked back in to the Control Room at the end of the operator's shift, just prior to or during shift relief.

D. Communication - Portable Radios:

1. General:

All personnel entering the Syngas Areas will be required to carry a portable radio. The radios will be stored and issued from the Control Room. Radios to be used in the Syngas Areas will be issued by either the Shift Supervisor or the Control Room Operator. Radios used in the Syngas Areas will be tuned to channel #3. This channel will be monitored by the Control Room at all times.

If entry is for a group of individuals, and it is confirmed that all members of the group will remain in close proximity to each other, issuance of one radio will be sufficient. The radio will be issued to the responsible party leading the group.

(Note: It is each individuals responsibility to insure that the radio is functioning properly before leaving the Control Room.)

Issuance and return of these radios will be tracked via a log (Appendix A) kept in the control room. No individual may obtain a radio until entry has been made in the log sheet. Radios dedicated for the Syngas Areas will be returned to the Control Room immediately after an individual has exited the Syngas Areas**. (*Note: No individual may return a radio to the Control Room for another person. Each radio must be returned by the individual it was issued to.*)**

It is the responsibility of the Shift Supervisor to insure that any and all entrants have an adequate understanding of the proper use of the portable radio. If needed, training in the use of this item will be provided by the Shift Supervisor.

2. Operations:

Operators and other employees assigned to Pinon, and whose duties require them to enter the Syngas Areas and other Pinon facilities on a regular basis, are issued radios that are considered tools of the trade. Therefore, no formal check out/check in of these radios will be required.

(NOTE: It is understood that Pinon Maintenance sometimes requires the use of Channel #4 to communicate with each other for certain tasks. In the event of an alarm, etc. Maintenance personnel will tune their radios to Channel #3.)

3. Hearing Protection:

All personnel entering the Syngas Areas during operating conditions will wear appropriate hearing protection.

4. Access to Syngas Areas

A. General:

Contractors that have received Syngas Area training may work in the Syngas Areas without having a Syngas Area trained Sierra Pacific employee in the immediate vicinity.

Due to potential exposure to hazardous/toxic gases and fire hazards no smoking, eating, drinking, or chewing of tobacco, etc. will be permitted within the Syngas Areas.

Process piping and vessels will be at elevated temperatures. Not all piping and vessels are equipped with personnel protective barriers. Due care is to be used whenever walking or working near any process piping or vessels.

Any color change of the process piping and vessels in Area 1 is to be noted and reported to the control room immediately.

B. Training:

No individual(s) may enter a Syngas Area without having received prior training regarding the hazards of the Syngas Areas, entry/exit procedures and emergency condition procedures. Training shall be documented and forwarded to the Safety Specialist.

Proof of training will be indicated by affixing a special sticker to the trainee's hard hat. To insure updated training, stickers will be changed on an annual basis.

(NOTE: Any individual(s) observed in a Syngas Area without a proof of training sticker on their hard hat will be removed from the area immediately! See "Compliance".)

C. Entry to Syngas Areas:

1. General:

Prior to going to the Syngas Areas, personnel must check in at the Control Room. Entry will be made in the "Syngas Area Entry Log" (Appendix A), providing name, date, time of day, purpose, area entering and anticipated time to be spent in the Syngas Area.

Check out of a five minute escape mask, gas detector & radio will also be made at this time. Issuance of these items will be by the Shift Supervisor or Control Room Operator and noted in the "Syngas Area Entry Log".

Only upon check in at signing out of the required items will an individual be allowed to proceed to the Syngas Area.

2. Operations:

At the start of their shift, Operators assigned to Pinon and whose duties require them to enter Syngas Areas on a regular basis, will check out the required PPE (mask, gas detector) from the Control Room. Check out of these items will be noted on the "Syngas Area Entry Log". At the end of their shift, these items will be returned and noted on the log.

Upon each time that their duties require them to enter a Syngas Area, the Operator(s) will notify the Control Room via radio. The Control Room will note the entry on the "Operations Syngas Log" (Appendix B).

D. Syngas Area Occupants:

No more than twelve (12) individuals will be allowed to be in a Syngas Area at any given time.

No individual will be allowed to enter, or be in a Syngas Area alone. The "buddy" system will be strictly enforced. Communication of occupants/entrants will be by radio and visual contact. Entrants will maintain visual contact with their "buddy/buddies" at all times. Buddies may be on separate levels of the Gasifier **if** visual contact is maintained.

Communication by Syngas Area occupants will be on a regular basis to insure the well being of all parties.

E. Exit From Syngas Area:

1. General:

Upon leaving the Syngas Area, the entrants shall report immediately to the Control Room. The five minute escape mask, gas detector and radio will be returned to the Shift Supervisor or the Control Room Operator.
Return of these items will be noted on the "Syngas Area Entry Log". The entrant will also sign off as having returned from the unit and returning the protective items worn in the Syngas Area.

Note: Individuals returning from the Syngas Area may not leave the Control Room until return of protective items and log off has taken place. No one may sign another individual out from the Syngas Area.

2. Operations:

Upon each time that an Operator(s) exits a Syngas Area, the Operator(s) will notify the Control Room via radio. The Control Room will note the exit on the "Operations Syngas Log" (Appendix B).

At the end of their shift, Operators assigned to Pinon and whose duties require them to enter Syngas Areas on a regular basis, will return and check in the required PPE (mask, gas detector) to the Control Room. Check in of these items will be noted on the "Syngas Area Entry Log".

4a. Analyzer House Entry:

A. General:

The Analyzer House boundaries are considered to be all items within the separate concrete pad surrounding the Analyzer structure. This includes the calibration gas storage located on the outside walls of the structure.

B. Training:

No individuals may enter the Analyzer House boundaries without having received prior training regarding the hazards of the Syngas Areas, entry/exit procedures and emergency condition procedures. (See Section 3, Part B. Training, and Section 5 Compliance)

C. Entry:

1. General:

Entry to the Analyzer House will only be on an "as needed" basis. Such cases would be calibration of instruments, verification of DCS readings, or inspections.

2. Personal Protective Equipment:

In addition to ANSI approved hard hats and safety glasses, long sleeve flame resistant clothing such as cotton, wool or other flame resistant fabrics will be worn. A portable radio tuned to channel #2 will also be in the entrant's possession.

The use of a five (5) minute escape mask and a portable toxic gas monitor will not be required for entry into this area/structure.

3. Entry:

Prior to entering the Analyzer House area, the employee/individual will notify the Control Room of his/her intent, and approximate time frame expected to be in the area. The Control Room will note the entry on the Operations Syngas Log.

Before entering the Analyzer Building, a visual check will be made of the alarm panel on the south west exterior wall of the building. (***Note: If any alarms indicate a release of hazardous/toxic gases with the building, do not enter. Refer to the Abnormal/ Emergency Conditions Procedure.)***

D. Exit:

Upon completion of the job task and exit of the building/area, the employee/individual will notify the Control Room. The Control Room will note the exit on the Syngas Log.

5. Boundary Expansion:

A. Purpose:

Certain maintenance, operational tasks or events may require the temporary expansion of the established Syngas Areas. Such tasks/events would be ones that presented the possibility of creating a hazard beyond the normal boundary areas. (Example: Maintenance or adjustments on a Syngas compressor on grade level where a potential release could impact the east/west roadway between the Gasifier island and the steam turbine building.)

B. Expansion of Syngas Area:

Any employee or Contractor that recognizes a planned (or unplanned) act or event that may create a temporary hazard beyond the normal established boundaries may request that they be expanded. This request will be made to the Shift Supervisor and the Safety Specialist. The Shift Supervisor and the Safety Specialist will jointly decide if the boundaries need to be expanded. In the absence of the Safety Specialist, this decision will rest solely with the Shift Supervisor.

A Tailboard briefing will be held with all affected employees/contractors to advise of the boundary expansion. This meeting will cover the anticipated/actual hazard, affected areas, anticipated duration, entry/exit control and barrier method to be used to mark off the temporary boundary. Documentation will be made of this meeting and the items discussed. An additional announcement of the boundary expansion may also be required via Gaitronics and radio.

Once an expanded boundary has been established, and the Tailboard meeting has been held, work may proceed in that area per the entry/exit controls.

(*NOTE: No one may enter the expanded boundary area that has not been briefed and complied with the entry/exit controls.)*

Upon completion of the task(s)/event that required the boundary expansion, Syngas Area boundaries may be returned to normal. The decision to return Syngas Area boundaries to the normal state will be made by the Shift Supervisor. An announcement, or other effective means of communication, will be made to all affected employees/contractors advising of the change.

6. Compliance

A. Adherence:

Full compliance is required from the Entrants, Visitors, Vendors, Contractors, Control Room personnel, Shift Supervision, and any other Sierra Pacific Employees.

B. Enforcement:

Any violation of the above will be immediately reported to Management and the Safety Specialist. Failure to comply to the above procedures will result in the following corrective action:
SPPCo. Employees:
Disciplinary action up to, but not excluding termination.
Contractor personnel, Visitors or Vendors:
Dismissal from the job, or removal from the property.

(Appendix A)
OPERATIONS SYNGAS LOG

DATE	NAME	AREA #	ENTRY TIME	EXIT TIME

(Enter today's date, name of Operator entering area, area # entered, time of entry & time of exit.)

(Appendix B)
SYNGAS AREA ENTRY LOG

DATE	TIM E	NAME	PURPOSE	AREA #	LENGTH OF STAY	MASK #	SENSOR #	RADIO #	RETU TIM

(Enter today's date, time of check out, entrant's name, purpose of entry, area # entering, anticipated length of stay, item # of mask, etc., time entrant returns, returning entrant
initials to confirm items returned to Control Room. For the purpose of Operations, leave purpose, area #, length of stay & radio # blank.)

Pinon Pine

Coal Gasification/Syngas Safety Procedures

Abnormal/Emergency Conditions

1. INTRODUCTION:

Although it is the intent of Sierra Pacific Power Company to provide a safe and healthy work environment, it also recognized that the possibility of an abnormal or emergency condition may occur. The following will serve as guidelines for actions to be taken in the event of an abnormal or emergency situation involving Syngas.

The essential features of the actions to be taken are to provide a rapid response with trained personnel and adequate equipment to minimize:

Injury to SPPCo. and Contractor personnel, and any additional persons on site;

loss of property;

and any adverse impact on the environment during any abnormal or emergency occurrence.

2. SCOPE:

Proper response to an emergency or abnormal condition may involve a single action/event, or a combination of actions/events. The objectives of any actions taken are in the following order of importance:

PRIMARY: Saving lives and avoidance of injury.

SECONDARY: Protection of property and preventing damage to the environment.

At no time will this established order of importance be allowed to change.

3. RESPONSE LEVELS:

LEVEL 1:

Defined as when a incident/accident has developed at the power station which can be and is being handled by on site personnel, but has a significant probability of developing into a major incident. A Level 1 condition does not require the immediate assistance by off site personnel or resources.

LEVEL 2:

Defined as when a major incident has occurred and/or additional resources are needed (Fire, Ambulance, Care Flight, Law Enforcement) by on site personnel to handle an incident that may expose personnel, the environment, or off site areas to a significant hazard.

3. DETECTION:

There are four (4) basic sources of detection for 1) gas releases, 2) fires, 3) hazardous spills, 4) injuries, and 5) any catastrophic damage to Sierra facilities. The four (4) basic sources for detection are:

A. Personal Detection-Monitoring Devices:

All personnel entering or working in areas where Syngas may be present, (Syngas Areas) are equipped with a portable four (4) gas monitor. The portable detection devices monitor Oxygen, LEL, Carbon Monoxide and Hydrogen Sulfide. These units are set to provide an alarm at the following levels:

Gas	Ceiling	TWA	STEL
CO	35 PPM (OSHA=200 PPM)	35 PPM	100 PPM
H2S	10 PPM (OSHA=20 PPM)	10 PPM	15 PPM
Oxygen (O2)		Low Alarm: 19.5%	High Alarm: 23.5%
Combustible Gas		10% LEL	

TWA: The maximum average concentration to which an unprotected worker may be exposed over an eight (8) hour working day.

STEL: The maximum average concentration to which an unprotected worker may be exposed in any fifteen (15) minute interval during the day. (During this time, neither the eight hour TWA or the ceiling concentration may be exceeded.)

Ceiling: The highest concentration of a toxic substance to which an unprotected worker should ever be exposed, even for a short time.

B. Permanently Mounted Area Detection-Monitoring Devices:

Local hazardous condition detection devices (toxic substances, fire) are installed at the facility. These devices will provide a local alarm indication and signal the Control Room. Toxic gas monitoring devices are installed on the Gasifier Island.
Local toxic gas monitoring devices are provided to detect Hydrogen Sulfide, Carbon Monoxide and Sulfur Dioxide. The devices include local audio (horns) and visual (light) indication of an alarm condition. These units are set to provide an alarm at the following conditions:

Gas	Alarm Level	OSHA TWA	STEL
CO	**25** PPM	35 PPM	100 PPM
H2S	**10** PPM	10 PPM	15 PPM
SO2	**2** PPM	2 PPM	5 PPM

Alarm light indication is color coded. The alarm light color indication is as follows:

H2S: Blue **CO:** Red **SO2:** Yellow

Each sensor is tied in with its own individual alarm horn. This horn will give off a tone alarm to indicate a sensor has detected a gas level of at least its trip point. The individual horns are connected with a common alarm that will emit an oscillating alarm. The common alarm will sound at the Gasifier island and through the plant's Gaitronics system. The alarm will pause for two (2) minute spans to allow for announcements over the plant Gaitronics system. Sensor alarms are programmed to continue to activate until the sensor detects no gas emissions above the trip level.

C. Scheduled Routine Inspections:

Procedures have been established for routine inspections of the facility each shift. These inspections may detect fires, or safety hazards, and for this reason, immediate implementation of actions is essential for a rapid and effective response.

D. Casual Observer:

Some accidents, incidents and emergency situations can not always be detected by warning/alarm devices and scheduled routine inspections. For this reason, rapid response to these situations must rely on immediate reporting by on-scene witnesses.

5. NOTIFICATION/DUTIES:

A. Person detecting an incident:

Any person detecting an incident is to report the incident/accident immediately to the Control Room. When reporting, as accurately as possible, provide the following:

1. Name of person reporting incident.

2. Location of the incident and equipment involved.

3. Nature of incident (i.e.: injury to personnel, gas or chemical leak, fire, etc.)

4. If injuries, number of personnel injured and type of injury.

5. If possible, remain near the scene to direct any responding personnel. If the incident is suspected to be a hazardous/toxic gas release **do not** remain in the area, but proceed to the evacuation assembly point.

B. Control Room:

1. If notified from the field, take down all emergency information that was called in. Use the "Emergency Response Form" (Appendix A).

2. In the event the incident is indicated by an alarm on the DCS, note the type and location. Use the "Emergency Response Form" (Appendix A).

3. If needed, SOUND THE PLANT ALARM and make a plant wide announcement to provide incident/emergency type, location & immediate instructions.

4. With the information available, determine the response required. Make the necessary calls and notifications.

6. ACTION RESPONSES:

A. Level 1:

1. Sound the plant alarm and make a preliminary announcement to indicate that an incident has occurred, location and immediate actions to be taken. If the incident is a gas release, evacuate the immediate incident area.

2. The Shift Supervisor, Production Manager and Safety Specialist are to report to the Control Room. If a release or chemical spill is involved also notify the Compliance Specialist to report to the Control Room.

3. If an evacuation had been ordered, obtain a "head count" to account for all on site personnel.

4. Manage the incident under the direction of the Shift Supervisor. Use the "Emergency Response Form" as a check off and guide for management of the incident.

5. Secure entrances to the power station as warranted.

B. Level 2:

1. Sound the plant alarm and make a preliminary announcement to indicate that an incident has occurred, location and immediate actions to be taken. If the incident is a gas release, evacuate the immediate incident area.

2. The Shift Supervisor, Production Manager and Safety Specialist are to report to the Control Room. If a release or chemical spill is involved also notify the Compliance Specialist to report to the Control Room.

3. If an evacuation had been ordered, obtain a "head count" to account for all on site personnel.

4. Manage the incident under the direction of the Shift Supervisor. Use the "Emergency Response Form" as a check off and guide for management of the incident.

5. Utilizing the **911 emergency number** call the emergency dispatch to request fire and sheriff department assistance. If personnel injuries have occurred, request medical assistance.
(NOTE: Due to weight restrictions of the access bridge (5 ton), advise the dispatcher entrance of fire fighting equipment, etc. is to be through the west gate accessed from the Patrick/Waltham exit #28. Station an employee at the gate entrance to guide emergency response vehicles.)

6. If there are personnel injuries that warrant, contact Care Flight (856-9111).

7. Secure all power station entrances to restrict unauthorized entry onto the station.

7. SYNGAS AREA EVACUATION:

A. General:

In an emergency situation, or by direction of the Control Room, personnel shall evacuate the Syngas Areas and assemble at the "Primary" assembly site. If the "Primary" assembly site is not deemed safe, personnel will be directed to assemble at the "Secondary" site. The chosen site location will be announced by the Control Room via Gaitronics and radio. Upon arrival, give your name to the most senior Sierra employee present. The most senior Sierra employee will advise the Control Room they are prepared to provide a head count. When needed the Control Room will contact that individual for a head count and to provide further instructions.

PRIMARY ASSEMBLY AREA: **Steam Turbine Building**
SECONDARY ASSEMBLY AREA: **Waste Water Treatment Building**
ADDITIONAL ASSEMBLY AREA: **As announced by Pinon Control Room**

B. Gas Release:

In a gas release situation, personnel safety is the primary concern. Until the size of the release determined, all occupants of the Syngas Areas are to immediately don a five minute escape mask upon the sounding of the alarm and announcement from the Control Room. Proceed out of the Syngas Area to the designated evacuation point. ***(NOTE: The 5 minute escape mask is for escape only. It is not to be used to attempt to perform any work functions. No one may re-enter a Syngas Area during leak/alarm conditions without a SCBA and upon instruction from the Control Room.)***

8. SECURITY ISSUES LEVEL 2:

A. A plant employee is to be dispatched to the plant access gates. No one is allowed to leave the property without providing their name and company affiliation to this employee. This information will be relayed to the Control Room.

B. Do not allow any person on site who does not have a part in managing or controlling the incident, without permission from the Shift Supervisor. This may be media, bystanders, or relatives and non-affected employees. Be courteous and helpful, but do not let them in or volunteer any information.

9. LEAK SOURCE DETERMINATION/CORRECTION:

A. Re-Entry:

No one may re-enter a Syngas Area during a leak/alarm situation until authorized by the Control Room.

B. PPE:

Any directed re-entry to determine a leak source, attempt rescue or to correct an alarm condition will require at the minimum use of a SCBA, five minute escape mask, radio and four gas detection device.

C. Buddy System:

No one may be directed to re-enter a Syngas Area alone during an alarm condition. The Buddy system will be in effect and enforced.

D. Back up:

No entry team may enter without an equally equipped back up team stationed on or near the border of the Syngas Area to be entered. The back up team will equal the entry team in numbers. (i.e., 2 entrants = 2 back up.)

10. NOTIFICATION CANCELLATION:

A Level 1 notification shall be in effect until canceled by the Shift Supervisor.

A Level 2 notification shall be in effect until canceled by the Shift Supervisor.

11. RESTORATION TO NORMAL OPERATIONS:

There will be no restoration activities conducted at the site until:

All damage has been documented by written description, pictures, etc., and

An incident report has been completed, and
The area has been tested free of hazardous and flammable substances, and

The Shift Supervisor has declared the emergency over, and

A meeting held, and documented, to review what happened, probable cause, and steps outlined as to how to safely recover.

(NOTE: Any damaged equipment, instrumentation, piping, etc., should be stored as it is for future review and inspection. Insurance and regulatory personnel may demand to inspect it. Do not discard until instructed to do so.)

12. FOLLOW UP:

As soon as practical, all affected employees and other personnel involved shall hold a meeting to critique the existing plan and the specific response. The meeting shall be documented and focus on how to improve and what changes may need to be made.

EMERGENCY RESPONSE FORM

(Check off and fill in as applies)

1. **Emergency Call/Alarm Received:**

Date: ____/____/____ **Time: _____:_____ (24hr.,start time)**

Caller: ________________________ **Alarm: ____________________ (#, type)**

Caller Location: ____

Alarm Location: ____

2. **Location of Release, Medical Emergency, Fire:**

____

____

3A. **Estimated Number of Injured:** **____**

Injury Type: **____**

3B. **Suspected Gas Released:**

Syngas Carbon Monoxide Hydrogen Sulfide Sulfur Dioxide

Other ____

Gas Concentration, if Known: ____________________________________

Estimated Size of Release: **Small** **Large**

Estimated Wind Direction: **_________________________________**

4. **Additional Emergency Reported:** **____**

____

5. **Response Level Type:** **_____ Level 1** **_____ Level 2**

Level 1: Can be handled by on site personnel.

Level 2: Requires the assistance of additional off site resources.

6. **Immediate Actions:**

Alarm Sounded and Announcement made: **(Emergency type & actions to take) (Announcement to be made on Gaitronics and radio. Make every effort to remain calm when making announcements. Speak clearly and slowly.)**

Instruct all personnel in Syngas Areas to evacuate Syngas Areas and proceed to Assembly area. (Primary: Steam Turbine Building, Secondary: Waste Water Treatment Building) Instruct affected personnel to monitor radio channel 2.

Instruct all personnel in Syngas Areas to put on escape masks and proceed to Assembly area. (Primary: Steam Turbine Building, Secondary: Waste Water Treatment Building) Instruct affected personnel to monitor radio channel 2.

Page Shift Supervisor, Production Manager & Safety Specialist. Ask to report to Control Room. (If gas release or chemical spill, also page Compliance Specialist)

Outside Emergency Service Requested: (Dial 911)

Time: _____:_____ (24 hr. clock)

Medical Fire Sheriff Other _________

Air Ambulance (CARE Flight) 856-9111

All On-Duty Personnel Accounted For: (At Control room, or Radio Check)

Plant Shut Down and Depressurization/Purging Started:

Do not attempt any valve closure operations before donning SCBA.
Minimum of two employees equipped with SCBA, gas detector & radio with minimum of two like equipped employees as back up.

If a flammable gas release is suspected, attempt to shut down all fired and electrical equipment.

Emergency First Aid/Rescue Operations Started:

Re-entry into Syngas Area requires minimum of two employees equipped with SCBA, gas detector & radio for entry, with minimum of two like equipped employees as back up. Re-entry may only be made upon approval or instructions received from the Control Room.

All injured personnel requiring transport are to be evacuated to the Waste Water Treatment Building.

Fire Pump Started and Initial Fire Control Started:

Try to contain **incipient** fire with aiming hoses and monitor as best as possible, then leave area. When professional fire department arrives, supply supporting role as directed by fire department.

If fire threatens any vessel or piping containing hazardous or flammable material, immediately shut down the plant and start purging.

Sierra Employee Dispatched to Gates:

Direct emergency services personnel (fire, ambulance, etc.).

Secure site from entry by Non-essential personnel.

Account for All Other On Site Personnel:

Persons Reported Missing and Last Reported Location:

____

____

____

A roll is to be taken by the most senior SPPCo employee at each assembly site and called into the Control Room.

Employees are to stand by for assignments from the Control Room.

Manage/Investigate Gas Release Situation:

Establish Entry and Back Up Teams To Investigate Leakage.

Until notification has been canceled, entry may only be made by Entry Team equipped with SCBA, gas monitor and radios. An equally equipped Back Up Team must be available at the barrier zone before Entry Team is given instructions to enter the Syngas Area, or other hazardous area.

Entry Team Instructed to Proceed and Investigate.

At no time is the Entry Team to attempt any tasks that have the potential of placing them in danger or adversely affecting their safety. If any doubt exists, the Team will be instructed not to enter. If any adverse situation is noted after entry, the Team is to exit immediately!

7. Emergency Notification:

Shift Supervisor	Time: _____:_____ (24 hr. clock)
Production Manager	Time: _____:_____ (24 hr. clock)
Safety Specialist	Time: _____:_____ (24 hr. clock)
Compliance Specialist	Time: _____:_____ (24 hr. clock)
Rescue Team	Time: _____:_____ (24 hr. clock)
System Control	Time: _____:_____ (24 hr. clock)
VP Electric Production	Time: _____:_____ (24 hr. clock)
____________________	Time: _____:_____ (24 hr. clock)
____________________	Time: _____:_____ (24 hr. clock)

8. Other Outside Agencies/Contractors Contacted:

____________________	Time: _____:_____ (24 hr. clock)
____________________	Time: _____:_____ (24 hr. clock)

9. **Time Notification Canceled, Emergency Ended:** _____:_____ **Date:** ___/___/___

Authorized By(Name/Title): ____

10. **Name and Title of Person(s) Taking & Logging Report:** _______________________

____

____

11. **Log of Actions (Narrative):**

____

____

____

____

____

____

____

____

____

____

____

(USE AS MANY ADDITIONAL SHEETS AS NECESSARY TO DESCRIBE EVENTS.)

Pinon Pine
Coal Gasification/Syngas Safety Procedures

Vendors/Visitors

1. SCOPE:

The following will apply to allow the safe delivery of needed items (chemicals, coke, limestone, etc.) & visits by vendors, off site based Sierra Pacific employees and others near or in the **Process Area**.

2. DEFINITIONS:

A. Vendor:

Any individual(s) whose purpose on site is to conduct business with SPPCo. or to deliver/pick up items per a business agreement with SPPCo..

B. Visitor:

Any individual who is not an employee of the Tracy Power Station. For the purpose of visitation near or in the Process Area, this includes any SPPCo.employee that is not based at the Tracy Power Station and has not received Syngas training.

C. Boundaries, Process Area:

To provide for the safety of Visitors/Vendors, and to minimize unauthorized entry to potentially hazardous areas, the **Process Area** boundaries are larger than those established for the "Syngas Areas". (see "Coal Gasification/Syngas Safety Procedures, Normal Operations")

The **Process Area** Boundary is defined as all items/structures between the roadway on the west side of the silos to the roadway on the east side of the Power Island; between the roadway south of the Gasifier & Power Island to the roadway north of the Power Island. This area includes the east/west pipe rack between the Gasifier and the Steam Turbine building; the north/south pipe rack between the Power Island and the Steam Turbine building & Gasifier; the sulfuric/caustic storage area on the west side of the Steam Turbine Building; and all points within a twenty (20) foot radius of the flare and flare piping. The Steam Turbine building is not included within this boundary area. See attached map.

3. ACCESS:

A. Deliveries/Pick up:

Vendors making a delivery to, or picking up items from/near the Process Area will contact either the Main Office or the Control Room to advise of their presence and purpose. The Main Office or Control Room will notify the responsible contact employee. The responsible employee will either escort the vendor to the delivery/pick up point, or advise of the routing to use and meet the vendor at the delivery/pick up point.

(Note: Dedicated LASH drivers that have received area hazard training may be allowed to pick up LASH without a plant escort. Drivers will be required to advise the Control Room on arrival and departure. LASH drivers will not be allowed in any area other than the immediate vicinity of the silo.)

1. Routing:

Vendors making a delivery/pick up will proceed from the gate to the scale. If the delivery/pick up requires, the driver will stop at the scale for weighing. From the scale, the vendor will proceed west to the north/south roadway running from the Waste Water Treatment building to the silos and proceed north to the delivery/pick up point. Exit will be made by heading south on the roadway running under the Lash silo, and reverse routing from there to the gate.

B. Others:

All other Visitors/Vendors will report to the Main Office. The responsible party will be contacted, meet with the Visitors/Vendors and escort them to the area to be visited.

Non -Tracy Power Station based SPPCo. employees are to contact the Control Room upon their arrival. If their assigned task requires them to be in or near the Process Area, they are to be escorted by a Tracy Power Station employee.

4. RESTRICTIONS:

A. Escorts:

No Visitor/Vendor may enter the Process Area unless escorted by a SPPCo. employee based at the Tracy Power Station.

B. Syngas Areas:

No Visitor/Vendor may enter a Syngas Area (see "Coal Gasification/Syngas Safety Procedures, Normal Operations") without receiving Syngas Area hazard and entry training.

5. COMPLIANCE:

A. Adherence:

Full compliance is required from Visitors/Vendors and any SPPCo. employees.

B. Enforcement:

Any violation of the above will be immediately reported to Management and the Safety Specialist. Failure to comply will result in the following corrective action:

SPPCo. Employees:
Disciplinary action up to, but not excluding termination.

Visitors or Vendors:
Dismissal from the job, or removal from the property.

Date Issued: 04/25/97

PIÑON PINE COMPANY, LLC
MATERIAL SAFETY DATA SHEET

NOTE: Read and understand Material Safety Data Sheet before handling or disposing of product.

1. CHEMICAL PRODUCT AND COMPANY IDENTIFICATION

MATERIAL IDENTITY

Product Code and Name:
SYNGAS, mixture

Chemical Name and/or Family or Description:
Gasification Stream

Manufacturer's Name and Address:
Pinon Pine Company, LLC
191 Wunotoo Road
Sparks, NV 89434-6609

Telephone Numbers:
(702)834-4683

2. COMPOSITION/INFORMATION ON INGREDIENTS

Product and/or Component(s) Carcinogens According to :

OSHA	ISTV	NTP	OTHER	NONE
_	_	_	_	X

Chemical Name	CAS No.	Exposure limit	Range in %
Hydrogen	1333740	No OSHA PEL Asphyxiant ACGIH	5.0-20.0
Carbon Monoxide	630080	35 ppm TWA 200 ppm Ceiling	15.0-30.0
Carbon dioxide	124389	10,000 ppm TWA 30,000 STEL	4.-10.0
Hydrogen sulfide	7783064	10 ppm TWA 20 ppm Ceiling	0.01-1.0
Ammonia	7664417	50 ppm TWA	0.0-1.0
Methane	74828	not established Asphyxiant ACGIH	1.0-3.0
Carbonyl Sulfide	463581	not established	1.0-3.0

3. HAZARD IDENTIFICATION

EMERGENCY OVERVIEW

Appearance and Odor: Colorless gas

WARNING STATEMENT

DANGER: EXTREMELY FLAMMABLE
MAY BE FATAL IF INHALED
MAY RELEASE HYDROGEN SULFIDE (H2S) GAS
MAY CAUSE EYE IRRITATION

NFPA

Health:	3	Reactivity:	0
Flammability:	4	Special:	-

POTENTIAL HEALTH EFFECTS

	EYE	SKIN	INHALATION	INGESTION
Primary Route of Exposure :	X	X	X	_

Effects of Overexposure

Acute

Eyes:

May cause irritation, experienced as discomfort, and seen as excess redness and swelling of the eye.

Skin:

May cause skin irritation.

Brief contact may cause skin irritation. Prolonged contact, may cause defatting of skin, or irritation, seen as local redness with possible discomfort.

Inhalation:

Prolonged overexposure may cause headache, nausea, vomiting, fatigue, weakness, drowsiness, and collapse. Severe overexposure may result in unconsciousness and coma. Extreme overexposure may result in death.

Contains or may release hydrogen sulfide (H2S) gas. H2S mouthfuls are swallowed, abdominal discomfort, nausea, and diarrhea may occur. H2S concentrations above permissible concentrations can cause headache, dizziness, nausea, vomiting, and diarrhea. At concentrations above 300 ppm, respiratory paralysis, causing unconsciousness and death, can occur.

Ingestion:

No adverse effects expected. If more than several mouthfuls are swallowed, abdominal discomfort, nausea, and diarrhea may occur.

Sensitization Properties:

Unknown.

Chronic:

Repeated over exposure to carbon monoxide may cause nervous system damage experienced as poor memory, numbness of the hands and feet and personality changes.

Repeated inhalation may cause lung damage.

Medical Conditions Aggravated by Exposure:

Repeated over exposure may aggravate or enhance existing nervous system dysfunction produced by disorders known to cause nervous system effects or damage such as diabetes, alcohol or drug abuse, and Parkinson's disease.

Skin contact may aggravate an existing dermatitis (skin condition).

Other Remarks:

Carbon monoxide decreases the ability of blood to carry oxygen. Symptoms of overexposure include headache, shortness of breath, nausea, vomiting, confusion, irritability, and weakness. Severe overexposure may cause increased breathing rate, increased heart rate, chest pain, hallucinations, staggering, convulsions, and collapse. Cherry-red color of lips and nail beds is seen only as a late sign of carbon monoxide poisoning.

Hydrogen sulfide (H2S) causes irritation of the eyes and respiratory tract. Repeated overexposure to H2S may cause bronchitis, persistent eye irritation of the eyes and respiratory tract. Repeated overexposure to H2S may cause bronchitis, persistent eye irritation and chest congestion. Prolonged exposure to high concentrations can produce pulmonary edema.

4. FIRST AID MEASURES

Eyes:

Immediately flush eyes with plenty of water for at least 15 minutes. Hold eyelids apart while flushing to rinse entire surface of eye and lids with water. Get medical attention.

Skin:

Wash skin with plenty of soap and water for several minutes. Get medical attention of skin irritation develops or persists.

Ingestion;

No emergency care anticipated. this material is a gas at standard temperature and pressure.

Inhalation:

Remove to fresh air, if not breathing, give artificial respiration. If breathing is difficult, or cyanosis (blue discoloration of skin or lips) is noted, qualified personnel may administer oxygen. Get immediate medical attention.

Other Instructions:

Warning: Rescue of overexposed persons should be attempted only after notifying others of the emergency and only if appropriate personal protective equipment and pressure self-contained breathing apparatus (SCSA) is available.

The odor of hydrogen sulfide (H2S) gas is offensive and similar to rotten eggs, H2S gas deadens the sense of smell, even at low concentrations. DO NOT depend on odor to detect presence of gas.

NOTE TO PHYSICIAN: Administer 100% oxygen until carboxyhemoglobin levels are measured. If blood COHb levels exceed 20%, consider hyperbaric C2. Cerebral edema and convulsions must be controlled. Myocardial damage and pulmonary edema may occur. Late, fatal demyelination is a rare complication which occurs after apparent recovery. Contact a Poison Control Center for additional treatment information.

NOTE TO PHYSICIAN: Inhalation exposure to high concentrations may result in the development of pulmonary edema after a latent interval of several hours. Respiratory tract injury caused by pulmonary irritants may predispose patient to secondary respiratory infection. Persons exposed to high concentrations should be retained for observation. Contact a Poison Control Center for additional treatment information.

5. FIRE-FIGHTING MEASURES

Ignition Temp. Degrees F.: 1060 Flash Point Degrees F. (Method): N.D.
Flammable Limits (%) Lower: 4.0 Upper: 75.0

Recommended Fire Extinguishing Agents and Special Procedures:

Do not extinguish flame because of possibility of explosive re-ignition. Shut off source of fuel if possible, and allow fire to burn out. Use water fog to cool fire-exposed surfaces. Extinguish small residual fires with dry chemical or carbon dioxide.

When handling, use non-sparking tools, ground and bond all containers.

Unusual or Explosive Hazards:

Extremely flammable and hazardous. Material may generate heat and/or ignite when exposed to air.

Danger! Extremely flammable materials may release vapors that travel a considerable distance to a source ignition and flash back. Containers may explode in a fire. Do not expose to heat, sparks, flame, static, or other sources of ignition. When handling, use non-sparking tool, ground and bond all containers.

6. ACCIDENTAL RELEASE MEASURES

Procedures in Case of Accidental Release, Breakage or Leakage:

Shut of flow of gas if possible. Isolate area. Keep upwind of leak. Water spray may be effective in dispersing vapors. Eliminate all sources of ignition. Keep people away. Stay upwind and warn of possible downwind explosion hazard. Do not enter area without proper PPE, (self contained breathing apparatus, detection device, skin protection).

7. HANDLING AND STORAGE

Precautions to be Taken in Handling and Storage:

Handle, store and transport according to applicable OSHA and DOT regulations. Ground and bond shipping/sampling container, transfer line, and receiving container. Use spark proof tools. Keep away from heat, sparks, flame or any other source of ignition. Material may be at elevated temperature and/or pressure. Use due care when opening any bleeders or sample ports.

Eye wash and safety shower should be available nearby when this product is handled or used.

8. EXPOSURE CONTROLS/PERSONAL PROTECTION

Protective Equipment (Type)

Eye/Face Protection

Avoid eye contact. Chemical type goggles should be worn. Do not wear contact lenses.

Skin Protection:

Workers should wash exposed skin several times daily with soda and water. Soiled work clothing should be laundered or dry-cleaned at lease once a week. Long sleeve clothing should be worn where exposure is possible.

Respiratory protection:

When Hydrogen Sulfide (H2S) concentrations are unknown or are equal to or greater than 10 ppm. (as in such activities as: loading; unloading; gauging ; cleaning large spills or upon entry into tanks, vessels, or other confined spaces; and during rescue of individuals suspected to be overexposed to H2S), use supplied-air (airline or self-contained breathing apparatus) respiratory protection (NIOSH/MSHA Approved). The respirators must be equipped with pressure-demand regulators and operated in the pressure demand mode ONLY. If airline units are used, a 5-minute escape bottle MUST also be carried. AIR-PURIFYING RESPIRATORS MUST NEVER BE USED FOR H2S DUE TO POOR WARNING PROPERTIES OF THE GAS. When concentrations are unknown of any component, do not use air purifying respirators. Use only supplied air respirators operated in the positive pressure mode.

Air-purifying respirators may not be used in any IDLH atmosphere.

Ventilation:

Adequate to meet component occupational exposure limits (see Section 2).

Exposure limit for total product:

None established for this product mixture; Refer to Section #2 for individual component permissible concentration.

9. PHYSICAL AND CHEMICAL PROPERTIES

Appearance and Odor: Colorless gas, may have slight/mild rotten egg odor.		
Boiling Point (degrees F.): GAS	Percent VOC: 100	
Specific Gravity: N.A. (H2O=1)	Vapor Density: 0.85	Air=1
pK of undiluted product: N.A.	Solubility in Water: N.D.	
Vapor Pressure: N.D. mmng		
Viscosity: N.A.	Other: N.D.	

10. STABILITY AND REACTIVITY

This Material Reacts Violently With: (if others is checked below, see comments for details)

Air	Water	Heat	Strong Oxidizers	Others	None of These
_	_	Y	Y	_	_

Comments:
None

Product Evolved When Subject to Heat or Combustion:

Toxic levels of carbon monoxide, carbon dioxide, irritating aldehydes and ketones, and combustion products or compounds of sulfur., including hydrogen sulfide

		OCCUR	DO NOT OCCUR
Hazardous Polymerizations:	_	X	

11. TOXICOLOGICAL INFORMATION

TOXICOLOGICAL INFORMATION (ANIMAL TOXICITY DATA)

Median Lethal Dose (LD50) (Species)

Oral: Not applicable, material is a gas

Inhalation: 600 ppm H2S/30 minutes (rat)

Dermal: Not applicable
Irritation Index, Estimation of Irritation (Species)
Skin: believed to be < 0.5/8.0 (rabbit): no appreciable effect
Eyes: H_2S - slight-severely irritating
Sensitization: N.D.
Other:
None

12. DISPOSAL CONSIDERATIONS

WASTE DISPOSAL METHODS

This product has the RCRA characteristics of ignitability, and if discarded in its present form, would require a hazardous waste number. Under RCRA, it is the responsibility of the user to determine, at the time of disposal, whether the product meets RCRA criteria for a hazardous waste. Product uses, mixtures, processes, etc., may change the classification to non-hazardous, or hazardous for reasons other than, or in addition to ignitability.

REMARKS

Do not allow to enter drains or sewers. Can cause explosion.

13. TRANSPORT INFORMATION

TRANSPORTATION

DOT: Proper shipping name: Compressed gas, flammable, N.O.S.

HAZARD CLASS: 2.1, PG-none assigned
IDENTIFICATION NUMBER: UN1954
LABEL REQUIRED: Flammable gas

IMDG: PROPER SHIPPING NAME: N.D.

IATA: PROPER SHIPPING NAME: N.D.

TDG: PROPER SHIPPING NAME: N.D.

14. REGULATORY INFORMATION

A. SARA TITLE

Title III Section 302/304 Extremely Hazardous Substance:

Component	CAS NO.	Percent	RO (1 lbs.)	TPO (lbs.)
Hydrogen sulfide	7783064	0.01 - 1.0	100	500

CERCLA Section 102 (a) HAZARDOUS SUBSTANCE

Component	CAS NO.	Percent	RO (1 lbs.)
Hydrogen sulfide	7783064	0.01 - 1.0	100

Title III Section 311 Hazard Categorization

Acute	Chronic	Fire	Pressure	Reactive	Not Applicable
X	_	X	_	_	_

Title III Section 313 Toxic Chemicals:

Component	CAS NO.	Percent
None		

15. OTHER INFORMATION

Hazardous concentrations of hydrogen sulfide (H2S) gas can accumulate in storage and rundown tanks, marine vessel compartments, sump pits or other confined spaces,. When opening valves, hatches and dome covers, stand upwind, keep face as far from the opening as possible and avoid breathing any gases or vapors. When exposure concentrations are unknown and respiratory protection is not used, personal H2S warning devices should be worn. These devices should not be relied on to warn of life threatening concentrations. H2S fatigues the sense of smell rapidly. The rotten egg odor of H2S disappears quickly, even though high concentrations are still present. The ACGIH TLV/TWA for H2S is 10 ppm; the ACGIH STEL is 15 ppm.

Dispose of as a vapor, venting to suitable combustion chamber.

All exposures to this product should be minimized by strictly adhering to recommended occupational control to avoid any potential adverse health effects.

The information contained herein is believed to be accurate. It is provided for the intent of Hazard Communication. It is not intended to constitute performance information. Although reasonable care has been taken in the preparation of the contained information, Pinon Pine Company, LLC extends no warranties, makes not representations and assumes no responsibility as to the accuracy or suitability of such information for application to users intended usage, purposes or consequences of its use.

Inquiries regarding MSDS should be directed to:
Pinon Pine Company, LLC
191 Wunotoo Road
Sparks, NV 89434

PLANT MANAGEMENT OF CHANGE

PROCEDURE

PURPOSE
This procedure is intended to increase the awareness of plant staff concerning their responsibilities to ensure that "management of changes" are in compliance with best engineering, safety, and environmental practices and current OSHA regulations.

REQUIREMENT
All plant operations, maintenance, planning, and engineering staff are to be instructed as to the purpose and scope of this procedure as a component of their job description.

INTENT
Plant management does not want changes to be made in the field by any of it's employees without first following a rigid discipline of review and assessment of proposed design or process modifications to plant facilities or operating practices. We must ensure that the proposed change will not compromise any aspect of personal safety or facility integrity. To this end a written "management of change" procedure will be required on all jobs.

SCOPE
This procedure applies to any change in process, technology, equipment and facilities. It does not apply to "replacement in kind" which is taken to mean a replacement which satisfies the original design specification. Change includes all modifications to equipment, procedures, raw materials and process conditions other than "replacement in kind". These changes need to be properly managed by identifying and reviewing them prior to implementation of the change. For example, the operating procedures contain the operating parameters (pressure limits, temperature ranges, flow rates, etc.) and the importance of operating within these limits. While operations must have the flexibility to maintain safe operation within the established parameters, any operation outside these parameters requires review and approval by a written management of change procedure.

Management of change covers all changes in the process technology and changes to equipment and instrumentation.

Changes in process technology can result from any of the following: production rates, catalysts (i.e. sorbent, LOA, etc.), or raw materials: experimentation, equipment unavailability; new equipment; new product development; and changes in operating conditions to improve performance.

Equipment changes include, among other things, the following: changes in materials of construction or equipment specifications; piping re-arrangement; experimental equipment; computer program revisions (including PLCs); and changes in alarms and shutdown interlocks. Plant Services staff need to establish means and methods to detect both technical and mechanical changes.

Temporary changes have caused a number of catastrophes over the years in many different types of plant environments, and plant services need to establish ways to detect temporary changes as well as those that are more permanent. It is important that a time limit for temporary changes be established and monitored since, without control, these changes tend to become permanent. Temporary changes are also subject to management of change provisions.

In addition, the management of change procedures are used to ensure that the equipment and operating procedures are returned to their original or designated conditions at the end of the temporary change.

Proper documentation and review of these changes is necessary to ensure that safety and health considerations are being incorporated into the operating procedures and the process.

A form to facilitate the process of changes through the “management of change” procedure is shown in **Attachment 1**. The change form includes the following:

- A description and the purpose of the change.
- The technical basis for the change including safety, environmental, and health considerations if applicable.
- Documentation of changes for the operating procedures.
- Maintenance procedures.
- Inspection and testing.
- P&Ids.
- Electrical classification.
- Training and communications.
- Prestart-up inspection.
- Duration (if a temporary change).
- Approvals and authorization.

Where the impact of the change is minor and well understood, a checklist reviewed by an authorized person with proper communication to others who are affected may be sufficient. However, for a more complex or significant change, a hazard evaluation procedure with approvals by operations, maintenance, safety, and environmental departments may be appropriate.

Changes in P&Ids, raw materials, operating procedure, mechanical integrity, programs and software, electrical classifications, etc. need to be noted so that these revisions can be made permanent when the drawings and procedures manual are updated.

Copies of process changes need to be kept in an accessible location to ensure that design changes are available to operating personnel as well as to **PROCESS HAZARDS ANALYSIS (PHA)** team members when a PHA is being done or when one is being updated.

GENERAL GUIDELINES

ORIGIN OF CHANGE OR PROBLEM DRIVING CHANGE:

- Operation or maintenance identification of plant problem or concern.
- Engineering (Process or Performance), safety, or environmental specialist identification of concern or need for design modification.

NOTE: Concern or problem should be fully explained or identified by originator. Concern or problem should be further identified as a (1) safety issue, (2) environmental issue, (3) necessary to maintain operation, (4) necessary to improve operation, or (5) highly desirable. Normal or routine operations and maintenance issues are not subject to the Management of Chance Process.

PROBLEM OR CONCERN ASSIGNED TO RESPONSIBLE PLANT ENGINEER FOR FURTHER INVESTIGATION:

- Responsible engineer meets with originator for additional information as necessary to identify the "who, what, when, where, and why" of the issue.
- **"Basis of design"** for change drafted.
- Responsible engineer assembles all existing drawings/specifications affected by the issue and the possible resolution of the issue.
- Responsible engineer identifies design alternatives and associated costs. (May be provided by others).
- **Responsible engineer identifies groups or individual(s) needed to support design and/or implementation of change. This may also be the PHA team and may include "in house" or "contract" engineering and construction personnel.**

MANAGEMENT OF CHANGE STUDY CONDUCTED

- Team members meet to discuss issue and proposed design changes.
- Team reviews each aspect of change and attaches significance, consequences, safeguards and required actions to each.

RESPONSIBLE ENGINEER AND "SUPPORT TEAM" MEET TO DISCUSS ALTERNATIVES AND FINALIZE SOLUTION

- **"Basis of design"** for change finalized based on results of "Management of Change Study".
- Team reviews alternatives for compliance with all user, code, and regulatory requirements and modifies alternatives and associated costs as necessary.
- Responsible engineer provides station manager with document identifying alternatives with cost and **"recommendation alternative"** for approval.

SPECIFICATIONS AND DRAWINGS ARE DEVELOPED TO IMPLEMENT CHANGE

- Engineer modifies plant drawings/specifications or develops new drawings/specifications to detail work.

WORK ISSUED TO IMPLEMENT CHANGES

- Material procured based on modification requirements.
- Contracts or work orders issued to modify plant system(s).
- Responsible engineer or designee monitors/inspects work in progress for compliance to specifications and design drawings (including witnessing tests and coordinating outside code activities if required).
- "Post Mortem" review of work to confirm work installed per "design basis", specifications and drawings.
- Responsible engineer or designee "signs off" on completed work.

WORK DOCUMENTS COMITTED TO FILE

- **"Red line"** drawings prepared and sent to plant document control for processing **"as built"** and filed.
- Inspection sheets, "sign off" documents finalized and sent to plant document control center for filing.

AFFECTED USER(S) STATUSED ON REVISED OPERATIONS/MAINTENANCE PERAMETERS

- Revised drawings issued to user groups.
- Training arranged to update user groups on (1) basis of change, (2) revised operating requirements (if applicable), (3) special conditions, etc. as required.

ATTACHMENT 1

MOC #____________

Clearance Form for Changes to Processes or Plant Facilities covered by Management of Change

Description and Purpose of Change (include process, P&ID number(s), or other relevant documentation)

Duration of Change	Type of Change	Documentation Impact
☐ Permanent	☐ Process	☐ Procedures
From___________	☐ Equipment	☐ Process Hazards Analysis
	☐ Technology	☐ Inspection and Testing
☐ Temporary	☐ Procedures	☐ P&Ids
From_____To______	☐ Facilities (affecting process)	☐ Electrical Classification
	☐ Test or Experiment	☐ Training and Communication
	☐ Operating Parameters	☐ Pre-startup Inspection
	☐ Other_______________	☐ Other_____________

Technical Basis for the change.

Considerations for review of impact to safety, health, and environment (a "yes" answer to any of the questions requires follow up review and evaluation).

Does this change increase the consequences or a previously analyzed safety or hazard concern?
YES NO

Does this change create a possibility of a previously analyzed safety or hazard concern?
YES NO

Does this change create a possibility of a new safety or hazard concern?
YES NO

Does this change reduce the margin of safety for the process or facility?
YES NO

List additional safety, environmental, or health considerations that require follow up review and/or evaluation.

List and attach documents to be modified: Operations Maintenance Department Engineering Safety Environmental Other_____________	Follow up prior to approval required by:

Originator:	Date:
Reviewed by:	Date:
Authorized by:	Date:

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