Topics:
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EPRI AP-5276
Project 1461-1
Final Report
June 1987

Availability Analysis of an Integrated Gasification–Combined Cycle

Prepared by
ARINC Research Corporation
Annapolis, Maryland

REPORT SUMMARY

SUBJECTS	Reliability, operations, maintenance, and human factors / Gasification power plants	
TOPICS	Availability Reliability	Maintenance GCC power plants
AUDIENCE	R&D engineers / Generation planners	

Availability Analysis of an Integrated Gasification–Combined Cycle

Employing the latest component reliability and performance data, investigators analyzed the availability implications of various IGCC design alternatives. The work, representing the most in-depth analysis of IGCC availability performed to date, can aid designers in meeting plant availability targets.

BACKGROUND Integrated gasification–combined cycles (IGCCs) constitute a promising new technology for electric power generation. IGCC technology is economically competitive and offers a superior method of removing sulfur from coal. Because of these benefits, many utilities have initiated generation planning studies that incorporate IGCC plants or phased construction of IGCCs into their future resource plants. Availability estimates are an important requirement for these studies. Because equipment availability and off-design performance estimates are more refined than in the past, IGCC availability estimates can now be performed with greater confidence.

OBJECTIVES To develop availability estimates of various operational and design alternatives for mature commercial IGCCs; to develop alternative scheduled maintenance plans for a commercial, multitrain IGCC.

APPROACH As a basis for their availability analysis, the investigators used the design for the commercial, multitrain Texaco-based IGCC described in EPRI report AP-3486. They performed analyses of each section of this plant and created fault trees to represent the failure modes. After developing estimates of plant output for each failure mode, the researchers employed EPRI's UNIRAM computer model to represent the interrelationships between the plant sections and to yield overall estimates of plant availability. In a separate effort, the project team developed several 10-year scheduled maintenance plans for the same multitrain IGCC plant.

RESULTS This report contains component reliability estimates, a methodology for analyzing IGCC availability, and plant design guidelines. It can be used as a manual for facilitating the design of IGCCs to meet plant availability targets.

• The equivalent availability estimate for the IGCC plant studied in this project was 86.2%. This value represents the coal-based power production capability of the plant after allowing for scheduled maintenance and forced outages. Allowing for the capability of an IGCC plant to employ a backup fuel increases overall equivalent availability to 91.5%.

• The study rigorously evaluated the effects of incorporating in-system storage points in an IGCC plant. One finding was that storing liquid oxygen improved plant equivalent availability by 0.6 percentage points.

• The various maintenance plans developed in the project reflected different maintenance philosophies. For example, some plans allowed for shift maintenance and others did not. Some plans imposed spare parts limitations and others did not. Scheduled outage estimates for the range of investigated approaches to maintenance planning varied from 4.7 to 8.8%.

EPRI PERSPECTIVE This availability analysis was performed for one type of IGCC plant and one particular design. However, the methodology—including some of the fault trees—will be useful for performing analyses of alternative IGCC configurations and other types of plants. Furthermore, as improved component availability estimates are attained—particularly from the Cool Water IGCC plant—EPRI will update the results in this report.

PROJECT RP1461-1
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Availability Analysis of an Integrated Gasification–Combined Cycle

AP-5276
Research Project 1461-1

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NOTICE

Prepared by
ARINC Research Corporation
Annapolis, Maryland

ABSTRACT

The Electric Power Research Institute (EPRI) contracted with ARINC Research Corporation to perform availability assessments of an integrated coal gasification-combined-cycle (IGCC) design. The objective of the study was to quantify the availability impact associated with several design and operating options specified by EPRI. In addition, several scheduled maintenance options for the IGCC plant were evaluated.

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SUMMARY

BACKGROUND

In recent years the electric utility industry has expressed increasing interest in the subject of integrated-gasification-combined-cycle (IGCC) plants. As a consequence of the mid-1984 successful startup and operation of the first commercial-scale IGCC at the Southern California Edison Cool Water generating station, coal gasification has become a near-term option for utility power generation.

EPRI has sponsored a number of gasification-related projects ranging from the construction of the Cool Water plant, to pilot plant coal-burn runs, to engineering and economic evaluations of IGCC plants. The most recent EPRI-sponsored detailed availability analysis of a mature commercial IGCC design was completed by ARINC Research Corporation in early 1982. Since that time, better estimates of availability for some of the components within the IGCC have become available. Furthermore, greater definition has been achieved in the off-design performance of all of the components within the IGCC and of the interactions between these components in their off-design condition.

Also during this time, many electric utility planners have initiated generation planning studies that incorporate IGCCs or the phased construction of IGCCs into their future resource plans. In order to evaluate a new generating technology such as gasification, the planner must have estimates not only for the plant performance and cost but also for the expected plant availability. Because the planner may be evaluating a number of design and operational alternatives in the IGCC plant, availability measures for each alternative would be required in order to properly assess the options.

OBJECTIVES

The objectives of the study reported here are fourfold.

- To develop availability estimates for mature commercial IGCCs employing the most current component reliability data and performance data.
- To evaluate the availability implications of various operational and design alternatives.
- To develop scheduled maintenance plans for a commercial, multi-train IGCC.
- To provide a basis for future work in the area of IGCC availability as improved estimates become available, particularly from the Cool Water plant.

APPROACH

The IGCC design, which served as a basis for the availability analyses described herein, was originally reported in EPRI report AP-3486. This design was developed by Fluor Engineers, Inc. and consisted of an IGCC plant with four gasification trains, which incorporated the Texaco, Inc. coal gasification technology and three combustion turbine trains.

From this reference design a number of other baseline and sensitivity cases were developed with the objective of assessing the impact of various design and operational alternatives on the overall plant availability.

A component reliability data base in the form of estimates of mean downtime and mean time between failures was assembled from a number of sources. Texaco, Inc. supplied reliability estimates for the gasification components. Published data from Air Products and Chemicals, Inc. was used for the oxygen plant reliability. Fluor Engineers, Inc. and EPRI provided input for a number of other components throughout the plant, and where no updated estimates were required, ARINC Research employed the component data from the earlier (January 1982) study of IGCC availability reported in EPRI reports AP-2202 and AP-2205.

Once this component data was assembled, fault trees were prepared to depict the relationship between component failures and subsystem failures. System storage points and subsystems were, in turn, logically connected through an availability block diagram to depict (or "model") the relationship between their individual failures and the overall plant output.

In order to develop more realistic estimates of plant availability, EPRI enlisted the services of Fluor Engineers, Inc. for the specific purpose of evaluating the off-design performance of the plant under various conditions (or "states") of failure. Fluor developed estimates of net plant output and heat rate for those states with relatively high probabilities of occurrence (i.e., >1% probability). These Fluor estimates incorporated the effects of nonlinearities in equipment part-load performance. Through having accounted for these nonlinearities, the final estimates of plant equivalent availability and equivalent forced outage rate are more realistic.

ARINC Research then developed a number of plant performance measures, including availability, equivalent availability, and average heat rate. These estimates were developed using an EPRI computer program called "UNIRAM," which is a tool that assists in the analysis of plant availability.

BASELINE CASES

The Design

Three baseline cases were examined as a part of the scope reported here. Each of these cases reflect different operating modes for the same IGCC plant design. The design is based on the Texaco, Inc. coal gasification process and incorporates both radiant and convective coolers immediately downstream of the gasifier. The plant contains four gasification trains and three combustion turbines. The gasification section of the plant was sized to supply the combustion turbines with sufficient fuel to achieve their full output potential at the low ambient temperature condition of 20°F. However, 59°F was the operating condition at which all three baseline cases were examined. Because the capacity of combustion turbines is ambient-temperature-dependent, the 59°F operating condition results in spare capacity in the gasification section of the plant, amounting to 11.2 percent.

This spare gasification capacity can be used, when economic dispatch dictates, to produce coal gas for supplemental firing directly in the heat recovery steam generator (HRSG) duct. This supplemental firing yields more power from the IGCC plant; however, this additional power is obtained at a lower fuel efficiency relative to the base mode of plant operation.

The IGCC design has backup fuel-firing capability in that a natural gas pipeline of sufficient size exists that can fuel the combustion turbines in the event of a disruption in the coal gas supply resulting from some gas plant failure. This backup fuel could just as well have been distillate oil. (The plant performance would have changed only minimally in response to such a change in the backup fuel.)

This IGCC design thus incorporates both supplemental firing capability and backup natural gas capability; however, utility operators would not elect to use these capabilities at all times. Utility system dispatch would determine which operating modes would be employed given both the availability of each mode and the status of the remainder of the plants on the system. Because these different operating modes would likely be dispatched separately, the utility planner must have separate estimates for the performance and availability of each mode. The three baseline cases in this study were designed to accomplish the objective of developing the estimates required.

If the IGCC design being evaluated by a given utility does not have some of the operating flexibility of the above-described baseline IGCC, then the results of the three baseline cases described herein can be used individually or in pairs to generate the data set required. For example, if the utility's plant design has neither supplemental firing nor backup fuel capability, then the results for the case of the base operating mode will provide the utility planner with all of the input needed. Results for the other operating modes, which incorporate supplemental firing and backup fuel, can then be examined from the perspective of the incentives for incorporating greater flexibility into the plant design.

The Results

The "Baseline IGCC" case captures the operating mode of the plant in the absence of both supplemental firing and backup fuel firing. In this case, the 11.2-percent spare gasification capacity operates only when a failure occurs in the gasification plant. The plant full-load capacity was 598 MW.

Results from an analysis of the Baseline IGCC operation reveal an expected plant equivalent forced outage rate of 9.6 percent. When a relatively optimistic scheduled outage rate of 4.7 percent is employed, the resulting plant equivalent availability is shown to be 86.2 (86.18) percent. A pessimistic scheduled outage rate of 9.0 percent would change the equivalent availability estimate to 82.3 percent. The "expected" estimate lies somewhere between these two values.

This high equivalent availability result may appear surprising at first glance since IGCC plants seem complicated, and they contain a large number of components. However, once the spare capacity, the storage capacities, and the effect of a multiplicity of equipment trains is taken into consideration, the result is more understandable. By way of illustration, the above-quoted results for the Baseline IGCC are consistent with a simultaneous probability of only 72 percent that the plant will be in the operating state in which there are no plant failures. (In other words, there is a 72-percent likelihood that the plant can produce its full "nameplate" output.) Furthermore, there is about an additional 25-percent probability that the plant will be in some failure mode (or state) that can yield more than zero output, and only a 3-percent chance that the plant will suffer a failure that will render it unable to produce any output. In summary, because there exists a multiplicity of equipment trains with some spare capacity, there is a substantial probability that the plant can produce power even while experiencing a failure. This factor contributes to the relatively high equivalent availability estimates developed as a part of this study scope.

A second case called the "Baseline with Supplemental Firing" represents the IGCC operating mode in which supplemental (or duct) firing of coal gas occurs whenever there is excess gasification capacity over and above that required to fully load the combustion turbines. This supplemental firing process step has the net effect of increasing the overall plant capacity by 54 MW at the 59°F ambient operating condition. These additional 54 megawatts are available somewhat less frequently than is the Baseline IGCC mode because more equipment is required for the operation of supplemental firing: The duct burner, the associated piping, and the fuel flow control equipment must all be available in order to operate in the supplemental firing mode. This equipment has a 99.89-percent probability (per HRSG) of being available. Therefore, the supplemental firing mode would be available as long as the baseline IGCC mode is available (86.2 percent of the time) and the special equipment for supplemental firing is available (99.89 percent of the time).

Another way of looking at the availability of the Baseline with Supplemental Firing would be to represent the baseline operating mode and the supplemental firing mode all as a single operational alternative. If the plant were considered a single 652 MW plant (instead of a plant with 598 MW plus 54 MW), then the plant equivalent availability could be determined by evaluating the probability of achieving all or a part of the 652 megawatts. When considered in this fashion, the plant equivalent availability is 85.6 percent as compared with 86.2 percent for the Baseline IGCC mode of operation. An important factor to keep in mind when comparing these two equivalent availability estimates is that one represents the availability of 652 MW of capacity whereas the other reflects the availability of only 598 MW. This capacity difference will be very significant when considering the utility system reliability.

As indicated by the foregoing discussion, the effect of this 54 megawatts of supplemental firing capability on both the plant and utility system availability is difficult to measure. From one perspective this capacity can be considered as spare plant capacity, which can be used in the event of an IGCC partial outage for the purpose of enhancing the plant output and thus improving the plant equivalent availability. From another perspective this capacity can be considered as somewhat separate from the IGCC. It then represents additional system capacity with its own availability characteristics, the presence of which can reduce the utility system loss-of-load probability.

Another factor that compounds the difficulty of measuring the availability implications of supplemental firing capability lies in the ambient temperature sensitivity of this capacity. In the Baseline IGCC, the supplemental firing capacity varies all the way from zero megawatts at 20°F ambient to 74 megawatts at 88°F ambient. The value of this capacity to a utility will depend on the relationship between the ambient temperature at the plant site and the concurrent utility system load.

The third and final baseline case was called the "Baseline with Natural Gas Backup." In this case, the backup fuel was available to make up for any loss of coal gas availability due to a failure in the plant. No supplemental firing operation was assumed for this case. Through the use of backup fuel, simple-cycle (i.e., combustion turbine but not steam turbine) operation was assumed feasible. Together these additional operating flexibilities led to an equivalent availability estimate of 91.5 percent, as compared with 86.2 percent for the Baseline IGCC. From these results it becomes apparent that backup fuel firing capability is valuable in terms of plant availability. This conclusion is valid even if this backup mode is not dispatched frequently.

Criticality Rankings

In order to ascertain which sections of the IGCC plant contribute most to the plant unavailability, the sections (or subsystems) were ranked according to their criticality. Table S-1 shows a listing of subsystem criticality. This list is based on the impact that each subsystem would have on the plant equivalent forced outage rate if the subsystem were to be made perfectly available. Notice that the

Table S-1

CRITICALITY RANKING

Subsystem	Expected EFOR Decrease if Subsystem Were Perfectly Available	
	Baseline IGCC (Percent)	Baseline With Natural Gas Backup (Percent)
Gasification High-Temperature Gas Cooling, Scrubbing	2.79	N/A
Combustion Turbine, Generator	2.19	2.22
Steam Turbine, Generator	1.49	.68
Ash Dewatering	.69	N/A
HRSG	.66	.60
Acid Gas Removal	.65	N/A
All Others	<.65	<.57

gasification section is the most critical component for the Baseline IGCC case, but that for the Baseline with Natural Gas Backup case, the most critical component is the combustion turbine.

At times, a design engineer is faced with the need to redesign a plant in order to increase or decrease plant reliability in the best fashion possible. Alternatives at the engineer's disposal include: 1) modifying the subsystem or component spare capacity in the plant, 2) specifying components with different reliability characteristics, and 3) modifying the capacity of the intermediate storage points. In order to accomplish this redesign the engineer needs to know the subsystem criticality rankings as well as the economics of any design change. Table S-1 provides the first of these two input requirements. However, the second element, the cost estimates, is beyond the scope of this study.

SENSITIVITY CASES

Additional Spare Gasification Capacity

Commercial experience with the Texaco coal gasification process has not yet yielded a definitive throughput capacity of a commercial-scale gasifier. As a case in point, the primary gasifier at the Cool Water plant has already operated in excess of its nameplate rating, but because of oxygen plant capacity limitations and regulatory restrictions, this gasifier capacity has never been extended to its physical limits.

Because there is a certain undefined amount of conservatism in the rating capacity of gasification trains, a sensitivity study was conducted to investigate the significance, in terms of plant availability, of the amount of spare gasification capacity. This sensitivity study will also prove to be a useful guide in determining the required number of gasification trains when designing IGCC plants to achieve certain availability targets.

Figure S-1 depicts the response of the Baseline IGCC equivalent availability to changes in spare gasification capacity. As the spare capacity increases, the equivalent forced outage rate decreases and the equivalent availability increases. It should be noted that as spare gasification capacity increases, the plant equivalent availability asymptotically approaches 90.2%. This trend indicates that even if the gasification section were perfectly available, the scheduled maintenance requirements and the unavailability of the balance-of-plant would limit the overall plant equivalent availability to 90.2%.

Once 33.3-percent spare gasification capacity exists in the plant, a full spare gasification train is available for use in facilitating the scheduled rebricking of gasifiers. If one gasifier at a given time is on scheduled maintenance for rebricking, the entire plant unavailability due to <u>scheduled</u> outages of the gasifiers can be eliminated. Thus, the discontinuity in the curve of Figure S-1 reflects the change in the plant scheduled outage rate from 4.7 percent to 3.2 percent, which is attributable to the full spare gasifier.

The results of Figure S-1 are based on the assumption that all gasifier maintenance is performed simultaneously until the point that one full gasifier is unavailable. At this point, the gasifier rebricking is conducted by way of staggered maintenance scenario. An alternative approach might have been to examine a staggered maintenance scenario over the entire range of possible spare gasification capacities. A

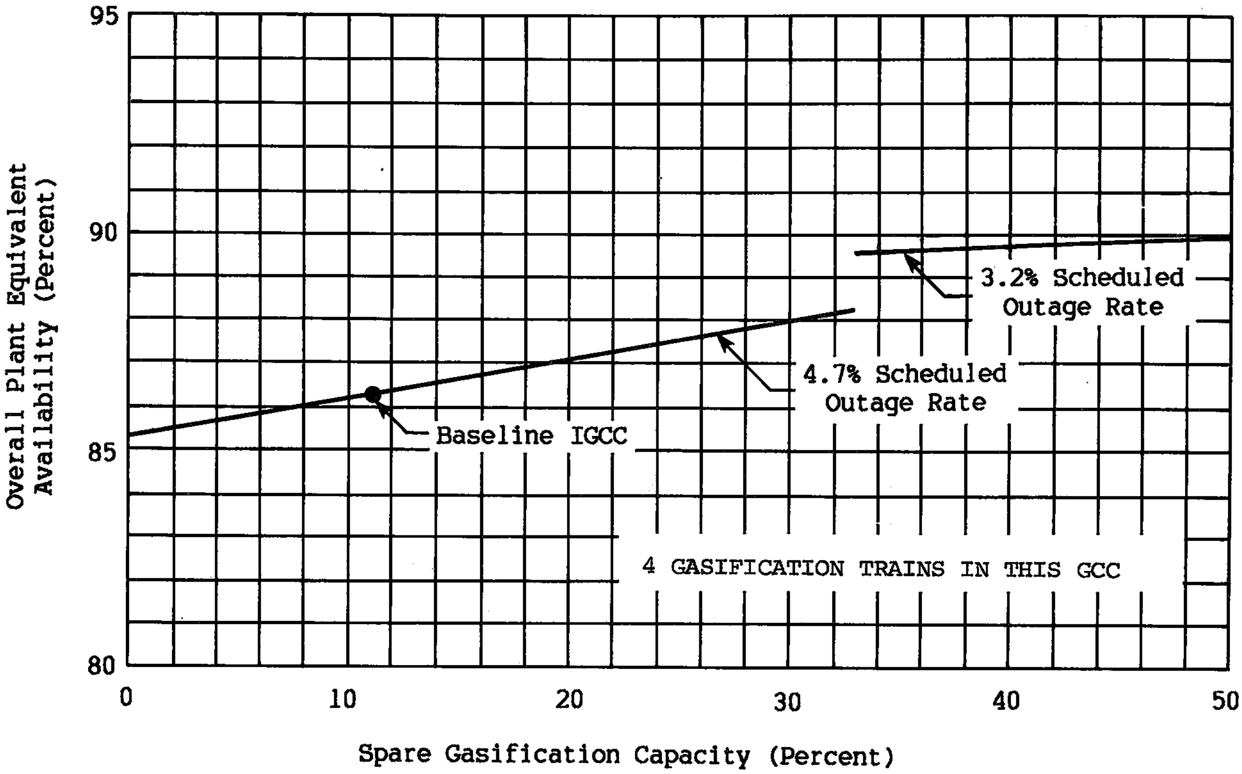


Figure S-1. Impact of Spare Gasification Capacity

graph of this approach, similar to Figure S-1, would not contain any discontinuities since the increase in spare gasification capacity would have a continuous effect on the gasifier-related scheduled outages.

Alternate IGCC Design Basis

There are a number of alternative approaches for designing an IGCC plant. The approach examined in this sensitivity study differs from that of the Baseline IGCC and is of interest to many utilities now evaluating IGCC plants in their resource plans. This alternative design basis consists of a gasification plant that is sized to fully load the combustion turbines with fuel at the 88°F ambient condition. When operated at the 59°F condition, this plant has zero spare gasification capacity and 11.5-percent spare combustion turbine capacity. The equivalent availability result for this design when operated at 59°F ambient is 86.0 percent, which is 0.2 percentage points below the baseline case value.

Alternate Plant Storage Capability

There are a number of locations within an IGCC plant where storage exists. For example, there is a coal pile downstream of the coal-receiving equipment. There is also coal slurry storage and liquid oxygen storage. The capacities of many of these storage points have been established in the EPRI IGCC designs on the basis of industry practice. The purpose of this sensitivity study was to investigate the significance of each storage point and to develop the availability data required in order for IGCC plant designers in the future to perform economic trade-off studies to establish the "optimum" storage capacities.

The storage point with the greatest impact on system availability was the gaseous and liquid oxygen storage. This storage capacity, which amounted to 12 hours of system capacity (or 24 hours of per-train capacity), yielded a 0.6-percentage-point improvement in equivalent availability as opposed to having no storage. The slurry surge tank was also significant because of its potential 0.5-percentage-point impact on plant equivalent availability.

As expected, the impact on plant availability due to changes in storage capacity was greatest at low capacity levels. As the storage capacity increased, an incremental change in capacity yielded a smaller and smaller impact on plant equivalent availability. Figure S-2 shows an example of this relationship. For the majority of storage points designed in the Baseline IGCC plant, the "industry practice" guidelines placed the design storage capacity at the "knee" of the asymptotic curve, which relates equivalent availability to storage capacity. Only an economic analysis can reveal whether these storage capacities are in fact the "optimum" values.

One important consideration to keep in mind when examining the results of these storage calculations is that these storage analyses are only as accurate as the input data. In particular, the estimates of component mean downtime appearing in this report and used in the storage analyses reflect only to varying degrees the estimated plant shutdown and startup time associated with a plant failure. As such, these mean downtime input values are merely estimates, and the resulting storage analysis results are only preliminary.

Optimistic and Pessimistic Gasification Reliability Data

Because of the limited operating experience with mature, commercial coal gasification plants, there is some uncertainty in the reliability and maintainability

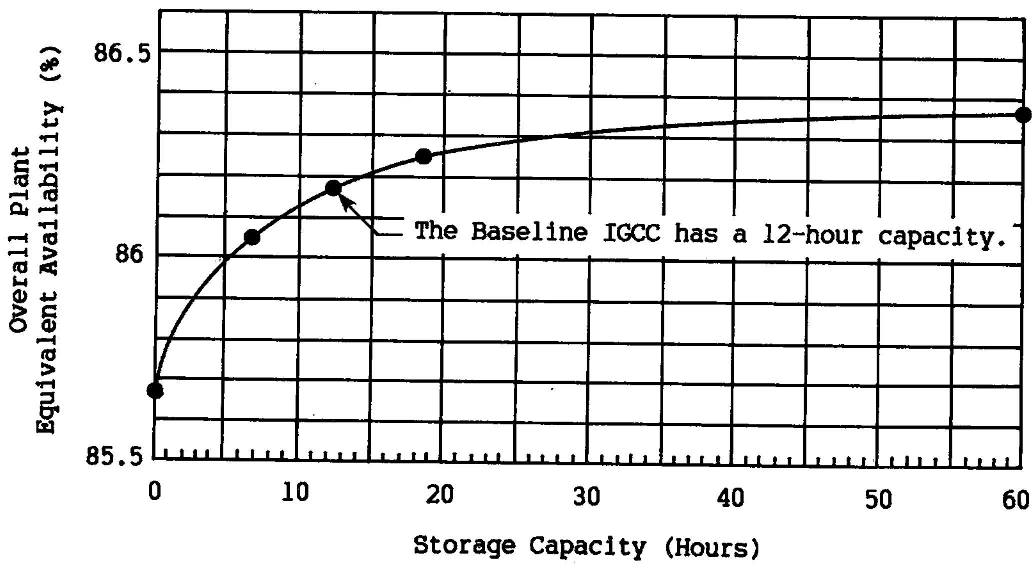


Figure S-2. Slurry Surge Tank System Storage Point

estimates for the gasification section of the IGCC plants. Therefore, a sensitivity study was conducted using optimistic and pessimistic estimates from the gasification process developer, Texaco, Inc. The objective of this study was to capture the range of uncertainty in overall plant availability that is attributable to uncertainty in both the gasification component reliability data and the gasification section scheduled maintenance requirements.

Using the pessimistic reliability data and assuming that scheduled gasifier rebrickings would occur every year (instead of the baseline 1-1/2 year schedule), the overall plant equivalent availability was calculated to be 82.4 percent. This compares with the baseline result of 86.2 percent. When the optimistic component data were used and the baseline gasifier scheduled rebricking interval was employed, the resulting equivalent availability was 87.0 percent.

Alternate Treatment of Tail Gas Treating

In the Baseline IGCC case, one reliability modeling assumption was that the failure of the tail gas treating plant would not cause a plant failure or derating. The ability to flare the tail gas during such a failure mode may not be legally feasible, although it would be technically feasible. If regulatory constraints would force the entire plant to be shut down when the tail gas treating subsystem failed, then the subsequent reduction in the Baseline IGCC equivalent availability would amount to 1.2 percentage points.

SCHEDULED MAINTENANCE PLAN

Recently, EPRI initiated work with Fluor Engineers, Inc. with the objective of developing a scheduled maintenance plan for a multi-train IGCC plant. As a part of the work scope reported here, ARINC Research pursued the schedule development in greater detail. Reasonable estimates of scheduled outage rates such as these are essential to developing accurate measures of overall plant availability.

During the course of the ARINC Research investigation, four factors were identified as the key assumptions affecting a scheduled maintenance plan for IGCC plants. These factors were:

- The assumed length of time required to accomplish each scheduled maintenance activity. A key factor in this determination is the assumption of single- versus double-shift scheduling of maintenance labor.
- The assumed existence or absence of labor and/or spare parts limitations. The existence of such limitations could lead to the need for performing scheduled maintenance in a more time-consuming, staggered fashion.
- The assumed existence or absence of flexibility in the scheduling of equipment maintenance. If there is some flexibility to perform a certain activity within a given time window (as opposed to performing it at exact time intervals), then greater overlap among scheduled maintenance activities can be achieved.
- The assumption regarding the ability to accomplish some scheduled maintenance during forced outages.

A number of scheduled maintenance plans were developed. These plans differ from one another with respect to certain fundamental assumptions. The scheduled outage rate results are summarized in Table S-2.

As can be seen from Table S-2, the scheduled outage rate is quite sensitive to the analysis assumptions. It can vary from 4.7 percent to 8.8 percent. Taking as an example Plans A and B, a change in two assumptions yields a 1.8-percentage point change in the estimated scheduled outage rate. These two plans differ in their estimates of the maintenance activity durations in the combined-cycle section of the IGCC. The ARINC Research estimates of such activities are typically more than twice as great as the Fluor/G.E. estimate in Plan A. These plans also differ in

Table S-2

SCHEDULED MAINTENANCE PLANS

Assumptions	Plan A (Ref. Page B-1)	Plan B (Ref. Table 4-3)	Plan C (Ref. Table 4-6)	Plan D (Ref. Page 4-16)	Plan E (Ref. Table 4-7)
Relative Maintenance Activity Durations	Short	Long	Long	Long	Long
Labor or Spare Parts Limitations	No	No	Yes	No	No
Flexibility in Scheduling Maintenance	Yes	No	No	Yes	No
Any Overlap Between Forced and Scheduled Outages	No	No	No	No	Yes
Source of Estimate	Fluor	ARINC	ARINC	ARINC	ARINC
Scheduled Outage Rate, Percent	4.7	6.5	8.8	5.8	6.0

that the ARINC Research plan assumes there is no flexibility in scheduling maintenance activities, whereas the Fluor plan allows the maintenance to be accelerated or delayed somewhat in order to maximize overlap among closely occurring maintenance activities. Of the 1.8-percentage point difference between the scheduled outage rate estimates in these two plans, 1.2 percent is attributable to the differences in the estimates of scheduled maintenance activity durations.

DISCUSSION

The results presented in this report reflect the best information available today. As more component reliability and maintenance data become available from the Cool Water plant and other sources, these estimates will be improved.

Section 1

INTRODUCTION

As part of the continuing research into IGCC plant design, the Electric Power Research Institute (EPRI) contracted with ARINC Research Corporation to perform availability and efficiency assessments of various design alternatives for an IGCC power plant design. The work was funded under EPRI Research Project 1461-1.

BACKGROUND OF THE PROJECT

The "integrated-gasification-combined-cycle" (IGCC) is a promising new technology for power generation. In IGCCs, the production of syngas is integrated with the highly efficient combined-cycle power generation process. The IGCC design also offers the potential for an environmentally superior process for removing sulfur from coal before combustion. In light of increased social and political pressure to reduce sulfur emission from coal-burning power plants, the IGCC technology is becoming an attractive option for electric utilities.

SCOPE

An IGCC design employing four gasifiers and three combustion turbine/HRSG sets was developed by Fluor Engineers, Inc. in conjunction with Texaco, Inc., General Electric Company, and EPRI and documented in EPRI report AP-3486. EPRI contracted with ARINC Research to perform availability assessments of this design and of various design and operational alternatives specified by EPRI. The work consisted of the evaluation of the availability and the consequent average heat rate impacts of these design and operational alternatives. An economic analysis of the options was not in the scope of the current analysis.

OBJECTIVE OF THE ANALYSIS

The objective of the study was to quantify the availability and the consequent average heat rate impacts associated with several design and operational options. Three baseline cases and five sensitivity studies were specified for analysis. The baseline cases addressed the use of excess gasification capacity for duct firing to the HRSGs and the use of natural gas as a backup for the combustion turbines when portions of the gasification section of the plant were unavailable. The sensitivity studies centered on evaluating changes in unit equivalent availability and average efficiency under the following circumstances:

- Spare gasification capacity is increased.
- The plant is designed at an alternative ambient temperature condition.
- Storage times in the plant are either eliminated, decreased, or increased.
- There is uncertainty in gasification component reliability and maintainability data.
- Environmental regulations are assumed to preclude the ability to flare tail gas when the tail gas treating system is unavailable.

In addition to performing the sensitivity studies, ARINC Research evaluated various scheduled maintenance alternatives, and developed a maintenance plan for the IGCC design under study, using an existing maintenance plan for another IGCC plant design developed by Fluor Engineers, Inc. The evaluation included the following:

- The durations of individual scheduled maintenance actions
- The effect of forced outage shadowing on scheduled outage time
- The total scheduled maintenance requirements for the entire plant.

REPORT ORGANIZATION

Section 2 of this report describes the model used in the analysis. Section 3 presents the results of the analysis, Section 4 presents the IGCC scheduled maintenance plan, and Section 5 presents the study conclusions. Appendix A presents an overview of the UNIRAM methodology. Appendix B is the Fluor Engineers, Inc. scheduled maintenance plan on which the ARINC Research maintenance plan was based. Appendix C is an analytical procedure developed by ARINC Research Corporation for assessing the reductions in scheduled outage days that can be expected when the assumption is made that some scheduled-maintenance-type activities can be accomplished during periods of forced outage. Appendix D describes the principles and the detailed calculations performed to account for plant storage points. Appendix E provides greater detail pertaining to the Fluor estimates of IGCC performance. Appendix F documents the detailed plant configuration represented by each failure mode or plant state. Appendix G presents the principles behind an uncertainty analysis. Appendix H contains a glossary of terms and abbreviations.

Section 2

DESCRIPTION OF THE IGCC MODEL

BASELINE IGCC AVAILABILITY BLOCK DIAGRAM

The IGCC UNIRAM model is an analytical representation of the plant design. It identifies the subsystems required for operation of the unit and quantifies the loss of plant output that occurs with loss of those subsystems. The model consists of basic subsystems that are aggregations of components whose failures have identical impacts on plant operation. Basic subsystems appear in both series and parallel configurations. Failure of a series subsystem will result in failure of the plant. Failure of a parallel subsystem will result in either a derating or the loss of redundancy without a derating. The baseline configuration of the model is illustrated in the availability block diagram (ABD) for the Baseline IGCC, Figure 2-1. The overall process block flow diagram is shown in Figure 2-2.* While the process diagram depicts the flow of coal and gases through the plant, the ABD is a pictorial representation of the "flow" of availability. The ABD includes all subsystems that can affect plant availability. The percentage values above the subsystem blocks in the ABD represent the capacity contributions of each subsystem relative to the maximum plant output. The diamond-shaped markers on the ABD represent the storage points modeled in the analysis.

The plant modeled in Figure 2-1 is a Texaco-based gasification-combined-cycle plant designed with both radiant and convective syngas coolers. (This design is reported in detail in EPRI report AP-3486.) The size of the coal gasification section of the plant was determined by the fuel intake ability of the combustion turbines at a 20°F ambient condition. The availability analysis performed in this study focused on the operation of this plant at a 59°F ambient condition. This difference between the plant's ambient design basis and the ambient temperature basis for the operating performance estimate gives rise to the 11.2-percent spare gasification capacity appearing in Figure 2-1.

*Reproduced from Cost and Performance for Commercial Applications of Texaco-Based Gasification-Combined-Cycle Plants, EPRI report AP-3486, April 1984.

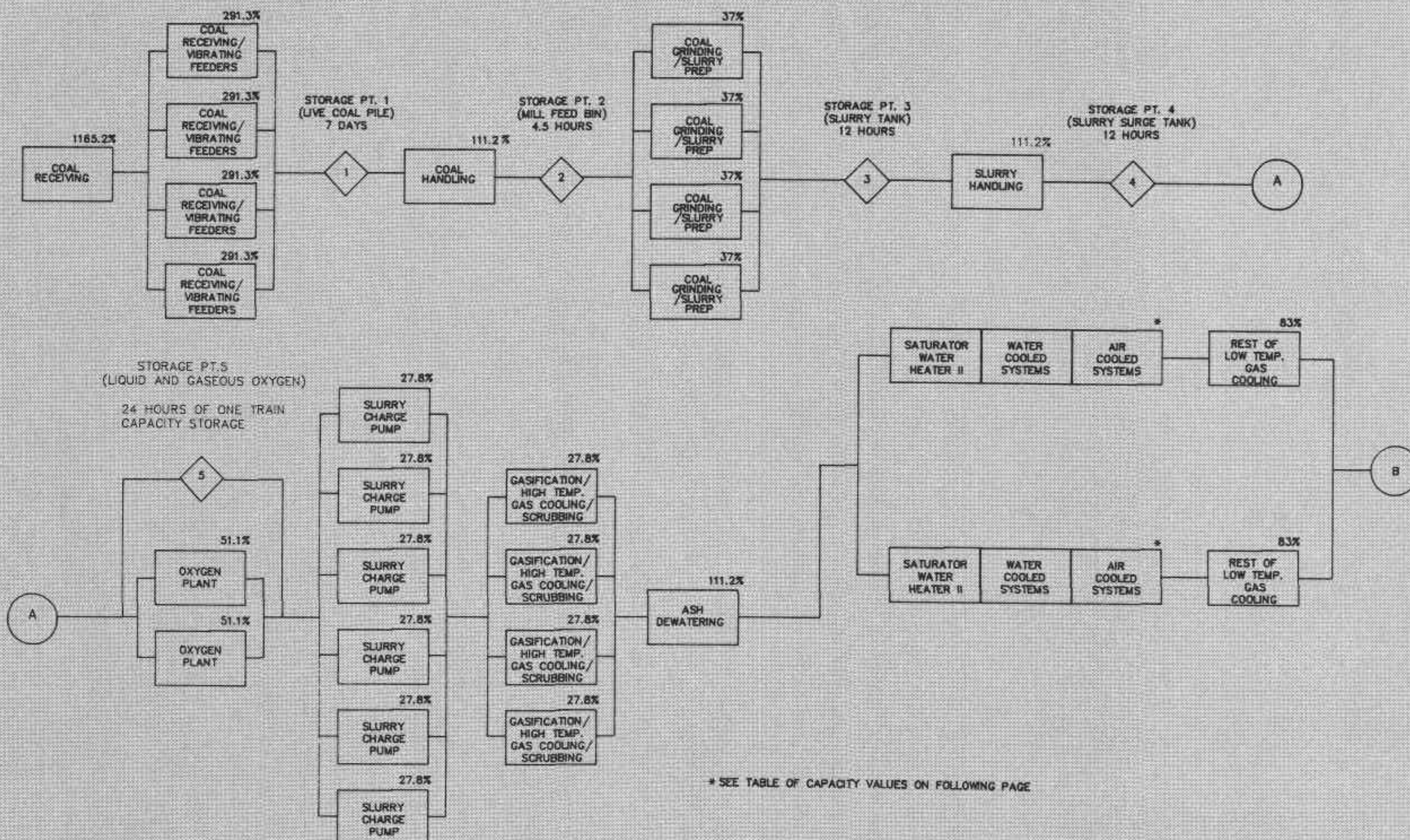
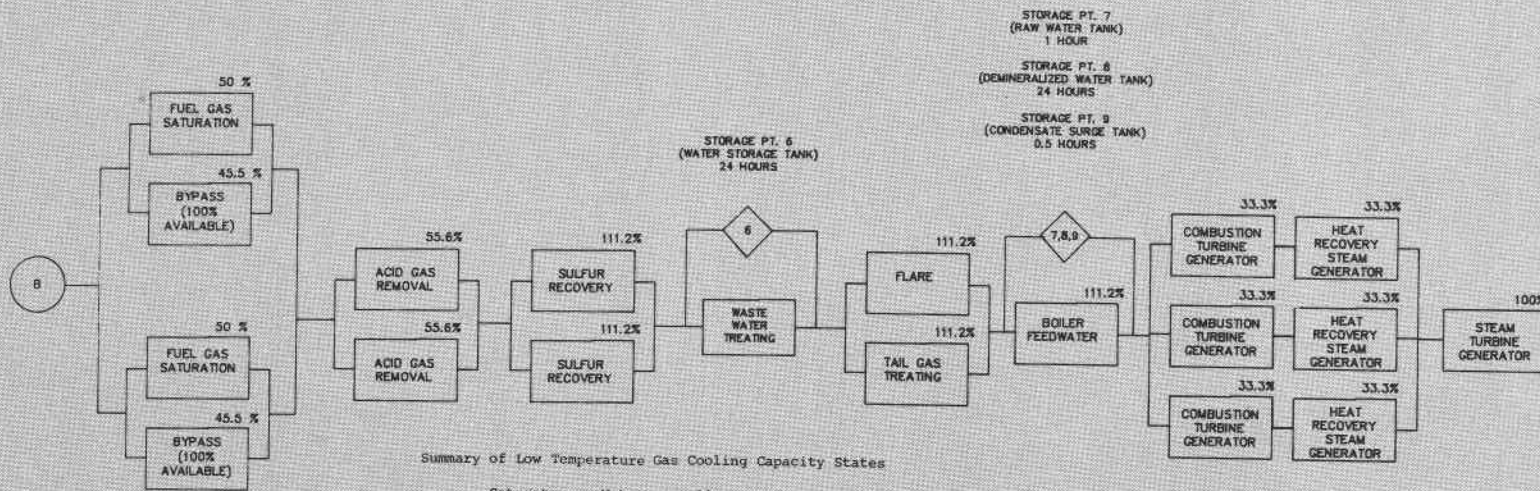


Figure 2-1. Baseline IGCC Availability Block Diagram



Summary of Low Temperature Gas Cooling Capacity States

State	Saturator Water Heater II	Water Cooled Systems	Air Cooled Systems	Capacity
1	0	0	0	83.0%
2	1	0	0	55.6%
3	0	0	1	55.6%
4	0	1	0	27.8%
5	1	1	0	27.8%
6	0	1	1	0.0%
7	1	0	1	0.0%
8	1	1	1	0.0%

0 = subsystem available
1 = subsystem unavailable

Note: The numbers expressed as percentages appearing above each subsystem block represent the capacity of each subsystem as a percent of the total plant capacity.

Figure 2-1. (continued)

The subsystem capacities for the "Coal Receiving" and the "Coal Receiving/Vibrating Feeders" sections also appearing in Figure 2-1 are much higher than the capacities reported for other subsystems. These capacities are very large because coal is unloaded from railroad cars and conveyed to storage piles on an intermittent basis. In fact, in this particular design the equipment is sized to receive more than a three days' supply of coal over a single eight-hour shift. When translated into a subsystem capacity that reflects continuous operation of the equipment, this coal receiving system has a capacity of 1165 percent.

A number of operational assumptions and constraints have been applied to the analysis of this IGCC plant. Many of these assumptions are not apparent from inspection of the availability block diagram. For example, in the Baseline IGCC case an assumption was made that simple-cycle operation of the combustion turbines within the IGCC plant was not possible in the event that the steam turbine failed or that more than one HRSG failed. This operating limitation was evoked since there is a limitation in the capacity of the steam condenser. Simple-cycle operation of the combustion turbines on coal gas would involve substantial flows of saturated steam from the gasification plant. This steam would have to be condensed in the event that either the steam turbine was unavailable or not enough HRSG capacity existed for superheating. Therefore, when potentially insufficient condenser capacity existed, the plant was assumed to be derated or shut down. This assumption also had the effect of simplifying the analysis since it reduced the need for detailed evaluations of some of the low probability operating states.

Another operational assumption involves the ability to flare tail gas in the event of a failure in the tail gas treating section of the plant. While this assumption is valid from the standpoint of technical feasibility, there may be some regulatory restrictions that would disallow the flaring and thus prevent the plant from operating when the tail gas treating subsystem fails. A sensitivity study to address this possibility was performed as a part of the work reported here.

No catastrophic events (such as natural disasters) were in any way accounted for in the analyses described in this report. Furthermore, no account has been made of the possibility of labor strikes which would, in turn, cause extended outages or coal supply disruptions.

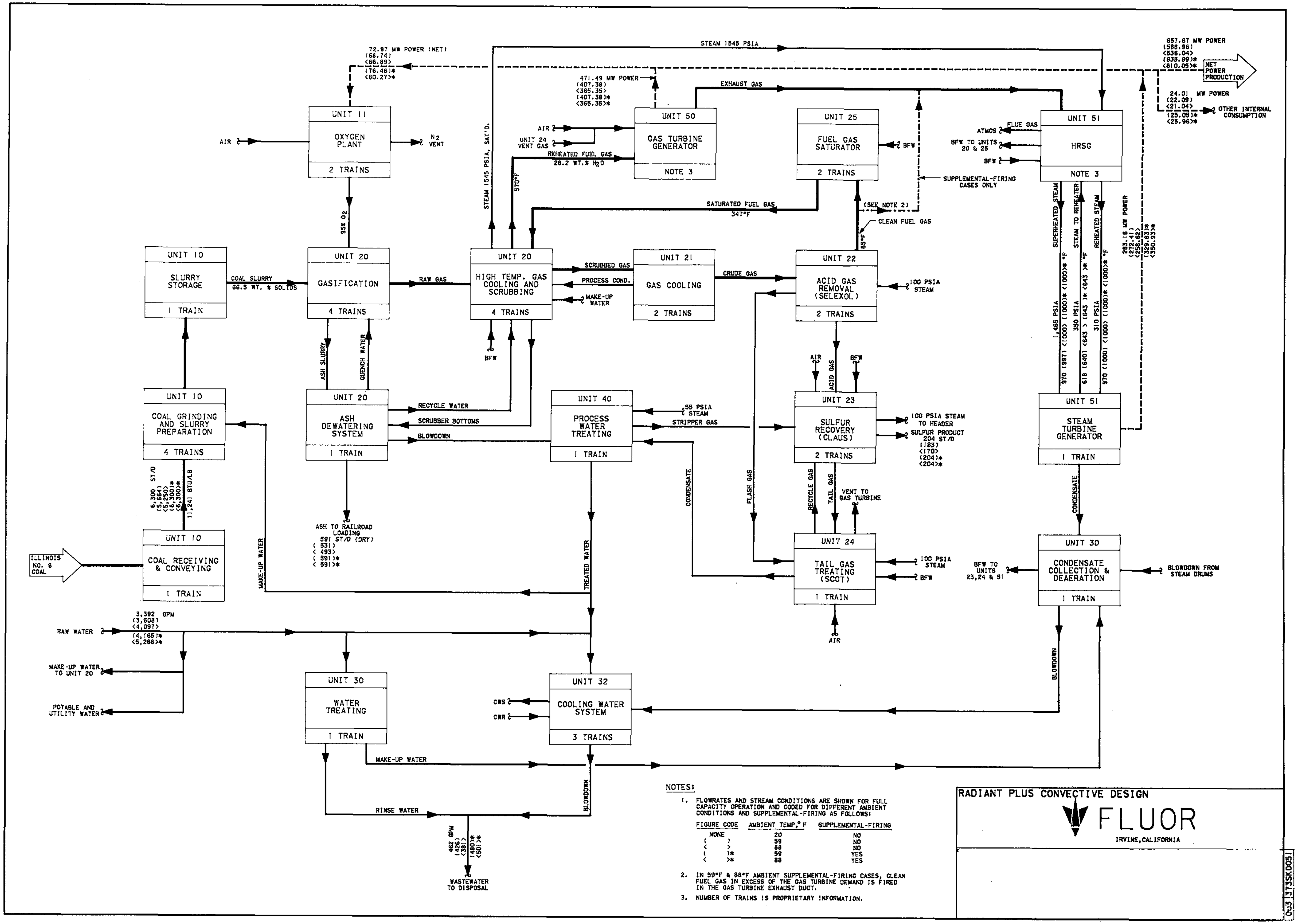


Figure 2-3. Overall Process Block Flow Diagram

Certain equipment within the IGCC plant was removed from the fault tree analyses since it was judged that either this equipment was required only for plant startup or that the failure of this equipment would not by itself cause a plant derating. These "nonessential" equipment items are listed in Table 2-1.

Table 2-1

NONESSENTIAL EQUIPMENT FOR NORMAL OPERATION
THAT WAS EXCLUDED FROM THE FAULT TREES

Plant Section	Equipment Item (Unit Number)
Coal Receiving	Sampling System (10-SA-1)
Coal Grinding/Slurry Prep.	Rod Charger (10-RC-1)
Coal Grinding/Slurry Prep.	Mill Feed Belt Conveyor (10-CV-9)
Gasification through Scrub.	Startup Burner (20-1-ME-3)
Gasification through Scrub.	Startup Aspirator (20-1-EJ-1)
Ash Dewatering	Startup Aspirator K.O. Drum (20-V-4)
Ash Dewatering	Grey Water/Carbon Water Exchanger (20-E-3)
Ash Dewatering	Carbon Water Air Cooler (20-E-4)
Ash Dewatering	Slurry Water Heater (20-E-5)
Ash Dewatering	Flash Gas Cooler (20-E-6)
Ash Dewatering	Make-up Water Heater (20-E-7)
Ash Dewatering	Stacker Reclaimer (20-ME-5)
Ash Dewatering	Area Sump Pump (20-P-6)
Ash Dewatering	Slag Reclaim Conveyor (20-CV-5)
Ash Dewatering	Slag Loading Bin (20-BN-1)
Acid Gas Removal	Hydraulic Turbine (22-1-HT-1)
Ash Dewatering	N_2 Surge Tank (20-TK-7)
Ash Dewatering	Bruner Hoist and Track (20-ME-4)
Ash Dewatering	Soot Blower Gas Compressor (20-C-1)

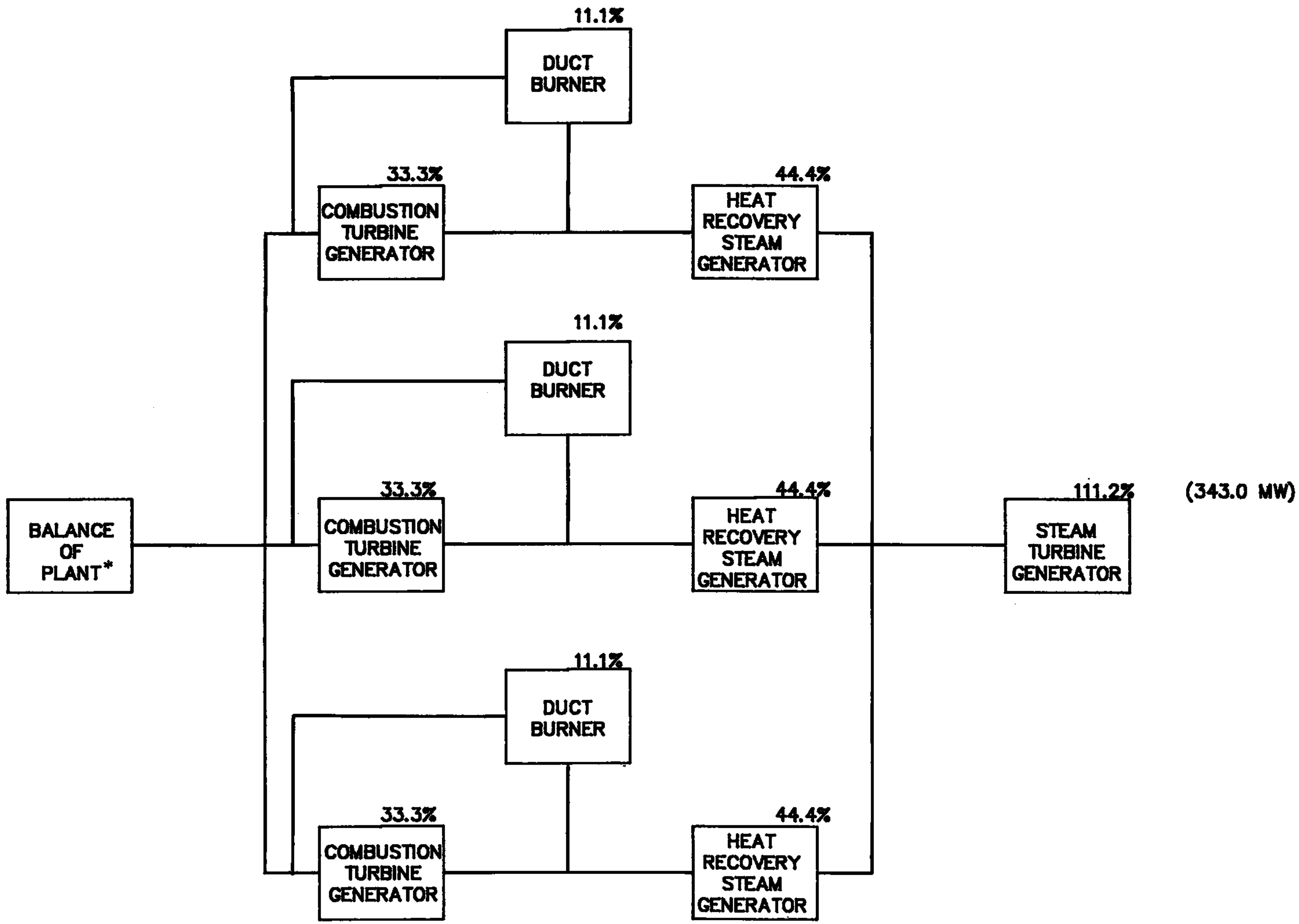
AVAILABILITY BLOCK DIAGRAM FOR THE BASELINE WITH SUPPLEMENTAL FIRING

The Baseline with the Supplemental Firing case is identical in its design to the Baseline IGCC. It differs in its operation only with respect to its use of the excess syngas, producible in the gas plant, for firing the HRSG for the production of supplemental steam.

The ABD for this case is the same as the ABD for the Baseline IGCC with the exception of the combustion turbine/HRSG section of the plant. Figure 2-3 shows the configuration of this section of the plant for the Baseline with Supplemental Firing model. It represents the flow of syngas through this section of the plant. The configuration shown cannot be directly transferred to a data input file for UNIRAM software execution. The increase in capacity represents the increased steam-turbine power output from supplemental firing. It can be seen that loss of all three duct burners or spare gasification capacity brings the net plant MW output down to the same output level as in Baseline IGCC.

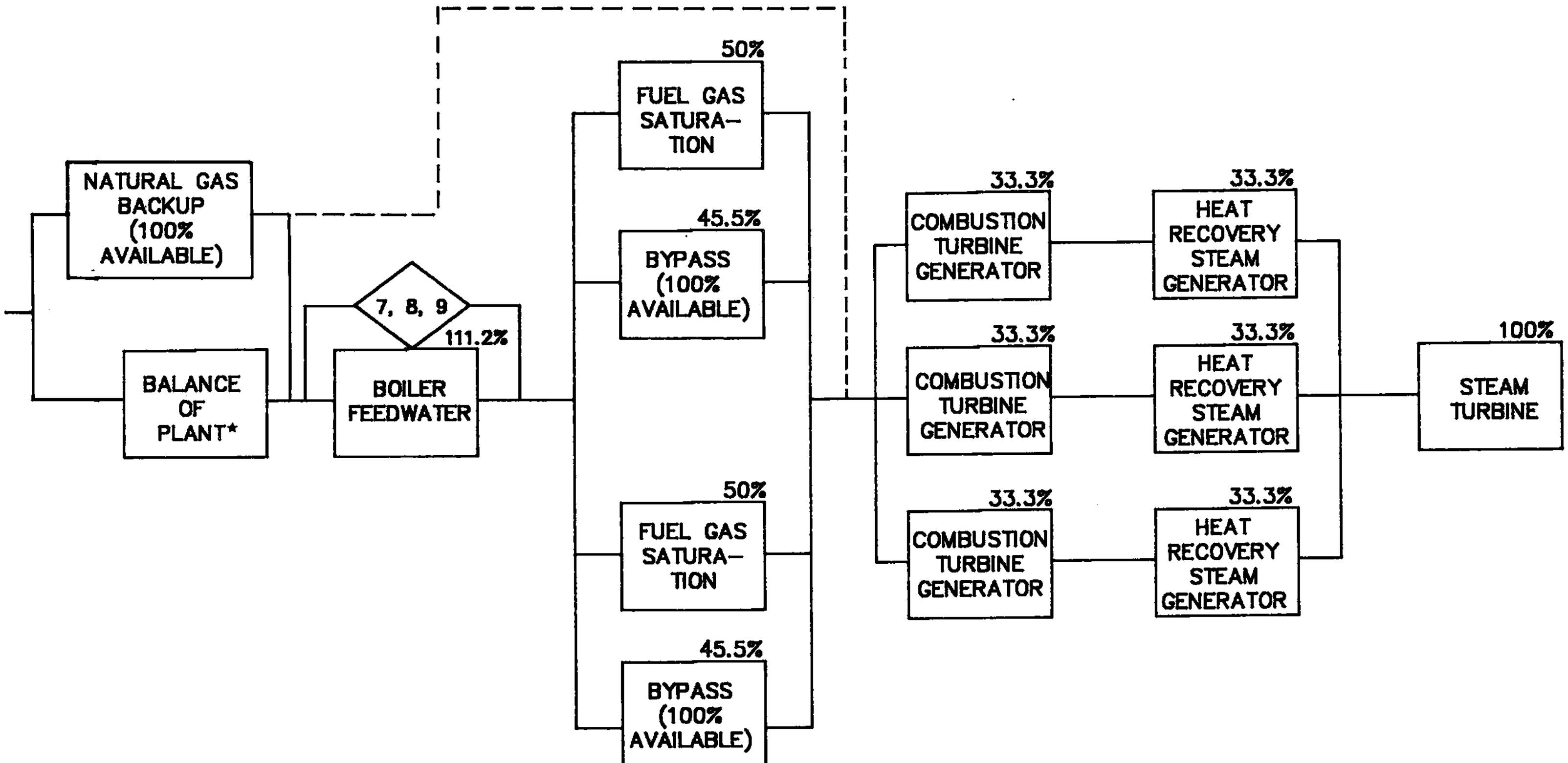
AVAILABILITY BLOCK DIAGRAM FOR THE BASELINE WITH NATURAL GAS BACKUP

In the case of the Baseline with Natural Gas Backup, natural gas is used to fire the combustion turbines when all or a portion of the syngas is unavailable. The design of this plant is identical to that of the Baseline IGCC. The ABD for this case is basically the same as the ABD for the Baseline IGCC except that a perfectly available bypass exists for the coal-receiving-through-gasification section of the plant. In addition, unlike the Baseline IGCC case, the combustion turbines in this case can operate on natural gas in the simple-cycle mode by bypassing the HRSG units in the event of HRSG or steam turbine failure. Figure 2-4 presents the ABD for the plant after incorporating natural gas backup.



*"Balance of Plant" includes all subsystems appearing in Figure 2-1 from "coal receiving" through "boiler feedwater."

Figure 2-3. CT/HRSG/ST Portion of ABD, Baseline with Supplemental Firing



Legend:

– – – THIS PATH FOR THE NATURAL GAS IS EMPLOYED ONLY WHEN THE ENTIRE GASIFICATION PLANT OR THE FUEL GAS SATURATION SYSTEM IS NOT OPERATIVE.

*"Balance of Plant" includes all subsystems appearing in Figure 2–1 from "coal receiving" through "tail gas treating."

Figure 2-4. ABD for Baseline with Natural Gas Backup

MODEL PREPARATION

The model was prepared by first identifying basic subsystems that have the potential for affecting plant availability in the IGCC process flow diagrams (PFDs) and system descriptions. EPRI, Fluor Engineers, Inc., and Texaco, Inc. provided technical guidance and reviewed all model details. Twenty-five basic subsystems were defined for the model.

The model was completed by identifying the components within each subsystem that could cause subsystem failure by failing individually or in conjunction with other components. Components are organized into fault trees. Fault trees logically define the failure modes of the basic subsystem in terms of its components. A component is defined as the lowest level of equipment for which data are available. For example, the acid gas removal subsystem includes pump and motor components under each lean-solution pump block. In the case of the heat recovery steam generator subsystem, less detailed equipment reliability information is available and as a result all components contained in the HRSGs are included in a single block in the fault tree.

Within the ABD and the fault trees, a common constraint applies to component or basic subsystem capacity. Both components and basic subsystems are defined as having only two operating states, failed or operating. The UNIRAM methodology does not incorporate a provision for degraded operation of components. The methodology does permit evaluation of degraded states by employing parallel subsystems with different capacities.

Each fault tree includes components and gates. OR gates ( ) are used to indicate components whose failure will result in subsystem failure. AND gates ( ) indicate components whose failures must be concurrent with all other component failures under the gate for subsystem failure to occur. If components A and B are located under an AND gate, both A and B must fail simultaneously for the subsystem to fail. Under an OR gate, failure of either A or B or both will cause subsystem failure.

STORAGE POINT RELIABILITY IMPACTS

A number of storage points have been modeled in the IGCC plant design. Storage points are identified by diamond-shaped markers on the ABD. If a storage point affects subsystems upstream from it, the marker is placed in series downstream of the first subsystem it affects. If a storage point affects only one subsystem and no subsystems upstream of it, it is shown in parallel with the subsystem it affects. Table 2-2 lists all storage points.

Table 2-2

STORAGE POINT DESCRIPTION

Storage Point	Description	Capacity (Hours)
1	Live Coal Pile	168.0
2	Mill Feed Bin	4.5
3	Slurry Tank	12.0
4	Slurry Surge Tank	12.0
5	Liquid and Gaseous Oxygen	24.0
6	Water Storage Tank	24.0
7	Raw Water Tank	1.0
8	Demineralized Water Tank	24.0
9	Condensate Surge Tank	0.5

A major difference between former availability analyses performed for EPRI and this IGCC plant availability analysis lies in the accounting for the RAM impacts of storage. For example, the slurry surge tank in Figure 2-2 can store enough slurry to permit the plant to operate for 12 hours in the event of a failure upstream of the slurry surge tank, e.g., a failure of the upstream reclaim conveyor 10-CV-4B. If no storage points are modeled, the failure of this reclaim conveyor will cause an immediate plant shutdown. Consequently, in this example the proper handling of storage will result in a shutdown of the IGCC plant only if the downtime of the reclaim conveyor exceeds 28.5 hours (28.5 hours includes the effects not only of the 24-hour surge tank but of all other storage points affecting the reclaim conveyor). In this case, the value of 28.5 hours is derived as follows:

Total Storage Capacity Impacting Reclaim Conveyor = Capacity of Storage Point 4 + Capacity of Storage Point 3 + Capacity of Storage Point 2

= 12 + 12 + 4.5

= 28.5 hours

The addition of storage points to a process has the effect of masking failures of upstream components. The masking causes the "effective" component mean time between failures (MTBF) to increase from the actual value. The change in component MTBF has a significant overall impact on plant availability measures. One sensitivity study addressed in Section 3 of this report quantifies this impact. The change in the MTBF value is a function of expected storage capacities, rates of flow into and out of storage points, and the maximum capacity of the storage point.

ARINC Research Corporation developed a methodology for evaluating the effect of storage capacity on the reliability characteristics of power systems. This methodology was applied to evaluate storage effects on the IGCC plant and component reliability measures. All storage points are assumed to be fully recharged at the time of any failure. A detailed description of this methodology can be found in Appendix D.

FAULT TREE DESCRIPTIONS

The remainder of this chapter addresses the individual subsystems in the model, presenting technical descriptions of the subsystems and identifying any assumptions made in preparing the fault tree. The technical descriptions were obtained in part from the Fluor Engineers.

All of the reliability and maintainability estimates appearing in the following tables and fault trees were derived either directly from Texaco and Fluor or from a former study performed by ARINC Research and Fluor which was published by EPRI under report AP-2202. In this earlier study, estimates were developed based on the consensus of experts.

Coal Receiving

The coal receiving subsystem encompasses the areas of the plant from initial coal unloading through stacker boom conveyors 10-CV-8A and B. The components modeled and their reliability and maintainability values are shown in Table 2-3. The fault tree representation for the subsystem is shown in Figure 2-5. All components in this subsystem are modeled under an OR gate, with the exception of the two stacker boom conveyors. Both stacker boom conveyors have been modeled under an AND gate, indicating that both stacker boom conveyors must fail in order to cause a failure of the coal receiving subsystem. A failure of any other component in the subsystem will cause a failure of the subsystem. For example, if receiving conveyor 10-CV-1 fails, the coal supply to the downstream process would be interrupted, causing

Table 2-3

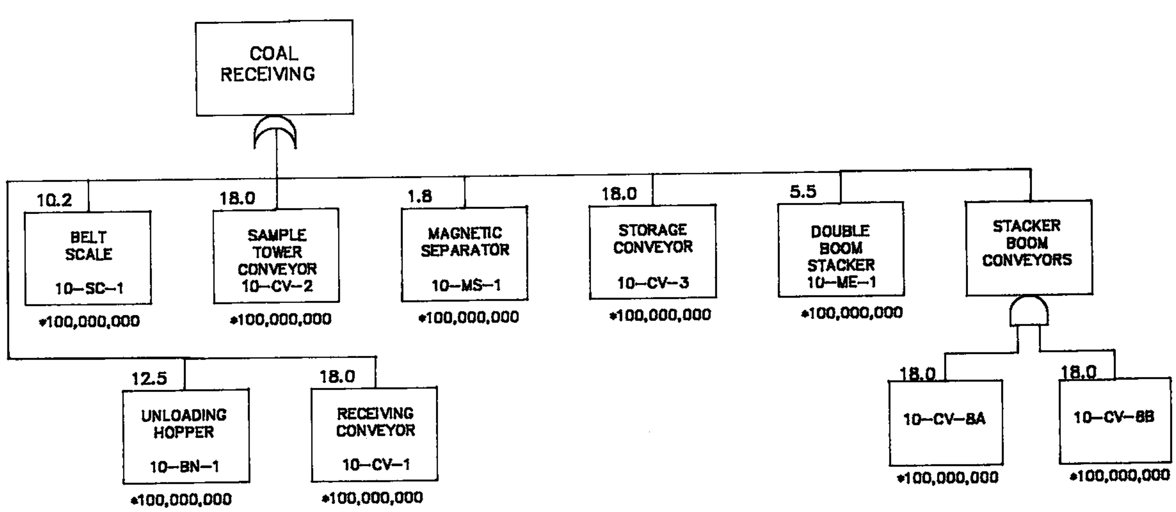
COAL RECEIVING COMPONENT DATA

Component Number	Component Name	Inherent Component Data: MTBF (Hours)	Inherent Component Data: MDT (Hours)	Impacting Storage Points*	Storage Time (Hours)	Component Data After Accounting for Storage: MTBF (Hours)	Component Data After Accounting for Storage: MDT (Hours)
10-BN-1	Unloading Hopper	9,986	12.5	1,2,3,4	196.5	100,000,000	12.5
10-CV-1	Receiving Conveyor	17,520	18.0	1,2,3,4	196.5	100,000,000	18.0
10-SC-1	Belt Scale	26,280	10.2	1,2,3,4	196.5	100,000,000	10.2
10-CV-2	Sample Tower Conveyor	17,520	18.0	1,2,3,4	196.5	100,000,000	18.0
10-MS-1	Magnetic Separator	87,600	1.8	1,2,3,4	196.5	100,000,000	1.8
10-ME-1	Double Boom Stacker	17,520	5.5	1,2,3,4	196.5	100,000,000	5.5
10-CV-3	Storage Conveyor	17,520	18.0	1,2,3,4	196.5	100,000,000	18.0
10-CV-8A	Stacker Boom Conveyor	17,520	18.0	1,2,3,4	196.5	100,000,000	18.0
10-CV-8B	Stacker Boom Conveyor	17,520	18.0	1,2,3,4	196.5	100,000,000	18.0

*Storage points downstream of a component can affect the reliability and maintainability of a component as it is perceived by the downstream equipment. These points are identified on the Availability Block Diagram.

SUBSYSTEM AVAILABILITY

IN THE ABSENCE OF STORAGE = 99.495%
AFTER ACCOUNTING FOR STORAGE = 100.000%



*AFFECTED BY STORAGE. RELIABILITY AND MAINTAINABILITY DATA FOR THIS EQUIPMENT BOTH WITH AND WITHOUT CONSIDERATION OF DOWNSTREAM STORAGE CAN BE FOUND ON TABLE 2-3.

Figure 2-5. Coal Receiving Fault Tree

a shutdown of the plant, if all downstream storage points, such as the two 3.5-day live storage piles, are exhausted. Four storage points directly affect the perceived reliability of the coal receiving system:

- Storage Point 1 (live coal pile)
- Storage Point 2 (mill feed bin)
- Storage Point 3 (slurry tank)
- Storage Point 4 (slurry surge tank)

The assumptions have been made that the expected values of the storage points in series with each other are additive, and all storage points are completely full at the time of the upstream equipment failure. Thus, if receiving conveyor 10-CV-1 fails, storage points 1 through 4 will have to be exhausted before the plant must shut down. This same assumption applies to all components in the coal receiving system. Only component failures with downtimes in excess of the total impacting-storage-point time will have an effect on plant availability. The presence of substantial downstream storage makes the coal receiving subsystem essentially perfectly available from the perspective of its impact on overall plant availability. This high availability is evidenced in Table 2-3 by the high mean time between failures indicated by those estimates that incorporate the effect of storage on the components.

<u>Vibrating Feeders</u>

Vibrating feeders 10-FE-1A through D withdraw coal from the unloading hopper (10-BN-1) and place it onto receiving conveyor 10-CV-1. Vibrating feeders, as modeled in this subsystem, are shown with the reliability and maintainablity values in Table 2-4. The fault tree for this subsystem is shown in Figure 2-6.

Table 2-4

COAL RECEIVING/VIBRATING FEEDERS COMPONENT DATA

Component Number	Component Name	Inherent Component Data MTBF (Hours)	Inherent Component Data MDT (Hours)	Impacting Storage Point*	Storage Time (Hours)	Component Data After Accounting for Storage MTBF (Hours)	Component Data After Accounting for Storage MDT (Hours)
10-FE-1	Vibrating Feeders	17,520	2.8	1,2,3,4	196.5	100,000,000	2.8

*Storage points downstream of a component can affect the reliability and maintainability of a component as it is perceived by the downstream equipment. These points are identified on the Availability Block Diagram.

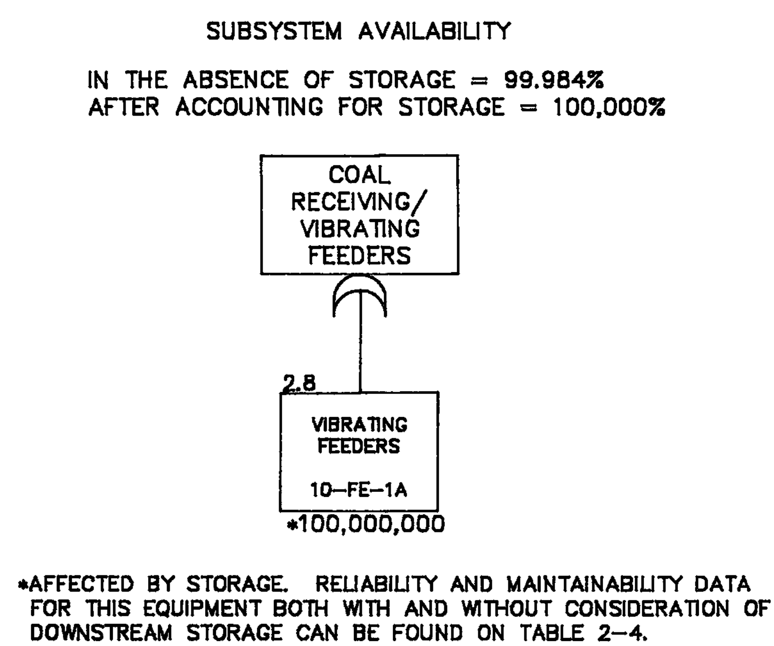


Figure 2-6. Coal Receiving/Vibrating Feeders Fault Tree

Coal Handling

The coal handling subsystem includes the sections of the plant from bucket wheel reclaimer 10-ME-2 through belt conveyor 10-CV-7. Coal is reclaimed from the two 3.5-day storage piles by the bridge-type bucket wheel reclaimer. The reclaimer is moved between the live storage piles by transfer car 10-TC-1. The bucket wheel moves across the face of the pile, making an angle-of-repose cut across the layers of coal, thereby blending the coal fed to the gasification plant. This blending facilitates more uniform gasifier operation. Reclaimed coal is carried on the bucket wheel conveyor to one of the two reclaim conveyors, 10-CV-4A and B. When 10-CV-4A is in service, cross conveyor 10-CV-5 is used to deliver coal to transfer conveyor 10-CV-6 through the use of reclaim conveyor 10-CV-4B. Reclaim conveyor 10-CV-4A and cross conveyor 10-CV-5 were not included in the availability assessment model, because the failure of either one will not affect plant availability. The coal feed process in this section of the plant is dependent on reclaim conveyor 10-CV-4B.

Figure 2-7 is the fault tree for the coal handling subsystem. All components are modeled under a common OR gate. Thus if any component in the subsystem fails, the subsystem itself will fail, resulting in a plant shutdown. Table 2-5 lists the components in the subsystem, their reliability and maintainability values, and the storage points affecting the various components.

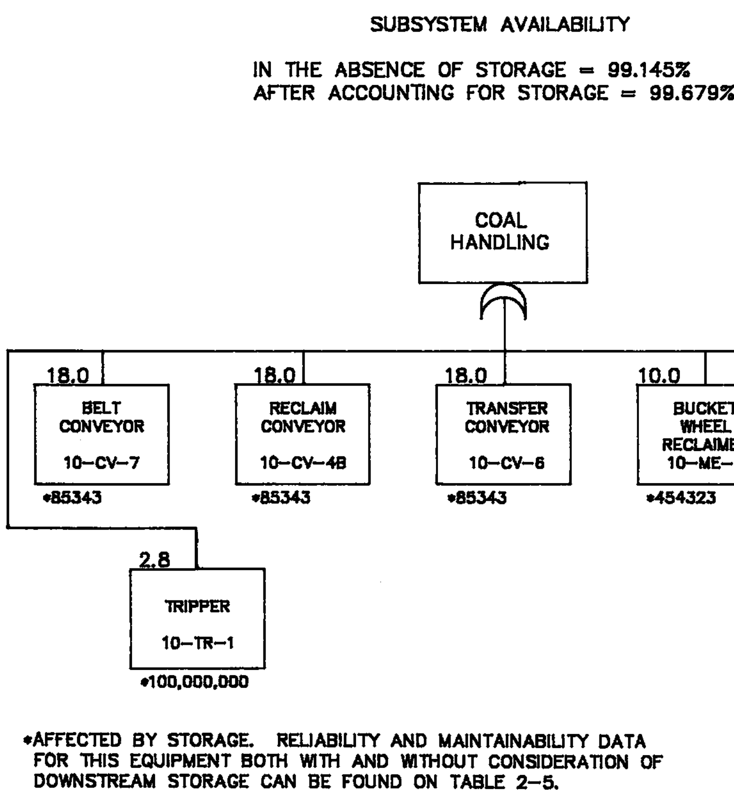


Figure 2-7. Coal Handling Fault Tree

Table 2-5

COAL HANDLING COMPONENT DATA

Component Number	Component Name	Inherent Component Data MTBF (Hours)	Inherent Component Data MDT (Hours)	Impacting Storage Points*	Storage Time (Hours)	Component Data After Accounting for Storage MTBF (Hours)	Component Data After Accounting for Storage MDT (Hours)
10-TR-1	Tripper	43,800	2.8	2,3,4	28.5	100,000,000	2.8
10-CV-7	Belt Conveyor	17,520	18.0	2,3,4	28.5	85,343	18.0
10-CV-6	Transfer Conveyor	17,520	18.0	2,3,4	28.5	85,343	18.0
10-ME-2	Bucket Wheel Reclaimer	26,280	10.0	2,3,4	28.5	454,323	10.0
10-TC-1	Transfer Car	43,800	3.7	2,3,4	28.5	100,000,000	3.7
10-MD-1	Metal Detector	43,800	1.8	2,3,4	28.5	100,000,000	1.8
10-ME-6	Dust Suppression System	8,760	43.3	2,3,4	28.5	16,918	43.3
10-CV-4B	Reclaim Conveyor	17,520	18.0	2,3,4	28.5	85,343	18.0

*Storage points downstream of a component can affect the reliability and maintainability of a component as it is perceived by the downstream equipment. These points are identified on the Availability Block Diagram.

Coal Grinding and Slurry Preparation

The coal grinding and slurry preparation subsystem encompasses the section of the coal feed process from the vibrating feeders to the mill slurry sump pumps. Coal from the vibrating feeders is fed to rod mill 10-MR-1 from weigh belt feeder 10-FW-1. The rod mill crushes the coal and feeds the coal slurry to the mill slurry sump with agitator 10-SP-1. The coal slurry is then pumped to the slurry storage subsystem.

The components in the coal handling subsystem, their reliability and maintainability values, and impacting storage points are shown in Table 2-6. Figure 2-8 is the fault tree representation of this subsystem. All components are modeled under a common OR gate with the exception of the mill slurry pumps, which are modeled under an AND gate. Thus both mill slurry pumps must fail simultaneously in order to cause a subsystem failure.

Slurry Handling

The slurry handling subsystem includes the slurry holding tank with mixer, slurry surge tank with mixer, and slurry transfer booster pumps. Components modeled are listed in Table 2-7. Figure 2-9 is the fault tree for the subsystem. All components have been modeled under a common OR gate with the exception of the transfer and booster pumps, which are modeled under AND gates.

Table 2-6

COAL GRINDING/SLURRY PREPARATION COMPONENT DATA

Component Number	Component Name	Inherent Component Data MTBF (Hours)	Inherent Component Data MDT (Hours)	Impacting Storage Points*	Storage Time (Hours)	Component Data After Accounting for Storage MTBF (Hours)	Component Data After Accounting for Storage MDT (Hours)
10-BN-2	Mill Feed Bin	91,104.0	11.0	3,4	24.0	807,401	11.0
10-FE-2	Vibrating Bin Bottoms	17,520.0	3.0	3,4	24.0	52,226,384	3.0
10-FW-1	Weigh Belt Feeder	17,520.0	7.0	3,4	24.0	540,187	7.0
10-MR-1	Rod Mill	486.7	1.5	3,4	24.0	100,000,000	1.5
10-SP-1	Mill Slurry Sump with Agitator	47,304.0	7.5	3,4	24.0	1,160,487	7.5
10-P-1-1	Mill Slurry Pump	8,760.0	83.0	None			
10-P-1-2	Mill Slurry Pump	8,760.0	83.0	None			

*Storage points downstream of a component can affect the reliability and maintainability of a component as it is perceived by the downstream equipment. These points are identified on the Availability Block Diagram.

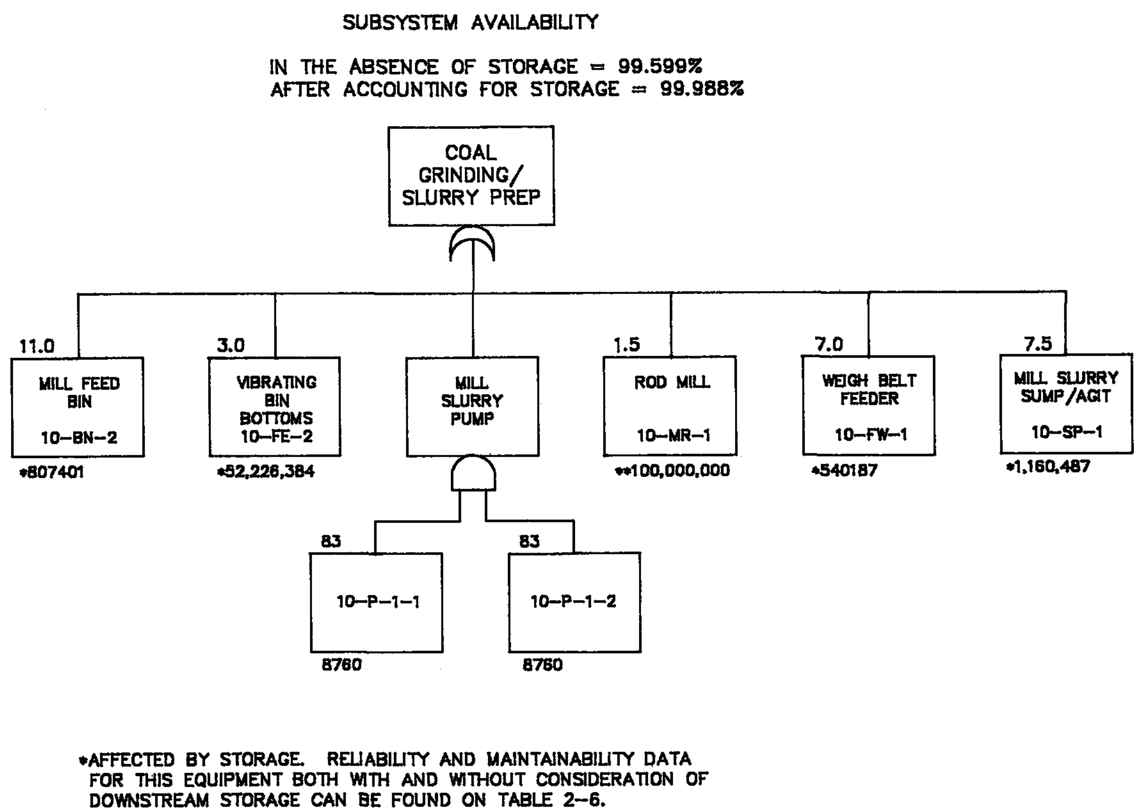


Figure 2-8. Coal Grinding/Slurry Preparation Fault Tree

Table 2-7

SLURRY HANDLING COMPONENT DATA

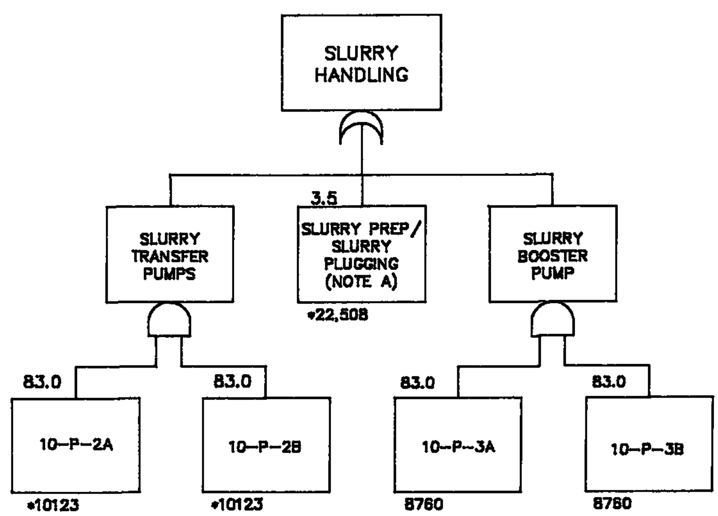
Component Number	Component Name	Inherent Component Data MTBF (Hours)	Inherent Component Data MDT (Hours)	Impacting Storage Points*	Storage Time (Hours)	Component Data After Accounting for Storage MTBF (Hours)	Component Data After Accounting for Storage MDT (Hours)
10-P-2A	Slurry Transfer Pump	8,760	83.0	4	12.0	10,123	83.0
10-P-2B	Slurry Transfer Pump	8,760	83.0	4	12.0	10,123	83.0
10-P-3A	Slurry Booster Pump	8,760	83.0	None			
10-P-3B	Slurry Booster Pump	8,760	83.0	None			
N/A	Slurry Prep/Slurry Plugging**	730	3.5	4	12.0	22,508	3.5

*Storage points downstream of a component can affect the reliability and maintainability of a component as it is perceived by the downstream equipment. These points are identified on the Availability Block Diagram.

**Includes Holding Tank Mixer (10-MX-1), Slurry Holding Tank (10-TK-1), Slurry Surge Tank with Mixer (10-TK-2), and associated piping.

SUBSYSTEM AVAILABILITY

IN THE ABSENCE OF STORAGE = 99.505%
AFTER ACCOUNTING FOR STORAGE = 99.968%



•AFFECTED BY STORAGE. RELIABILITY AND MAINTAINABILITY DATA FOR THIS EQUIPMENT BOTH WITH AND WITHOUT CONSIDERATION OF DOWNSTREAM STORAGE CAN BE FOUND ON TABLE 2-7.

NOTE A: THIS INCLUDES HOLDING TANK MIXER (10-MX-1), SLURRY HOLDING TANK (10-TK-1), SLURRY SURGE TANK WITH MIXER (10-TK-2), AND ASSOCIATED PIPING.

Figure 2-9. Slurry Handling Fault Tree

Oxygen Plant

The oxygen plant subsystem is modeled by a single component block, which represents the aggregate of all component failures in the subsystem. The reliability and maintainability data used for the oxygen plant were taken principally from data compiled by Air Products and Chemicals, Inc. Using these data and assuming exponential failure and repair distributions, ARINC Research calculated an effective mean downtime and mean time between failures based on a 24-hour storage capacity for the system (based on the storage capacity of one 51.1-percent capacity train). The reliability and maintainability data used to develop the failure distribution are shown in Table 2-8.

Table 2-8

OXYGEN PLANT RELIABILITY AND MAINTAINABILITY DATA*

Duration of Forced Outages (Hours)	Lost Production (Days/Year)	Frequency (Outages/Year)
0 - 6 Hours	0.5	4
6 - 24 Hours	1.5	3
24 - 72 Hours	1.0	0.8
Total	3.0	7.8

*Source: W. J. Scharle and K. Wilson, Air Products and Chemicals, Inc., "Oxygen Facilities for Synthetic Fuel Projects," ASME Cryogenic Processes and Equipment Conference, San Francisco, August 1980.

From the information presented in Table 2-8, ARINC Research made the following conclusions:

- Four out of the 7.8 forced outages per year result in downtimes of 6 hours or less.
- Seven out of the 7.8 forced outages per year result in downtimes of 24 hours or less.
- All of the forced outages per year result in downtimes of 72 hours or less.

This information was translated into a cumulative plot for the oxygen plant downtimes, as shown in Figure 2-10.

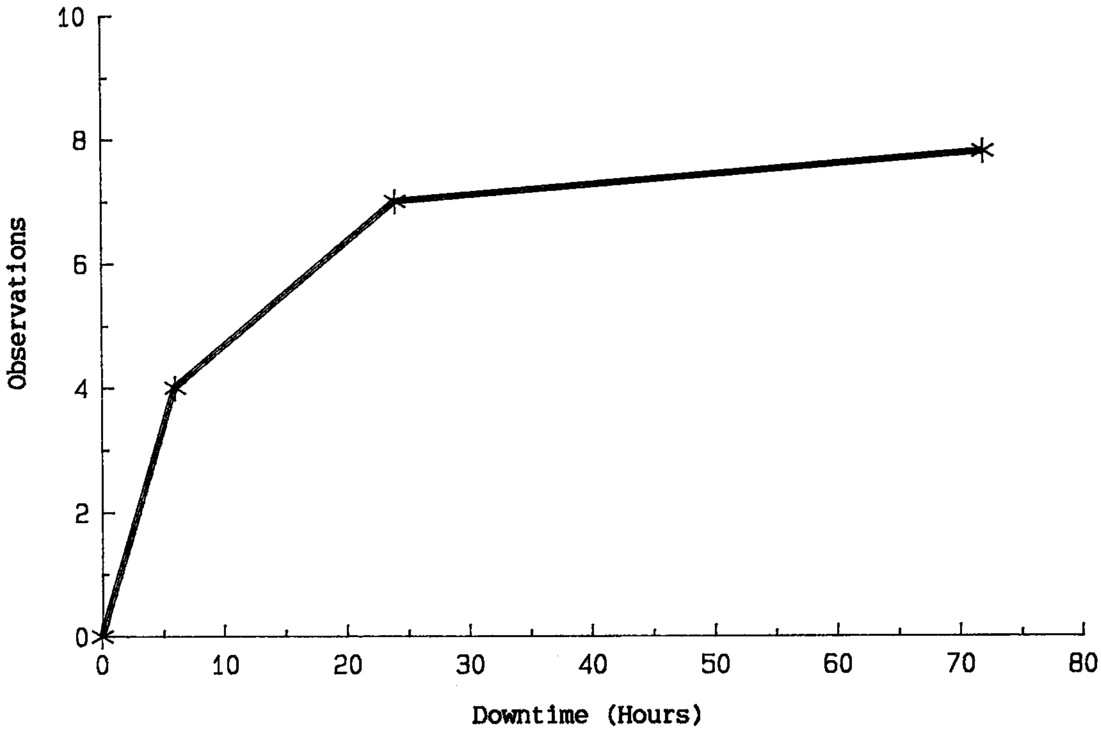


Figure 2-10. Oxygen Plant Cumulative Failure Function

The probability that a failure of the oxygen plant will exceed 24 hours, using the Table 2-8 frequency data, is indicated by:

$$P(\text{downtime} > 24 \text{ hours}) = 1 - P(\text{downtime} < 24 \text{ hours})$$

The probability of a failure causing a downtime less than 24 hours would be the number of failures per year causing downtimes of less than 24 hours divided by the total number of outages per year, or 7/7.8.

$$= 1 - (7/7.8)$$
$$= 0.1026$$

To utilize the ARINC Research storage algorithm, the assumption must be made that failures of the oxygen plant conform to an exponential distribution. An exponential distribution implies a constant failure and repair rate for oxygen plant failures. Knowing the probability of a failure causing a downtime in excess of 24 hours, the mean downtime based on an exponential distribution can be calculated.

$$P(\text{downtime} > 24 \text{ hours}) = \mu \int_{24}^{\infty} e^{-\mu t} dt$$

where,

μ = inverse of mean downtime (MDT), hours^{-1}
t = time, hours

Solving for μ, we obtain:

$$e^{-\mu 24} = 0.1026$$

$$-\mu(24) = \ln (0.1026)$$

$$\mu = 0.0949$$

Since, mean downtime (MDT) $= \dfrac{1}{\mu}$

$$\text{MDT} = 10.5 \text{ hours}$$

The mean downtime (MDT) of 10.5 hours is the MDT of the oxygen plant. The mean time between failure of the oxygen plant is approximated by the inverse of the total frequency of outages per year or

$$\text{Mean time between failure (MTBF)} = \frac{1\text{ year}}{7.8\text{ outages}} \times \frac{8,760\text{ hours}}{1\text{ year}}$$

$$= 1,123\text{ hours between outages}$$

Using the ARINC Research storage algorithm, the effective mean downtime (MDT) and mean time between failure (MTBF), on the basis of a 24-hour oxygen plant storage capacity, was 10.5 hours and 11,042 hours, respectively.

Table 2-9 lists the components modeled in the oxygen plant subsystem. Figure 2-11 is the fault tree representation of the system.

Table 2-9

OXYGEN PLANT COMPONENT DATA

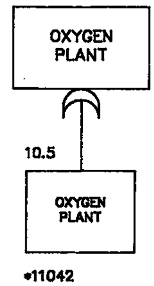
		Inherent Component Data				Component Data After Accounting for Storage	
Component Number	Component Name	MTBF (Hours)	MDT (Hours)	Impacting Storage Points*	Storage Time (Hours)	MTBF (Hours)	MDT (Hours)
N/A	Oxygen Plant	1,123	10.5	5	24**	11,042	10.5

*Storage points downstream of a component can affect the reliability and maintainability of a component as it is perceived by the downstream equipment. These points are identified on the Availability Block Diagram.

**The assumption in developing the storage-affected component data is that only one oxygen plant train (out of two) fails at any given time. Consequently, the entire 24 hours of storage capacity is available for use by that train.

SUBSYSTEM AVAILABILITY

IN THE ABSENCE OF STORAGE = 99.074%
AFTER ACCOUNTING FOR STORAGE = 99.905%



*AFFECTED BY STORAGE. RELIABILITY AND MAINTAINABILITY DATA FOR THIS EQUIPMENT BOTH WITH AND WITHOUT CONSIDERATION OF DOWNSTREAM STORAGE CAN BE FOUND ON TABLE 2-9.

Figure 2-11. Oxygen Plant Fault Tree

Slurry Charge Pumps

Coal slurry from the slurry handling subsystem is delivered to the gasifier burners by the slurry charge pumps 20-P-1. The slurry charge pump subsystem fault tree is shown in Figure 2-12. Table 2-10 is the component list for the subsystem. Six pumps in parallel have been modeled in the plant.

SUBSYSTEM AVAILABILITY = 99.886%

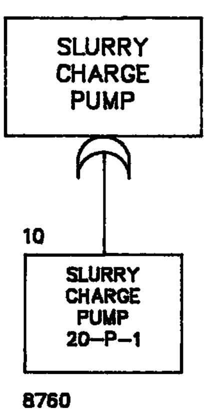


Figure 2-12. Slurry Charge Pump Fault Tree

Table 2-10

SLURRY CHARGE PUMP COMPONENT DATA

Component Number	Component Name	Inherent Component Data MTBF (Hours)	Inherent Component Data MDT (Hours)	Impacting Storage Points*	Storage Time (Hours)	Component Data After Accounting for Storage MTBF (Hours)	Component Data After Accounting for Storage MDT (Hours)
20-P-1	Slurry Charge Pump	8,760	10	None			

*Storage points downstream of a component can affect the reliability and maintainability of a component as it is perceived by the downstream equipment. These points are identified on the Availability Block Diagram.

Gasification High-Temperature Gas Cooling

This subsystem of the plant represents state-of-the-art technology. Because operating experience with equipment in the gasification section of the plant is so limited, there is some uncertainty about the actual reliability and maintainability characteristics to be expected. One sensitivity study, which was conducted as a part of this work, quantifies the uncertainty in this section of the plant. Table 2-11 lists the components within the subsystem and their reliability and maintainability values. Figure 2-13 is the fault tree for this subsystem. More recent estimates for the mean time between failures of the component called "Process Burner with Jacket" suggest that the 1752-hour estimate reported in Table 2-11 may be conservative (i.e., low) by 25 percent or more.

The coal slurry from the storage tanks is pumped by the slurry charge pumps to the gasifier burners, where it combines with oxygen. The burner contains cooling coils through which tempered water is circulated. The gasifier 20-R-1 operates at a pressure of 600 psig and in a temperature range of 2400°F to 2600°F.

Table 2-11

GASIFICATION, HIGH-TEMPERATURE GAS COOLING, AND SCRUBBING COMPONENT DATA

Component Number	Component Name	Inherent Component Data MTBF (Hours)	Inherent Component Data MDT (Hours)	Impacting Storage Points*	Storage Time (Hours)	Component Data After Accounting for Storage MTBF (Hours)	Component Data After Accounting for Storage MDT (Hours)
20-R-1	Gasifier	2,190	12.8	None			
20-ME-1	Process Burner with Jacket	1,752	12.0	None			
20-E-10	Fuel Gas Reheater	33,288	37.7	None			
20-P-11A	BFW Circulation Pump	33,376	18.9	None			
20-P-11B	BFW Circulation Pump	33,376	18.9	None			
20-VS-1	Coarse Slag Dewatering Screen	17,520	10.0	None			
20-CV-1	Coarse Slag Transfer Conveyor	17,520	23.1	None			
20-P-10A	Scrubber Circulation Pump	33,376	17.5	None			
20-P-10B	Scrubber Circulation Pump	33,376	17.5	None			
N/A	Syngas Coolers**	8,760	193	None			
N/A	Scrubber†	8,760	26	None			
N/A	Slag Handling††	8,760	26	None			

*Storage points downstream of a component can affect the reliability and maintainability of a component as it is perceived by the downstream equipment. These points are identified on the Availability Block Diagram.

**Includes Radiant Boiler (20-E-8), Convective Boiler (20-E-9), H.P. Steam Drum (20-V-5).

†Includes Particulate Scrubber (20-V-6), Venturi Nozzle (20-ME-6).

††Includes Slag Lockhopper (20-V-2), Lockhopper Head Tank (20-TK-2), Slag Receiving Vessel with Rake (20-TK-3).

Hot crude gas with molten ash enters the radiant syngas cooler 20-E-8, where high-pressure (1545 psia) saturated steam is generated. The gas leaving the radiant syngas cooler at 1500°F is cooled to 650°F in the vertical convective syngas cooler (20-E-9), where additional high-pressure saturated steam is generated in the boiler tubes. Raw gas leaving the convective cooler is cooled in component 20-E-10 by heat exchange with reheated saturated fuel gas. This cooled gas is then scrubbed of particulates in component 20-V-6.

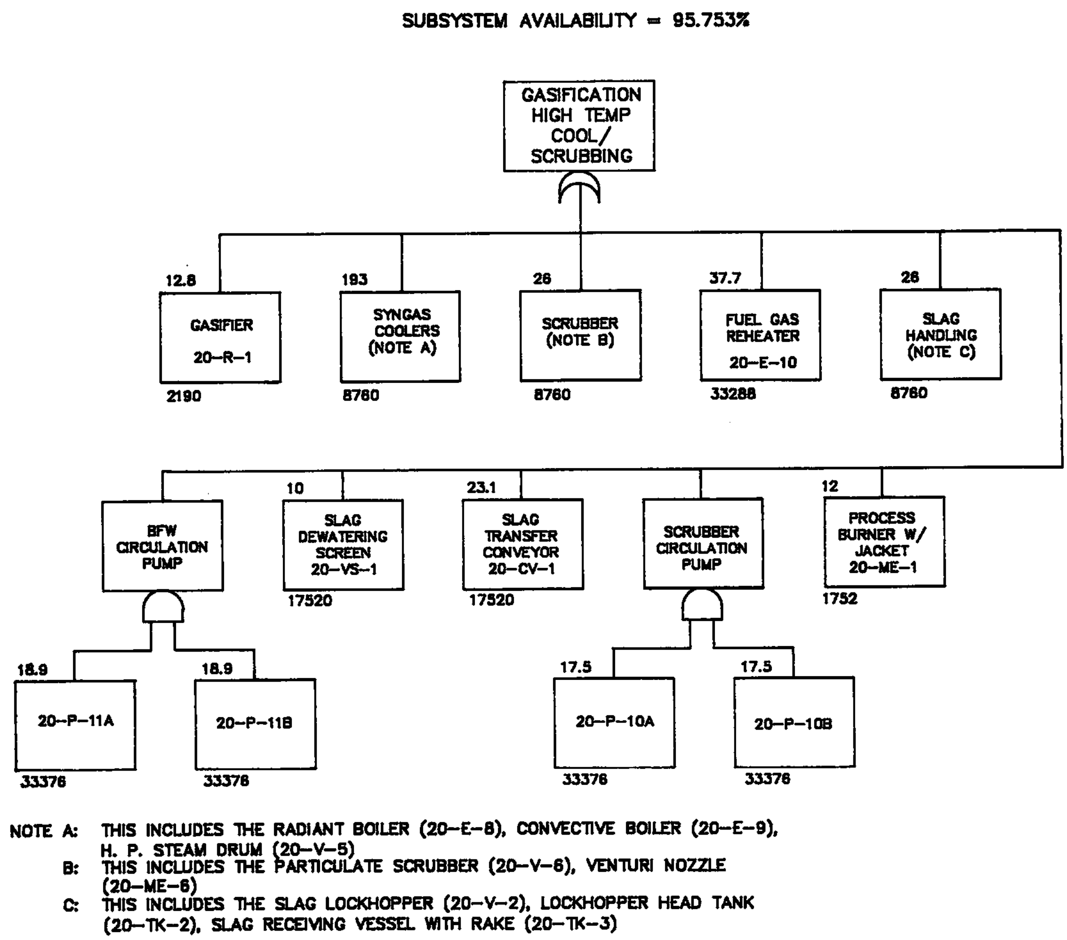


Figure 2-13. Gasification, High-Temperature Cooling and Scrubbing Fault Tree

Ash Dewatering

The components modeled in the ash dewatering fault tree are shown in Table 2-12. Figure 2-14 is the fault tree representation of the subsystem.

Table 2-12

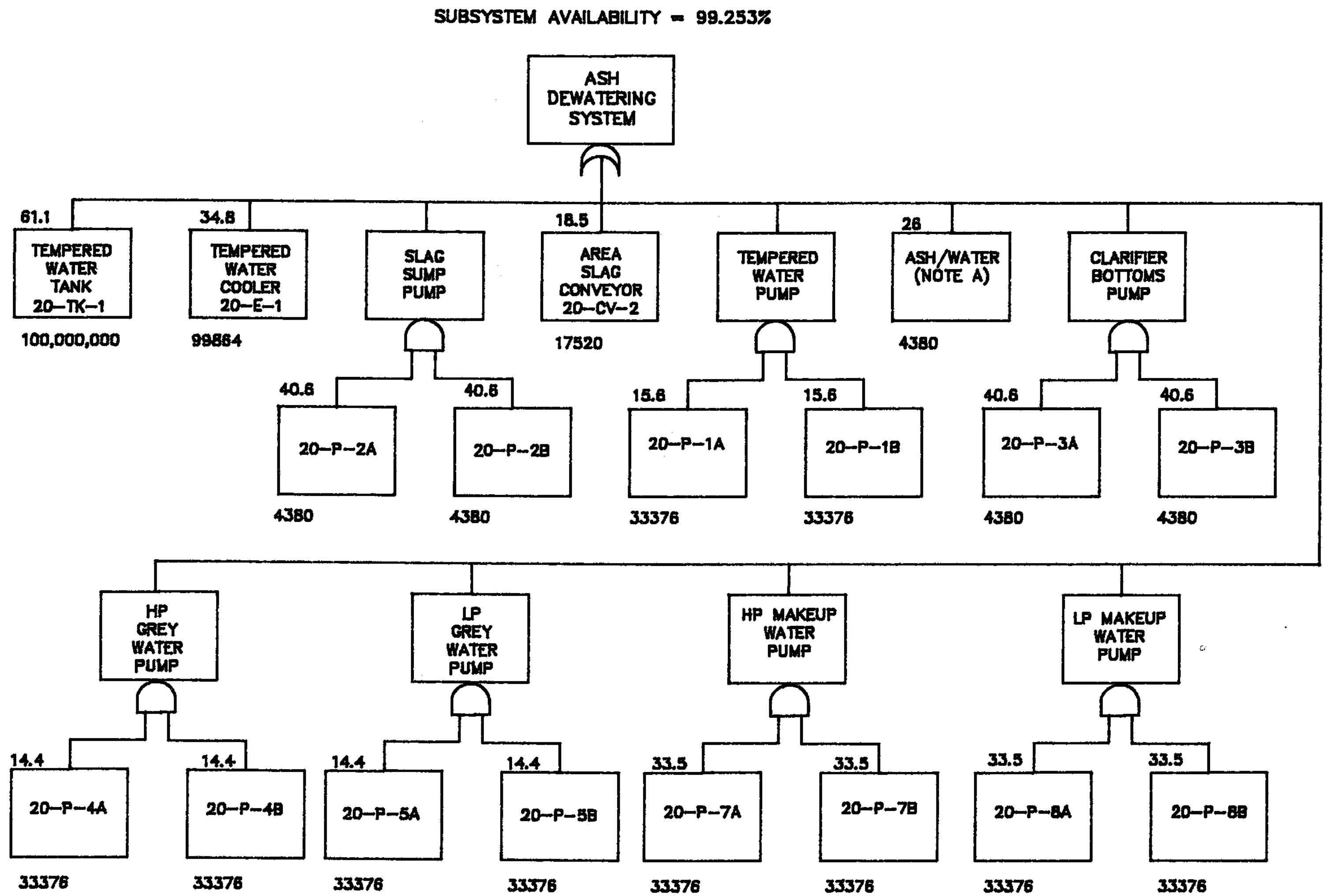
ASH DEWATERING SYSTEM COMPONENT DATA

Component Number	Component Name	Inherent Component Data MTBF (Hours)	Inherent Component Data MDT (Hours)	Impacting Storage Points*	Storage Time (Hours)	Component Data After Accounting for Storage MTBF (Hours)	Component Data After Accounting for Storage MDT (Hours)
20-TK-1	Tempered Water Tank	100,000,000	61.1	None			
20-E-1	Tempered Water Cooler	99,864	34.8	None			
20-CV-2	Area Slag Conveyor with Unloader	17,520	18.5	None			
20-P-1A	Tempered Water Pump	33,376	15.6	None			
20-P-1B	Tempered Water Pump	33,376	15.6	None			
20-P-2A	Slag Sump Pump	4,380	40.6	None			
20-P-2B	Slag Sump Pump	4,380	40.6	None			
20-P-3A	Clarifier Bottoms Pump	4,380	40.6	None			
20-P-3B	Clarifier Bottoms Pump	4,380	40.6	None			
20-P-4A	HP Grey Water Pump	33,376	14.4	None			
20-P-4B	HP Grey Water Pump	33,376	14.4	None			
20-P-5A	LP Grey Water Pump	33,376	14.4	None			
20-P-5B	LP Grey Water Pump	33,376	14.4	None			
20-P-7A	HP Makeup Water Pump	33,376	33.5	None			
20-P-7B	HP Makeup Water Pump	33,376	33.5	None			
20-P-8A	LP Makeup Water Pump	33,376	33.5	None			
20-P-8B	LP Makeup Water Pump	33,376	33.5	None			
N/A	Ash/Water**	4,380	26.0	None			

*Storage points downstream of a component can affect the reliability and maintainability of a component as it is perceived by the downstream equipment. These points are identified on the Availability Block Diagram.

**Includes the Carbon Water Flash Drum (20-V-3), Grey Water Tank (20-TK-6), Dearator (20-ME-1), Clarifier with Rake (20-SE-1), Fines Belt Filter (20-F-1), Fines Slag Conveyor (20-CV-3), Grey Water Cooler (20-E-2), Secondary Slag Sump with Mixer (20-TK-5).

The ash slurry from the quench pool at the bottom of the radiant cooler and the solids slurry produced in the gas scrubbing unit are fed to the ash dewatering subsystem. The water/slag mixture is cooled, clarified, and filtered to yield an ash cake and water.



NOTE A: THIS INCLUDES THE CARBON WATER FLASH DRUM (20-V-3), GREY WATER TANK (20-TK-6) DEARATOR (20-ME-1), CLARIFIER W/RAKE (20-SE-1), FINES BELT FILTER (20-F-1), FINES SLAG CONVEYOR (20-CV-3), GREY WATER COOLER (20-E-2), SECONDARY SLAG SUMP W/MIXER (20-TK-5)

Figure 2-14. Ash Dewatering System Fault Tree

Low-Temperature Gas Cooling and Fuel Gas Saturation

This system includes the following subsystems modeled in the availability block diagram of Figure 2-1.

- Saturator water heater II
- Water-cooled systems
- Air-cooled systems
- Rest of low-temperature gas cooling
- Fuel gas saturation

The fuel gas saturation and low-temperature gas cooling sections are being described together, because of the close heat integration of the two units. This high degree of integration, together with the multiple operational possibilities for these sections of the plant, necessitated the development of a rather complicated model in this region of the plant's availability block diagram. A process flow diagram for this area of the plant is shown for one of two equipment trains in Figure 2-15. A brief description of the process is given in the following two paragraphs.

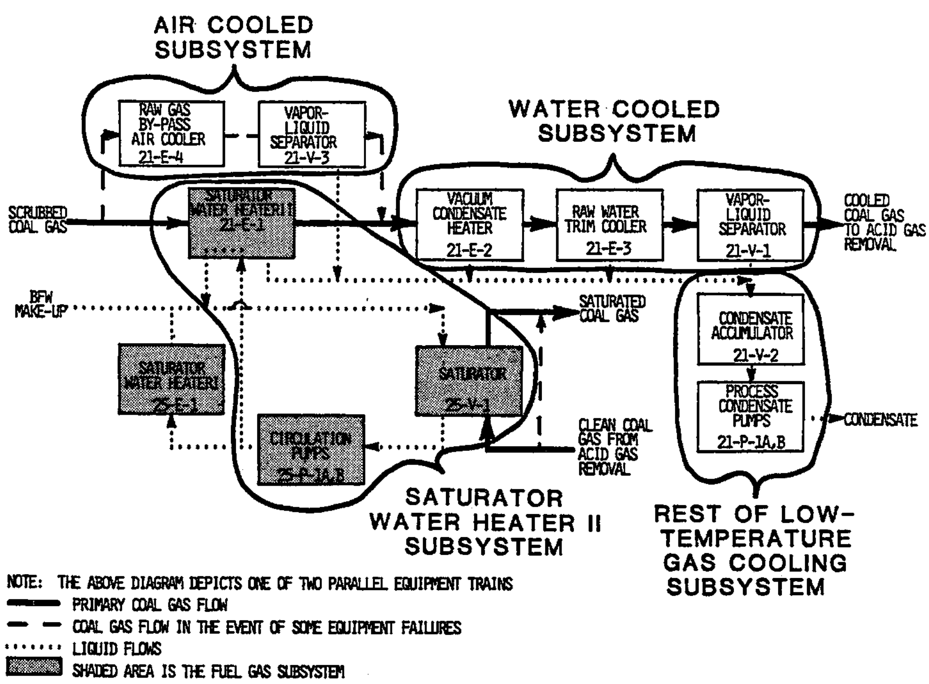


Figure 2-15. Low-Temperature Gas Cooling Process Flow Diagram

The solids-free raw gas from the particulate scrubbing unit is cooled in exchanger 21-E-1 by heat exchange with the circulating saturator water. Further cooling of the raw gas is accomplished in exchanger 21-E-2 by heat transfer against a combined flow of vacuum condensate and makeup water from the steam, BFW, and condensate systems. Condensate water flows to condensate collection drum 21-V-2. The raw gas is subsequently cooled in trim cooler 21-E-3. The cooled gas is separated from the condensate in knockout drum 21-V-1 and is sent to the acid gas removal subsystem.

The clean fuel gas from the acid gas removal subsystem is essentially free of moisture and enters the saturator (25-V-1). After being saturated with moisture, the fuel gas exits the saturator, is reheated in the gasification unit, and then fed to the combustion turbines. In the case of the Baseline with Supplemental Firing design, the supplemental fuel gas instead bypasses the saturator and is fired directly in the gas turbine exhaust duct. Only the fuel gas consumed in the gas turbines is saturated with moisture and reheated.

In Figure 2-15, envelopes have been drawn around four of the five subsystems under consideration here. The equipment in the fifth subsystem (the Fuel Gas Saturation subsystem) is shaded in grey. The failure of equipment within these subsystems can be described by the following table (Table 2-13), which has been extracted from the availability block diagram, Figure 2-1.

Table 2-13

SUMMARY OF LOW-TEMPERATURE GAS COOLING CAPACITY STATES

State	Saturator Water Heater II	Water-Cooled Systems	Air-Cooled Systems	Rest of Low-Temperature Gas Cooling	Train Capacity (Percent)
1	0	0	0	0	83.0
2	1	0	0	0	55.6
3	0	0	1	0	55.6
4	0	1	0	0	27.8
5	1	1	0	0	27.8
6	0	1	1	0	0.0
7	1	0	1	0	0.0
8	1	1	1	0	0.0
9	0 or 1	0 or 1	0 or 1	1	0.0

0 = Subsystem available.
1 = Subsystem NOT available.

All of the possible failure modes that can exist for the four subsystems are identified in the above table. In the first availability state listed, if no equipment has failed, each equipment train (of which there are two) has a capacity of 83 percent. In the second state listed, some equipment in the Saturator Water Heater II system has failed. (This failed equipment could be any one or more of the three components within this system.) Such a failure would, according to Table 2-13, lead to a reduction in train capacity to 55.6 percent. Likewise, states 3 through 9 in the table define other failure modes and their associated capacity consequences.

In Figure 2-16, the direction of process flows under the various failure modes enumerated in Table 2-13 are identified by the grey shaded region. Failures in any of the four subsystems enumerated in the preceding table will affect the coal throughput (and thus power output) capability of the plant. A secondary effect arises as a consequence of a failure of any equipment in the Fuel Gas Saturation subsystem, which is depicted by grey shading in Figure 2-15. Failure of this equipment (regardless of the status of the other modes) will always cause some partial plant derating because such failures preclude the efficient process step consisting of fuel gas saturation. The availability implications of this partial derating are captured in the availability block diagram shown in Figure 2-17.

While the model for this section of the IGCC plant is quite complicated, the overall plant unavailability attributable to the equipment is less than 0.5 percentage points expressed in terms of the equivalent forced outage rate.

Fault trees and tables for the low-temperature gas cooling and fuel gas saturation sections of the plant are presented as follows:

Subsystem	Fault Tree	Component Reliability and Maintainability Data Table
Saturator Water Heater II	Figure 2-18	Table 2-14
Water-Cooled Systems	Figure 2-19	Table 2-15
Air-Cooled Systems	Figure 2-20	Table 2-16
Rest of Low-Temperature Gas Cooling	Figure 2-21	Table 2-17
Fuel Gas Saturation	Figure 2-22	Table 2-18

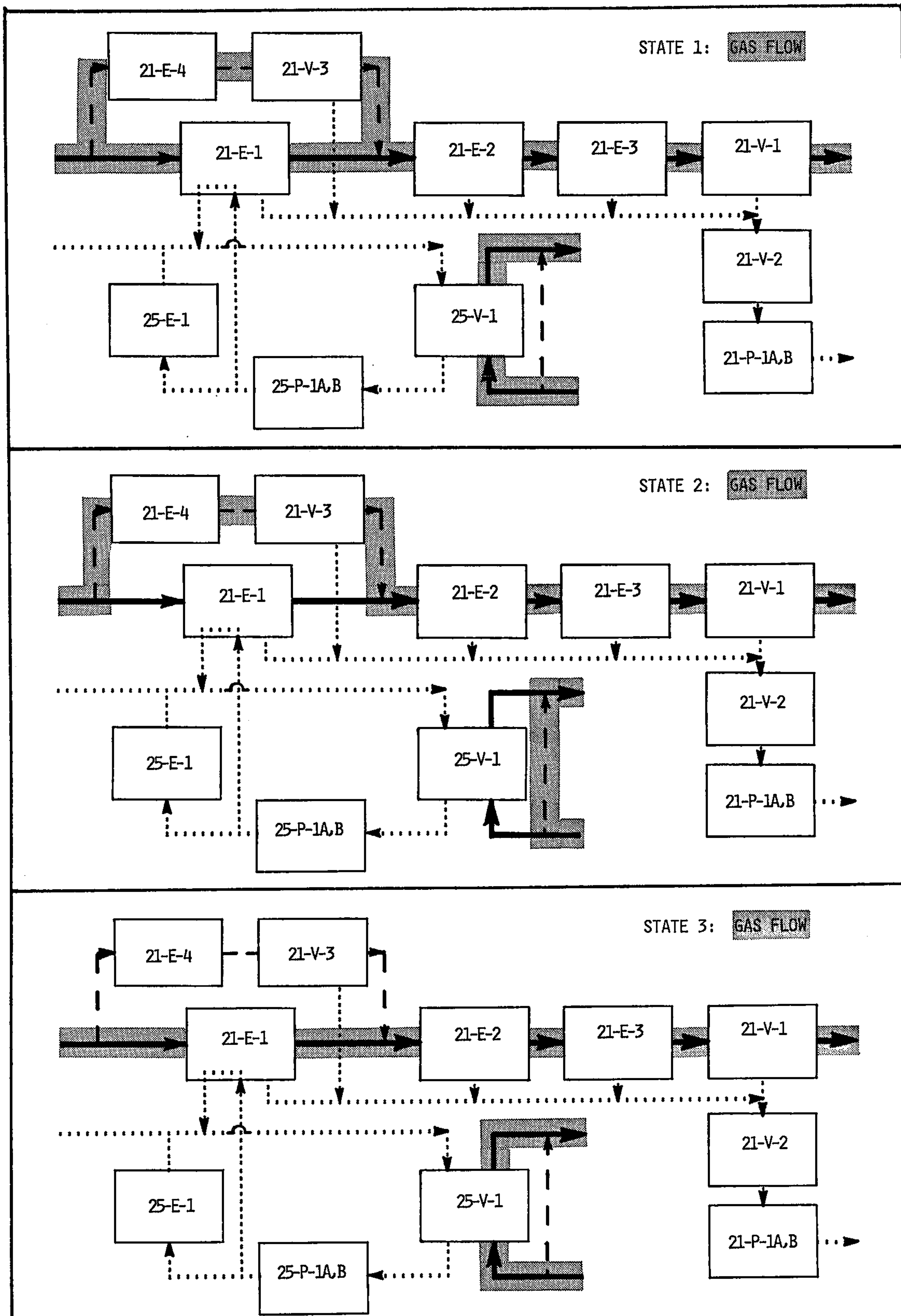


Figure 2-16. Process Flows in Various Plant States

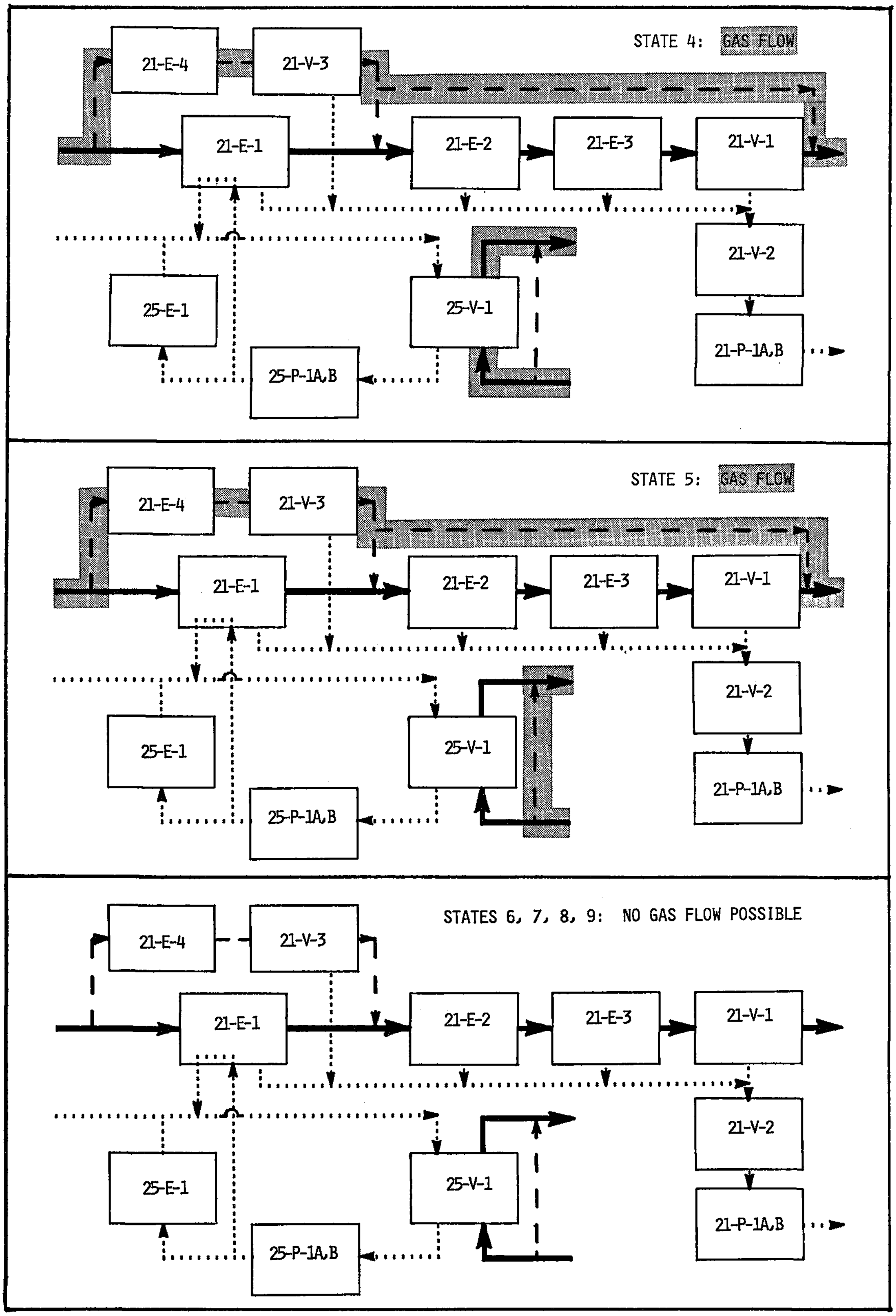
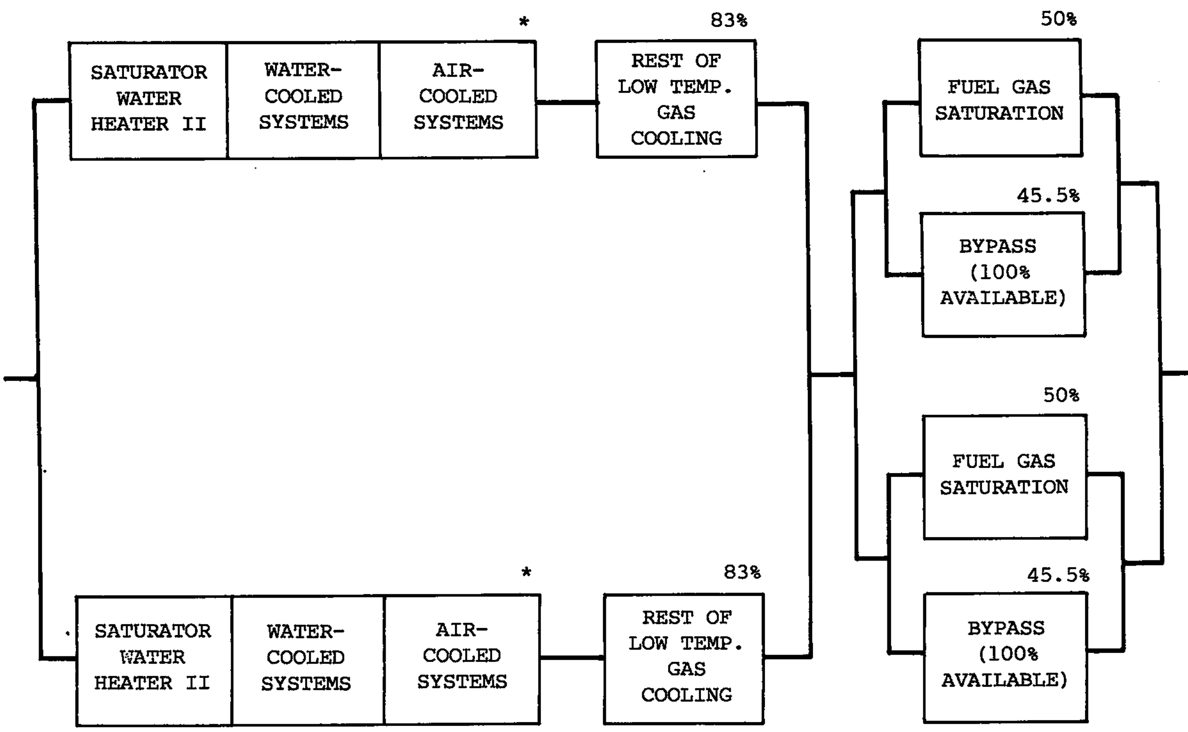


Figure 2-16 (continued). Process Flows in Various Plant States



*See Table 2-13.

Figure 2-17. Low-Temperature Gas Cooling and Fuel Gas Saturation Portion of the Availability Block Diagram

Table 2-14

SATURATOR WATER HEATER II COMPONENT DATA

Component Number	Component Name	Inherent Component Data MTBF (Hours)	MDT (Hours)	Impacting Storage Points*	Storage Time (Hours)	Component Data After Accounting for Storage MTBF (Hours)	MDT (Hours)
21-E-1	Saturator Water Heater II	33,288	34.3	None			
25-V-1	Saturator	17,520	28.0	None			
25-P-1A	Saturator Circulation Pump	33,376	16.1	None			
25-P-1B	Saturator Circulation Pump	33,376	16.1	None			

*Storage points downstream of a component can affect the reliability and maintainability of a component as it is perceived by the downstream equipment. These points are identified on the Availability Block Diagram.

SUBSYSTEM AVAILABILITY = 99.738%

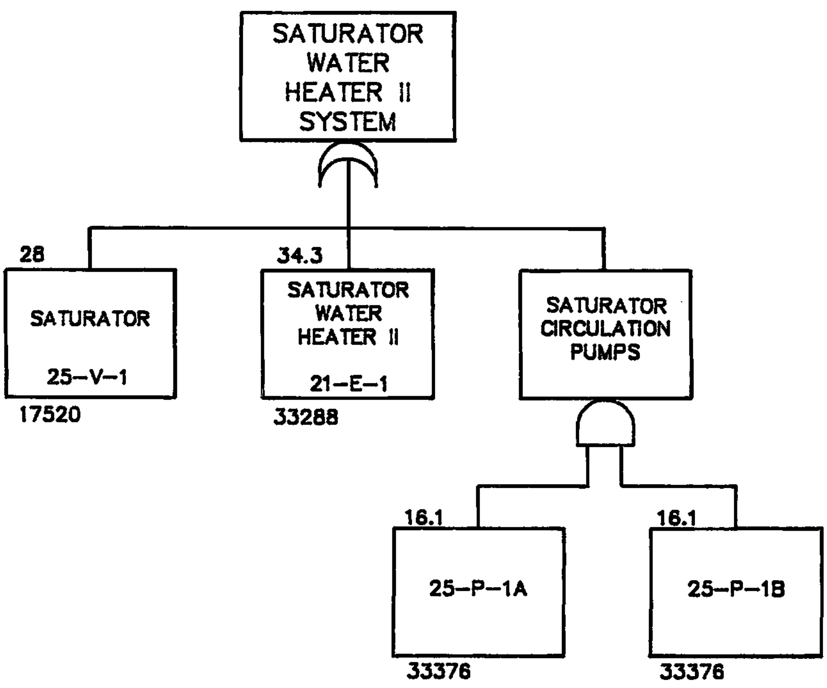


Figure 2-18. Saturator Water Heater II System Fault Tree

Table 2-15

WATER-COOLED SYSTEM COMPONENT DATA

Component Number	Component Name	Inherent Component Data MTBF (Hours)	Inherent Component Data MDT (Hours)	Impacting Storage Points*	Storage Time (Hours)	Component Data After Accounting for Storage MTBF (Hours)	Component Data After Accounting for Storage MDT (Hours)
21-E-3	Raw Water Trim Cooler	33,288	34.3	None			
21-E-2	Vacuum Condensate Heater	33,288	34.3	None			
21-V-1	Vapor-Liquid Separator	91,104	16.0	None			

*Storage points downstream of a component can affect the reliability and maintainability of a component as it is perceived by the downstream equipment. These points are identified on the Availability Block Diagram.

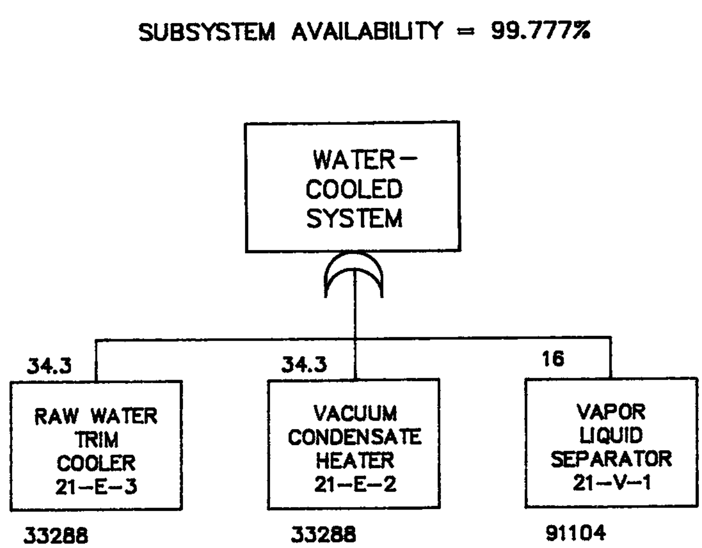


Figure 2-19. Water-Cooled System Fault Tree

Table 2-16

AIR-COOLED SYSTEM COMPONENT DATA

Component Number	Component Name	Inherent Component Data MTBF (Hours)	Inherent Component Data MDT (Hours)	Impacting Storage Points*	Storage Time (Hours)	Component Data After Accounting for Storage MTBF (Hours)	Component Data After Accounting for Storage MDT (Hours)
21-E-4	Raw Gas Bypass Air Cooler	15,768	5.1	None			
21-V-3	Vapor Liquid Separator	91,104	16.0	None			

*Storage points downstream of a component can affect the reliability and maintainability of a component as it is perceived by the downstream equipment. These points are identified on the Availability Block Diagram.

SUBSYSTEM AVAILABILITY = 99.950%

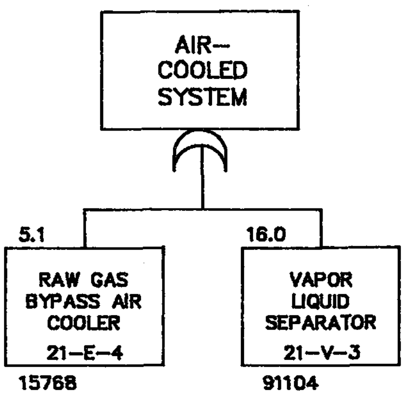


Figure 2-20. Air-Cooled System Fault Tree

Table 2-17

REST OF LOW-TEMPERATURE GAS COOLING COMPONENT DATA

Component Number	Component Name	Inherent Component Data MTBF (Hours)	Inherent Component Data MDT (Hours)	Impacting Storage Points*	Storage Time (Hours)	Component Data After Accounting for Storage MTBF (Hours)	Component Data After Accounting for Storage MDT (Hours)
21-V-2	Condensate Accumulator	91,104	16.0	None			
21-P-1A	Process Condensate Pump	33,288	14.0	None			
21-P-1B	Process Condensate Pump	33,288	14.0	None			

*Storage points downstream of a component can affect the reliability and maintainability of a component as it is perceived by the downstream equipment. These points are identified on the Availability Block Diagram.

SUBSYSTEM AVAILABILITY = 99.982%

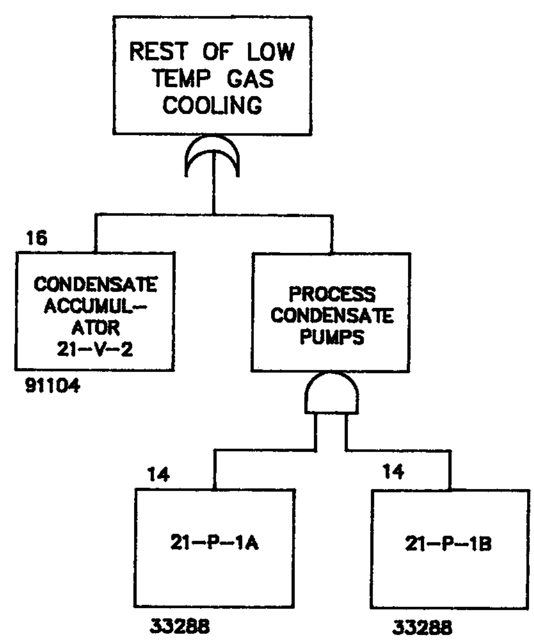


Figure 2-21. Rest of Low-Temperature Gas Cooling Fault Tree

Table 2-18

FUEL GAS SATURATION COMPONENT DATA

Component Number	Component Name	Inherent Component Data MTBF (Hours)	Inherent Component Data MDT (Hours)	Impacting Storage Points*	Storage Time (Hours)	Component Data After Accounting for Storage MTBF (Hours)	Component Data After Accounting for Storage MDT (Hours)
21-E-1	Saturator Water Heater II	33,288	34.3	None			
25-E-1	Saturator Water Heater I	99,864	33.3	None			
25-V-1	Saturator	17,520	28.0	None			
25-P-1A	Circulation Pump	33,376	16.1	None			
25-P-1B	Circulation Pump	33,376	16.1	None			

*Storage points downstream of a component can affect the reliability and maintainability of a component as it is perceived by the downstream equipment. These points are identified on the Availability Block Diagram.

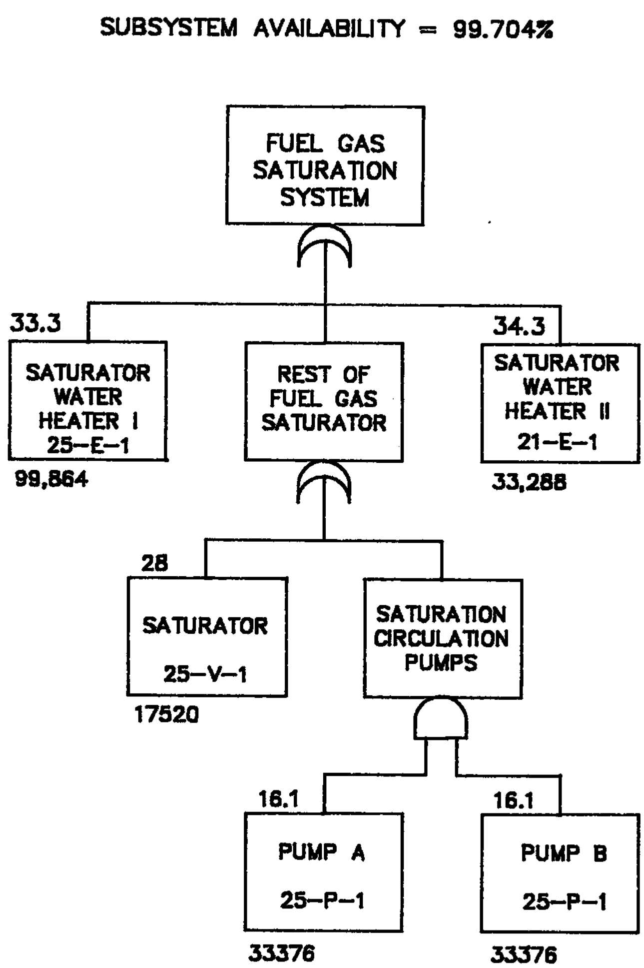


Figure 2-22. Fuel Gas Saturation System Fault Tree

Acid Gas Removal

The fault tree for the acid gas removal subsystem is shown in Figure 2-23. Table 2-19 lists the components and their respective reliability and maintainability values. All components in the subsystem have been modeled under a common OR gate with the exception of the 100-percent-capacity regenerator reflux pumps and lean-solution pumps, which are modeled under AND gates.

The acid gas removal subsystem employs the Selexol™ process for selective removal of hydrogen sulfide (H_2S). In the acid gas removal unit, 95.4 percent of the entering sulfur is removed by absorption in the Selexol solvent. Sulfur compounds stripped from the Selexol solvent, together with sulfur compounds from process water treating and from tail gas treating, are converted to elemental sulfur downstream in the sulfur plant, producing an overall sulfur recovery of 95.2 percent.

Sulfur Recovery

The sulfur plant, as modeled in the availability block diagram, consists of two parallel 111-percent capacity subsystems. The components modeled are shown in Table 2-20. The fault tree for the subsystem is shown in Figure 2-24. All components have been modeled under a common OR gate with the exception of the 111-percent sulfur transfer pumps, which are modeled under an AND gate. Actual sulfur recovery per pass in the sulfur plant is approximately 91.6 percent of the total sulfur entering the sulfur plant. Unrecovered sulfur is sent to the tail gas treating plant, where the sulfur is recovered as H_2S and is recycled back to the sulfur plant. As a result of this recycle, the sulfur plant yields 95.2-percent overall sulfur recovery.

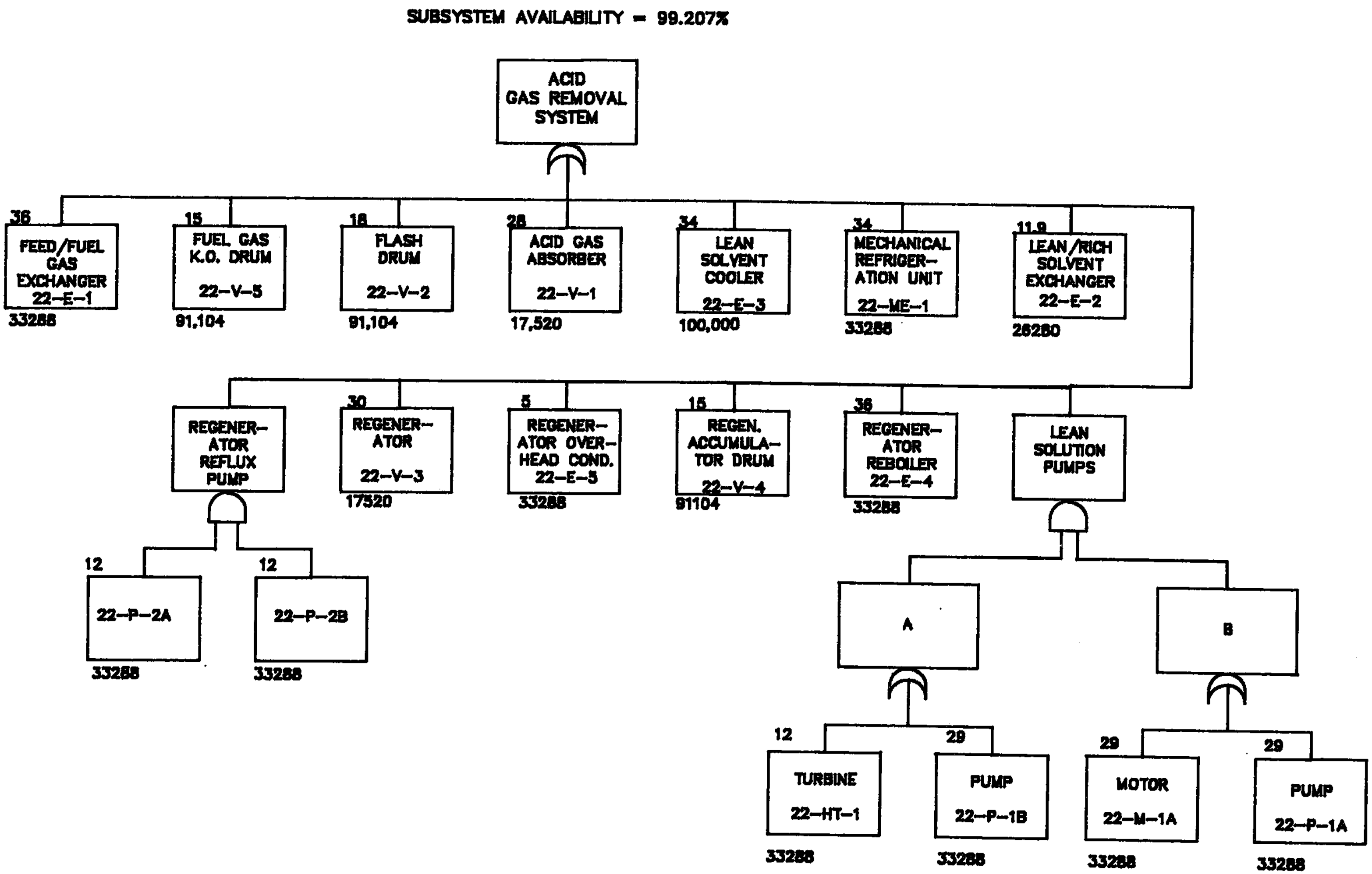


Figure 2-23. Acid Gas Removal System Fault Tree

Table 2-19

ACID GAS REMOVAL COMPONENT DATA

		Inherent Component Data				Component Data After Accounting for Storage	
Component Number	Component Name	MTBF (Hours)	MDT (Hours)	Impacting Storage Points*	Storage Time (Hours)	MTBF (Hours)	MDT (Hours)
22-E-1	Feed/Fuel Gas Exchanger	33,288	36.0	None			
22-V-5	Fuel Gas K.O. Drum	91,104	15.0	None			
22-V-2	Flash Drum	91,104	18.0	None			
22-V-1	Acid Gas Absorber	17,520	28.0	None			
22-E-3	Lean Solvent Cooler	100,000	34.0	None			
22-ME-1	Mechanical Refrigeration Unit	33,288	34.0	None			
22-E-2	Lean/Rich Solvent Exchanger	26,280	11.9	None			
22-P-2A	Regenerator Reflux Pump	33,288	12.0	None			
22-P-2B	Regenerator Reflux Pump	33,288	12.0	None			
22-V-3	Regenerator	17,520	30.0	None			
22-E-5	Regenerator Overhead Condenser	33,288	5.0	None			
22-V-4	Regenerator Accumulator Drum	91,104	15.0	None			
22-E-4	Regenerator Reboiler	33,288	36.0	None			
22-HT-1	Hydraulic Turbine	33,288	12.0	None			
22-P-1A	Lean Solution Pump	33,288	29.0	None			
22-P-1B	Lean Solution Pump	33,288	29.0	None			
22-M-1A	Motor	33,288	29.0	None			

*Storage points downstream of a component can affect the reliability and maintainability of a component as it is perceived by the downstream equipment. These points are identified on the Availability Block Diagram.

Table 2-20

SULFUR RECOVERY COMPONENT DATA

Component Number	Component Name	Inherent Component Data MTBF (Hours)	Inherent Component Data MDT (Hours)	Impacting Storage Points*	Storage Time (Hours)	Component Data After Accounting for Storage MTBF (Hours)	Component Data After Accounting for Storage MDT (Hours)
23-S-1	Sulfur Sump	1,000,000	10.0	None			
23-E-2	Sulfur Condenser I	33,288	47.0	None			
23-R-1	Sulfur Converter I	26,280	70.0	None			
23-H,E-1	Sulfur Furnace Waste Heat Boiler	17,520	78.0	None			
23-P-1A	Sulfur Transfer Pump	8,760	26.0	None			
23-P-1B	Sulfur Transfer Pump	8,760	26.0	None			
23-BL-1	Air Blower	8,760	28.0	None			
23-R-2	Sulfur Converter II	26,280	59.0	None			
23-E-3	Sulfur Condenser II	33,288	47.0	None			
23-V-1	Tail Gas Coalescer	91,104	16.0	None			

*Storage points downstream of a component can affect the reliability and maintainability of a component as it is perceived by the downstream equipment. These points are identified on the Availability Block Diagram.

SUBSYSTEM AVAILABILITY = 98.457%

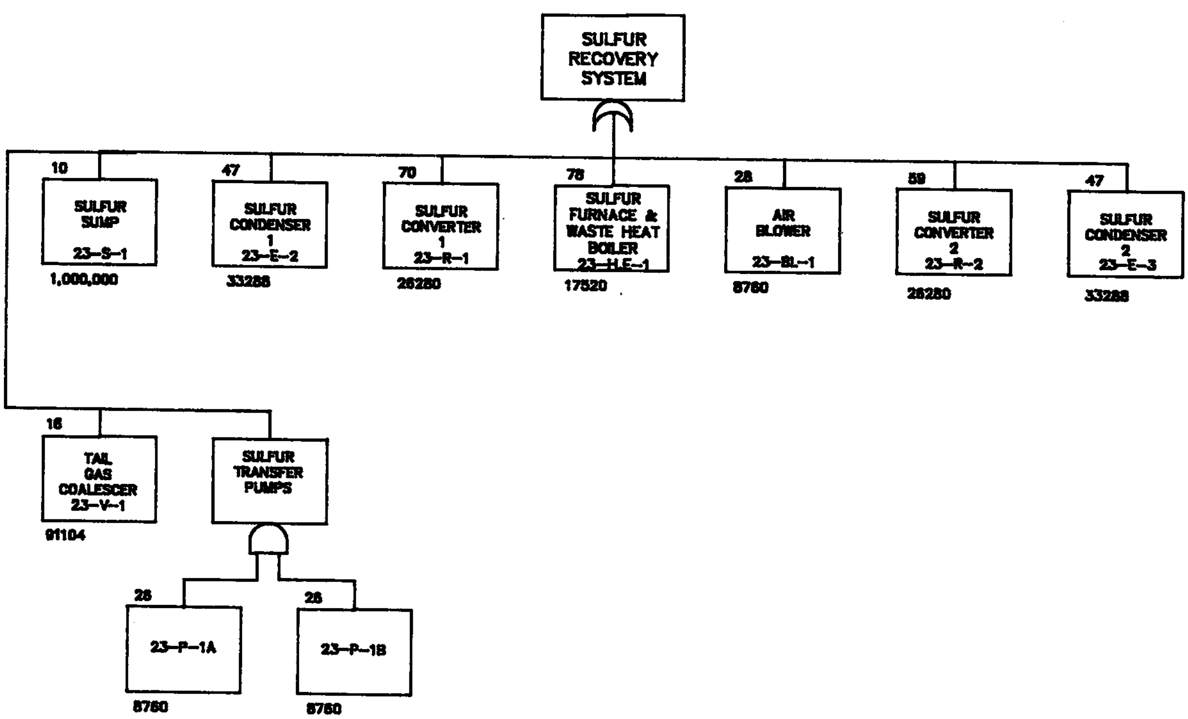


Figure 2-24. Sulfur Recovery System Fault Tree

Wastewater Treating

The details of the wastewater treating system are proprietary to Texaco, Inc. and cannot be reproduced in this report. The system was specified to have an availability of 0.9990. The mean downtime and mean time between failures calculations for this subsystem were based on this availability value and on the assumption of one failure every year.

Table 2-21 lists the components modeled in the wastewater treating subsystem. Figure 2-25 is the fault tree representation of the subsystem.

Flare Subsystem

The flare subsystem as modeled in the availability block diagram (ABD) is a perfectly available subsystem. It is included in the ABD to show that, if the tail gas treating system is unavailable, the "flow" of availability will not be interrupted, because of the ability to flare tail gas. One sensitivity study in Section 3 of this report evaluates the availability impact of not being able to flare tail gas. Table 2-22 presents the component reliability and maintainability data for the subsystem. Figure 2-26 is the fault tree representation of the subsystem.

Tail Gas Treating

The tail gas treating subsystem is modeled in parallel with the flare subsystem. Table 2-23 lists the components modeled in the tail gas treating subsystem. Figure 2-27 is the fault tree representation of the subsystem.

Table 2-21

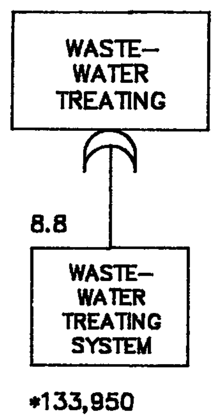
WASTEWATER TREATING COMPONENT DATA

Component Number	Component Name	Inherent Component Data MTBF (Hours)	Inherent Component Data MDT (Hours)	Impacting Storage Points*	Storage Time (Hours)	Component Data After Accounting for Storage MTBF (Hours)	Component Data After Accounting for Storage MDT (Hours)
N/A	Wastewater Treating	8,760	8.8	5	24	133,950	8.8

*Storage points downstream of a component can affect the reliability and maintainability of a component as it is perceived by the downstream equipment. These points are identified on the Availability Block Diagram.

SUBSYSTEM AVAILABILITY

IN THE ABSENCE OF STORAGE = 99.900%
AFTER ACCOUNTING FOR STORAGE = 99.993%



*AFFECTED BY STORAGE. RELIABILITY AND MAINTAINABILITY DATA FOR THIS EQUIPMENT BOTH WITH AND WITHOUT CONSIDERATION OF DOWNSTREAM STORAGE CAN BE FOUND ON TABLE 2-20.

Figure 2-25. Wastewater Treating Fault Tree

Table 2-22

FLARE COMPONENT DATA

		Inherent Component Data				Component Data After Accounting for Storage	
Component Number	Component Name	MTBF (Hours)	MDT (Hours)	Impacting Storage Points*	Storage Time (Hours)	MTBF (Hours)	MDT (Hours)
N/A	Flaring	100,000,000	1.0	None			

*Storage points downstream of a component can affect the reliability and maintainability of a component as it is perceived by the downstream equipment. These points are identified on the Availability Block Diagram.

SUBSYSTEM AVAILABILITY = 100.00%

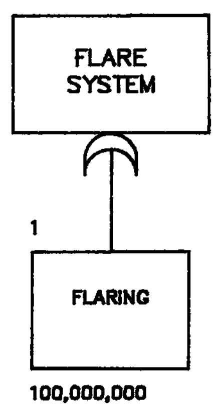


Figure 2-26. Flare System Fault Tree

Table 2-23

TAIL GAS TREATING COMPONENT DATA

Component Number	Component Name	Inherent Component Data MTBF (Hours)	MDT (Hours)	Impacting Storage Points*	Storage Time (Hours)	Component Data After Accounting for Storage MTBF (Hours)	MDT (Hours)
24-V-1	Hydrogenation Reactor	26,280	60.7	None			
24-H-1	Reducing Gas Generator	17,520	36.1	None			
24-E-6	Waste Heat Boiler	33,288	32.2	None			
24-V-2	Water Wash Cooling Tower	17,520	28.0	None			
24-E-1	Air Cooler	99,864	34.0	None			
24-V-3	Absorber	17,520	28.0	None			
24-E-2	Lean/Rich Solvent Exchanger	33,288	36.0	None			
24-E-3	Lean Solvent Cooler	99,864	34.0	None			
24-P-1A	Water Wash Cooling Tower Pump	33,376	15.7	None			
24-P-1B	Water Wash Cooling Tower Pump	33,376	15.7	None			
24-V-4	Regenerator	17,520	30.0	None			
24-P-2A	Rich Solvent Pump	33,376	29.0	None			
24-P-2B	Rich Solvent Pump	33,376	29.0	None			
24-E-4	Regenerator Reboiler	33,288	36.0	None			
24-E-5	Regenerator Overhead Condenser	15,768	5.0	None			
24-P-3A	Lean Solvent Pump	33,376	29.0	None			
24-P-3B	Lean Solvent Pump	33,376	29.0	None			
24-V-5	Acid Gas K.O. Drum	91,104	15.0	None			
24-P-4A	Regenerator Reflux Pump	33,376	12.0	None			
24-P-4B	Regenerator Reflux Pump	33,376	12.0	None			

*Storage points downstream of a component can affect the reliability and maintainability of a component as it is perceived by the downstream equipment. These points are identified on the Availability Block Diagram.

Tail gas from coalescer 23-V-1 in the sulfur recovery unit contains H_2S, SO_2, and COS, and elemental sulfur species S_6 and S_8. The gas must be processed further to remove these sulfur compounds.

The tail gas treating system uses a SCOT™ process to treat tail gas. The SCOT process is designed to remove H_2S from effluent gas streams. The SCOT solvent is not suitable for handling gas streams that contain substantial amounts of SO_2, COS, S_6, and S_8. Therefore, these compounds must be catalytically reduced (or hydrolyzed in the case of COS) to H_2S.

The catalytic reactions require hydrogen. Feedgas with a hydrogen content of 1.5 percent in excess of the stoichiometric demand is sufficient to convert almost all sulfur compounds to H_2S with the exception of a small residual of COS. The tail gas stream itself does not contain enough hydrogen or enough carbon monoxide to

SUBSYSTEM AVAILABILITY = 98.653%

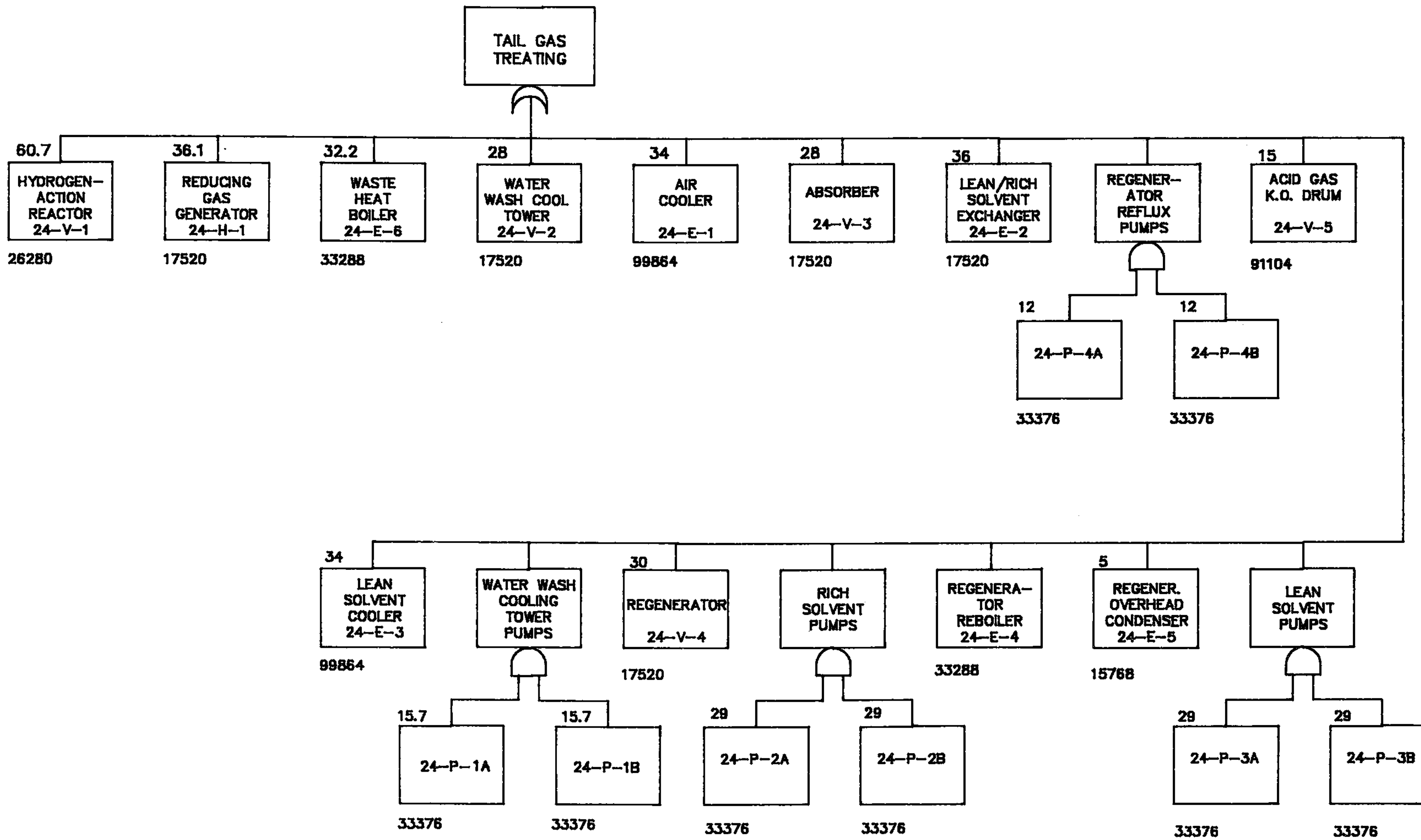


Figure 2-27. Tail Gas Treating Fault Tree

react with the various sulfur compounds. The flash gas from the acid gas removal unit supplies the necessary hydrogen and carbon monoxide.

Boiler Feedwater Subsystem

Table 2-24 lists the components modeled in the boiler feedwater subsystem fault tree. The fault tree is shown in Figure 2-28. The boiler feedwater subsystem encompasses the sections of the steam, boiler feedwater, and condensate subsystems from raw water through condensate polishing unit 30-ME-2, including blowdown flashdrum 30-V-1.

Raw water is first treated in demineralizer 30-ME-1. Treated water, suitable for steam generation, is stored in demineralized water storage tank 30-TK-2, which has a 24-hour capacity. Demineralized water is pumped to condensate surge tank 30-TK-3 (30-minute holdup), where it combines with the vacuum condensate from surface condenser 51-E-17 and low-pressure steam condensate from process units. Condensate is then pumped by condensate transfer pumps 30-P-4A and B to condensate polishing unit 30-ME-2.

Also included in the boiler feedwater subsystem is blowdown flash drum 30-V-1. Blowdown streams from the various steam drums in the plant are combined and flashed in 30-V-1. The 35-psia steam recovered from the flash drum is used in the deaerator.

Table 2-24

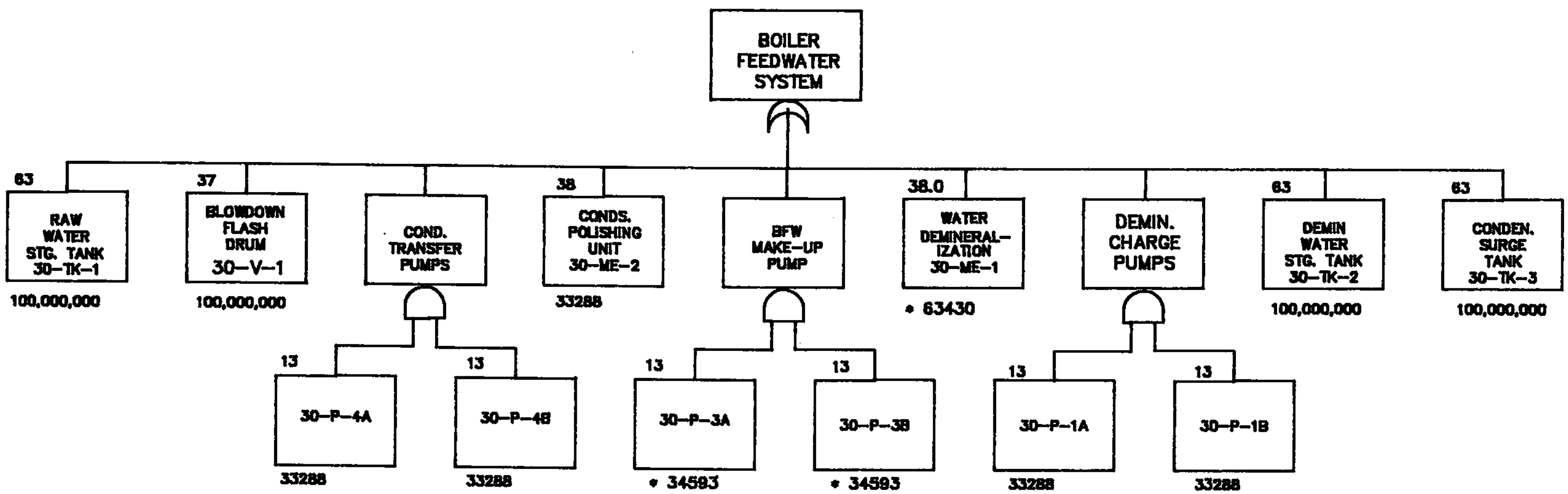
BOILER FEEDWATER COMPONENT DATA

Component Number	Component Name	Inherent Component Data MTBF (Hours)	Inherent Component Data MDT (Hours)	Impacting Storage Points*	Storage Time (Hours)	Component Data After Accounting for Storage MTBF (Hours)	Component Data After Accounting for Storage MDT (Hours)
30-P-3A	BFW Makeup Pump	33,288	13.0	9	0.5	34,593	13.0
30-P-3B	BFW Makeup Pump	33,288	13.0	9	0.5	34,593	13.0
30-ME-1	Water Demineralizer	33,288	38.0	8,9	24.5	63,430	38.0
30-TK-1	Raw Water Storage Tank	100,000,000	63.0	None			
30-V-1	Blowdown Flash Drum	100,000,000	37.0	None			
30-P-4A	Condensate Transfer Pump	33,288	13.0	None			
30-P-4B	Condensate Transfer Pump	33,288	13.0	None			
30-ME-2	Condensate Polishing Unit	33,288	38.0	None			
30-TK-2	Demineralized Water Storage Tank	100,000,000	63.0	None			
30-TK-3	Condensate Surge Tank	100,000,000	63.0	None			
30-P-1A	Demineralizer Charge Pump	33,288	13.0	None			
30-P-1B	Demineralizer Charge Pump	33,288	13.0	None			

*Storage points downstream of a component can affect the reliability and maintainability of a component as it is perceived by the downstream equipment. These points are identified on the Availability Block Diagram.

SUBSYSTEM AVAILABILITY

IN THE ABSENCE OF STORAGE = 99.772%
AFTER ACCOUNTING FOR STORAGE = 99.826%



*AFFECTED BY STORAGE. RELIABILITY AND MAINTAINABILITY DATA FOR THIS EQUIPMENT BOTH WITH AND WITHOUT CONSIDERATION OF DOWNSTREAM STORAGE CAN BE FOUND ON TABLE 2-24.

Figure 2-28. Boiler Feedwater System Fault Tree

Combustion Turbine/Generator

The combustion turbine/generator subsystem includes the combustion turbine (consisting of an air compressor, a combustor, and an expansion turbine) and a generator. Figure 2-29 is the fault tree for this subsystem. Table 2-25 lists the components modeled and their respective reliability and maintainability values.

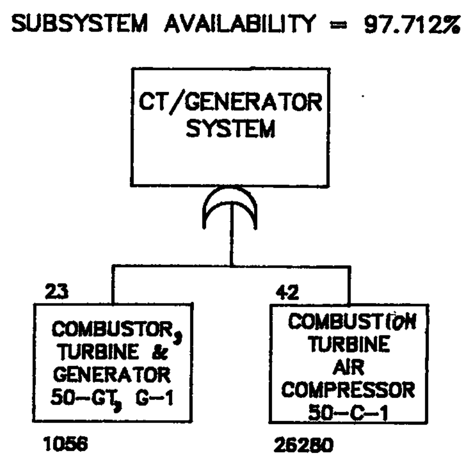


Figure 2-29. Combustion Turbine/Generator System Fault Tree

Table 2-25

COMBUSTION TURBINE AND GENERATOR COMPONENT DATA

Component Number	Component Name	Inherent Component Data MTBF (Hours)	Inherent Component Data MDT (Hours)	Impacting Storage Points*	Storage Time (Hours)	Component Data After Accounting for Storage MTBF (Hours)	Component Data After Accounting for Storage MDT (Hours)
50-GT-1,G-1	Combustor, Expansion Turbine, and Generator	1,056	23.0	None			
50-C-1	Air Compressor	26,280	42.0	None			

*Storage points downstream of a component can affect the reliability and maintainability of a component as it is perceived by the downstream equipment. These points are identified on the Availability Block Diagram.

Reheated fuel gas at 570°F with 28.2-percent (by weight) moisture is introduced to the gas turbine combustor, together with air supplied by the compressor. The compressor is driven by the gas turbine expander. The combustion turbine employed in this design has a firing temperature of 2200°F.

<u>Heat Recovery Steam Generator</u>

The heat recovery steam generator (HRSG) utilizes heat exhausted by the combustion turbines to produce steam, which then feeds to the steam turbine to produce power. The components modeled in the HRSG system are shown in Table 2-26. Figure 2-30 is the fault tree representation of the subsystem.

Gas turbine exhaust, together with the supplemental-fuel-gas combustion products in the case of the Baseline with Supplemental Firing design, is ducted to the HRSG. The HRSG provides superheating of high-pressure steam and reheating of intermediate-pressure steam, supplements high-pressure and 100-psia steam generation, and preheats boiler feedwater.

Each HRSG is provided with its own steam drums. Boiler feedwater (BFW) circulation between evaporator coils and steam drums is accomplished by density difference.

<u>Steam Turbine Generator Subsystem</u>

The components modeled in this subsystem are shown in Table 2-27. Figure 2-31 is the fault tree representation of the subsystem. All components have been modeled under a common OR gate with the exception of all pumps, which have been modeled under AND gates.

The steam turbine comprises high-pressure (HP), intermediate-pressure (IP), and medium-pressure (MP) power turbines and a generator. The high-pressure power turbine receives 1465-psia superheated steam at a temperature between 970°F and 1000°F. Reheated IP steam at 310 psia and 970°F to 1000°F is supplied to the IP power turbine. The MP power turbine receives the IP power turbine exhaust and condenses it. A fraction of the steam flow from the MP power turbine is extracted and desuperheated to meet process demands for 55-psia steam.

The HP BFW pump is steam-turbine-driven (with a motor-driven spare) and discharges at 1785 psia. This steam turbine receives a portion of the 115 psia IP power turbine exhaust. The MP BFW pump is motor-driven and discharges at 145 psia. Both of the BFW pumps take suction from the deaerator.

Table 2-26

HEAT RECOVERY STEAM GENERATOR COMPONENT DATA

Component Number	Component Name	Inherent Component Data MTBF (Hours)	Inherent Component Data MDT (Hours)	Impacting Storage Points*	Storage Time (Hours)	Component Data After Accounting for Storage MTBF (Hours)	Component Data After Accounting for Storage MDT (Hours)
51-V-2	M.P. Steam Drum	66,667	39.0	None			
51-V-1	H.P. Steam Drum	66,667	39.0	None			
51-B-1	Heat Recovery Steam Generator	1,499	20.0	None			

*Storage points downstream of a component can affect the reliability and maintainability of a component as it is perceived by the downstream equipment. These points are identified on the Availability Block Diagram.

SUBSYSTEM AVAILABILITY = 98.568%

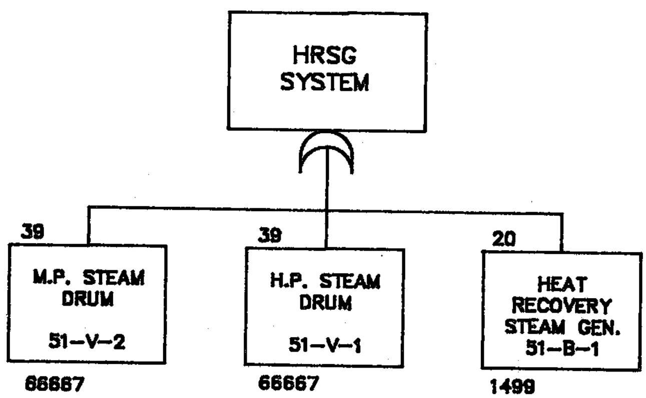


Figure 2-30. Heat Recovery Steam Generator Fault Tree

Table 2-27

STEAM TURBINE AND GENERATOR COMPONENT DATA

Component Number	Component Name	Inherent Component Data MTBF (Hours)	Inherent Component Data MDT (Hours)	Impacting Storage Points*	Storage Time (Hours)	Component Data After Accounting for Storage MTBF (Hours)	Component Data After Accounting for Storage MDT (Hours)
51-P-1A	H.P. BFW Pump	33,288	134	None			
51-P-1B	H.P. BFW Pump	33,288	134	None			
51-T-3A	H.P. BFW Pump Motor	17,000	64	None			
51-T-3B	H.P. BFW Pump Turbine Driver	17,000	64	None			
51-E-8	Condensate Heater	100,000	34	None			
51-P-3A	Vacuum Condensate Pump	33,288	31	None			
51-P-3B	Vacuum Condensate Pump	33,288	31	None			
51-DA-1	Deaerator	71,429	38	None			
51-P-4A	BFW Return Booster Pump	33,288	134	None			
51-P-4B	BFW Return Booster Pump	33,288	134	None			
51-T-1/2	Steam Turbine	8,621	64	None			
51-E-7	Surface Condenser	25,000	36	None			
51-P-2A	M.P. BFW Pump	33,288	134	None			
51-P-2B	M.P. BFW Pump	33,288	134	None			
51-G-1	Steam Turbine Generator	12,346	80	None			

*Storage points downstream of a component can affect the reliability and maintainability of a component as it is perceived by the downstream equipment. These points are identified on the Availability Block Diagram.

The surface condenser is a single-shell one-tube pass unit with divided water boxes. It handles flow from the MP power turbine and the HP BFW pump turbine. Noncondensable-gas removal and priming are accomplished by two positive-displacement rotary vacuum pumps. The condensate is pumped to the surge tank by a condensate pump.

The deaerator is a horizontal tray unit operating at 25 psia. Saturated conditions are maintained in the deaerator by the addition of 55-psia process steam supplied by the MP power turbine.

SUBSYSTEM AVAILABILITY = 98.387%

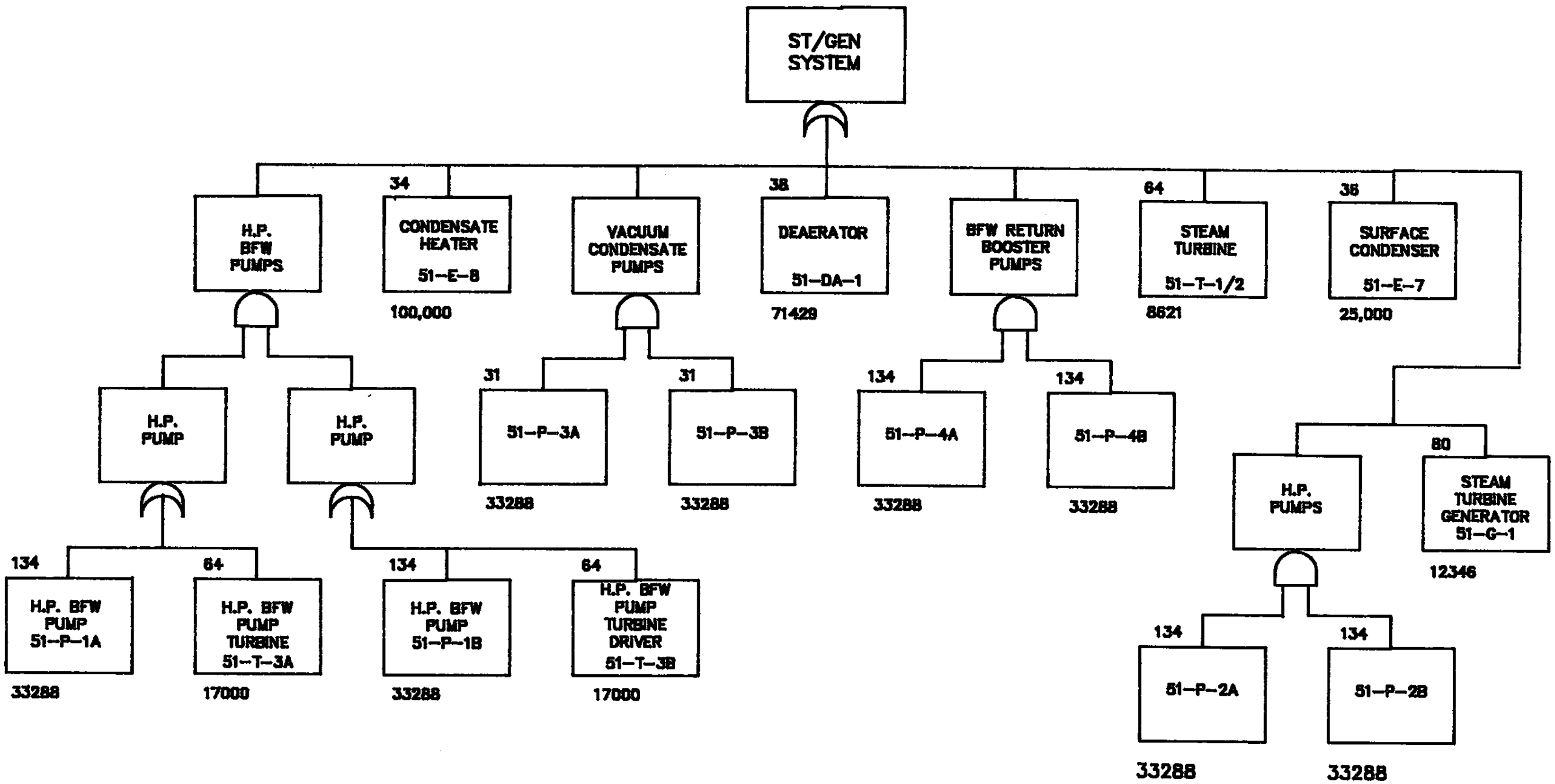


Figure 2-31. Steam Turbine/Generator System Fault Tree

Section 3

ANALYSIS RESULTS

BASELINE CASE ANALYSES

Baseline IGCC

Three different evaluations were performed for the Baseline IGCC plant design. The Baseline IGCC plant was designed such that the gas plant and the combustion turbines are matched in size at an ambient temperature of 20°F. Consequently, at 59°F ambient temperature, there is an 11.2-percent excess (or spare) gasification capacity. The excess gasification capacity at 59°F was applied to the system in the event of a gasifier failure. This condition was modeled by increasing the gasification capacity of each gasifier to reflect the fact that in the event of a gasifier failure, the remaining gasifiers would be operated at their full design output levels.

The availability block diagram, shown in Figure 2-1 in Section 2, is a pictorial representation of the "flow" of availability for the Baseline IGCC. The capacity percentage shown above each gasifier reflects the 11.2-percent gasification spare capacity, which is also reflected in the capacity values for the acid gas removal system.

Modeling of four different power-producing sections in one unit model, such as that depicted in Figure 2-1, is difficult. (In this IGCC design the four power producers include the three combustion turbines and the steam turbine.) Furthermore, the simultaneous failure of certain equipment often creates new plant output states. These interdependencies are impossible to model by using UNIRAM* alone in its present form. An approximation of these conditions can be modeled by using the UNIRAM final-state override capability. In an effort to model the unit accurately, ARINC Research submitted for evaluation to Fluor Engineers, Inc., the most probable

*UNIRAM is a computer model that facilitates reliability, availability, and maintainability analyses.

plant output states for each IGCC design. Fluor then developed performance data for these states. Tables 3-1 through 3-3 show the Fluor performance data for the three baseline cases. Greater detail with respect to some of the components of the Fluor calculation can be found in Appendix E.

Table 3-1

BASELINE IGCC PERFORMANCE DATA FOR
ALL OF THE MOST LIKELY FAILURE MODES

State	Descriptor	Power Output (MW)	Heat Rate (Btu/kWh)	Percentage of Moisture in Fuel Gas	Coal Feed Rate (ST/D)*	Natural Gas Feed Rate (MMSCF/D)**
1	No failures	598	8,890	29.3	4,997.5	---
2	1 HRSG fails	514	10,160	25.0	4,906.6	---
3	1 Gasifier fails	491	9,010	31.0	4,158.2	---
4	1 HRSG and 1 Gasifier fails	424	10,440	26.2	4,158.2	---
5	1 Combustion Turbine fails	391	9,310	33.0	3,416.3	---
6	2 Gasifiers fail	311	9,480	33.8	2,772.1	---
7	1 Acid Gas Removal fails	311	9,480	33.8	2,772.1	---

*Short tons per day.
**Millions of standard cubic feet per day.

Table 3-2

BASELINE IGCC WITH SUPPLEMENTAL FIRING PERFORMANCE DATA FOR THE UNIQUE AND MOST PROBABLE FAILURE MODES

State	Descriptor	Power Output (MW)	Heat Rate (Btu/kWh)	Percentage of Moisture in Fuel Gas	Coal Feed Rate (ST/D)*	Natural Gas Feed Rate (MMSCF/D)**
1	No failures	652	9,050	30.0	5,544.2	---
2	1 HRSG fails	573	10,300	25.8	5,544.2	---
5A	1 Combustion Turbine fails	468	9,670	33.0	4,252.4	---
5B	1 Combustion Turbine fails and 1 Gasifier fails	458	9,660	33.0	4,158.2	---
†	Other					

*Short tons per day.
**Millions of standard cubic feet per day.
†Other likely failure modes are already enumerated in Table 3-1.

Only those failure modes that had a probability of occurrence of approximately 1 percent or more of the time were examined by Fluor. Subsequently, the performance of those failure modes that had a lower than 1-percent likelihood of occurrence was approximated by ARINC Research and EPRI. From baseline case to case some of the failure modes are identical, both in terms of the identity of the failed equipment and the resulting plant performance. A complete enumeration of these states is presented in Tables 3-4, 3-5, and 3-6. For a more thorough definition of the available and the failed equipment in each state, refer to the detailed table in Appendix F.

Using the actual energy output values and the probability of being in each state, ARINC Research calculated the overall IGCC plant reliability measures. UNIRAM defined the probability of being in each state and showed which system(s) had failed in order to create the various derated output states. With knowledge of which systems had failed and of the energy output for those failures, accurate

Table 3-3

BASELINE IGCC WITH NATURAL GAS BACKUP PERFORMANCE
DATA FOR THE UNIQUE AND MOST PROBABLE FAILURE MODES

State	Descriptor	Power Output (MW)	Heat Rate (Btu/kWh)	Percentage of Moisture in Fuel Gas	Coal Feed Rate (ST/D)*	Natural Gas Feed Rate (MMSCF/D)**
3	1 Gasifier fails	584	8,745	32.3	4,158.2	16.1
4	1 Gasifier and 1 HRSG fail	498	10,000	26.5	4,158.2	13.2
6A	2 Gasifiers fail	556	8,530	37.0	2,772.1	42.5
7A	1 Acid Gas Removal fails	556	8,530	37.0	2,772.1	42.5
7B	1 Acid Gas Removal and 1 Combustion Turbine fail	390	8,820	35.6	2,772.1	11.6
†	Other					

*Short tons per day.
**Millions of standard cubic feet per day.
†Other likely failure modes are already enumerated in Table 3-1.

availability values could be calculated. Table 3-4 shows the states, probabilities, output levels, heat rates, and overall reliability measures for the Baseline IGCC analysis.

As can be seen from this table, the equivalent availability estimate for this Baseline IGCC is 86.18 percent, and the average heat rate (derived by weighting the heat rate at each state by the state's probability) is 9002 Btu/kWh. This "average" heat rate is 112 Btu/kWh higher than the design value. The average megawatt output while the plant is operating is a value that is also calculated by a weighting process. For the Baseline IGCC, this average output is 559 MW or 39 MW less than

Table 3-4

RELIABILITY RESULTS FOR THE BASELINE IGCC

State	Plant State**	State Probability (Percent)	Output Capability (Percent)	MW Output	Heat Rate (Btu/kWh)
1	No failures	71.59	100.00	598	8,890
2	1 HRSG fails	3.12	85.95	514	10,160
3	1 Gasifier fails	12.71	82.11	491	9,010
4	1 HRSG and 1 Gasifier fail	0.55	70.90	424	10,440
5	1 Combustion Turbine fails	6.01	65.38	391	9,310
6&7	2 Gasifiers fail and/or 1 Acid Gas fails	2.46	52.01	311	9,480
8	1 "Sat. Wtr. Htr. II" through "Air-Cooled System" fails	0.03	83.00	496*	11,000†
9	1 Oxygen Plant fails	0.18	51.10	306*	11,000†
10	3 Gasifiers fail	0.03	27.80	166*	11,000†
14	Entire Plant unavailable	3.32	0	0	N/A
		100.00			

*Not provided by Fluor Engineers, Inc.
**Listed are the capacity limiting failure(s) in each plant state.
†This heat rate of 11,000 Btu/kWh was used as a conservative estimate for all those failure modes not evaluated in detail by Fluor Engineers, Inc.

Effectiveness (Percent)	Forced Outage Rate (Percent)	Equivalent Forced Outage Rate (Percent)	Scheduled Outage Rate (Percent)	Equivalent Availability (Percent)	Availability (Percent)
90.43	3.32	9.57	4.70††	86.18	92.14

Average Heat Rate While Operating: 9,002 Btu/kWh
Average Output While Operating: 559 MW

††This scheduled outage rate derives from the Fluor Engineers, Inc. analysis reported in Appendix B. The ARINC Research analyses described in Section 4 yield scheduled outage rate estimates ranging from 5.8 percent to 8.8 percent, depending on the assumptions and maintenance philosophy employed.

Table 3-5

RELIABILITY RESULTS FOR THE BASELINE WITH SUPPLEMENTAL FIRING

State	Plant State**	State Probability (Percent)	Output Capability (Percent)	MW Output	Heat Rate (Btu/kWh)
1	No failures	71.59	100.00	652	9,050
2	1 HRSG fails	3.12	87.90	573	10,300
3	1 Gasifier fails	12.71	75.31	491	9,010
4	1 HRSG and 1 Gasifier fail	0.55	65.00	424	10,440
5A	1 Combustion Turbine fails	5.10	71.80	468	9,670
5B	1 Combustion Turbine and 1 Gasifier fail	0.91	70.25	458	9,660
6&7	2 Gasifiers fail and/or 1 Acid Gas fails	2.46	47.70	311	9,480
8	1 "Sat. Wtr. Htr. II" through "Air Cooled System" fails	0.03	83.00	541*	11,000†
9	1 Oxygen Plant fails	0.18	51.10	333*	11,000†
10	3 Gasifiers fail	0.03	25.00	163*	11,000†
14	Entire Plant unavailable	3.32	0	0	N/A
		100.00			

*Not provided by Fluor Engineers, Inc.
**Listed are the capacity limiting failure(s) in each plant state.
†This heat rate of 11,000 Btu/kWh was used as a conservative estimate for all those failure modes not evaluated in detail by Fluor Engineers, Inc.

Effectiveness (Percent)	Forced Outage Rate (Percent)	Equivalent Forced Outage Rate (Percent)	Scheduled Outage Rate (Percent)	Equivalent Availability (Percent)	Availability (Percent)
89.86	3.32	10.14	4.70††	85.64	92.14

Average Heat Rate While Operating: 9,147 Btu/kWh
Average Output While Operating: 606 MW

††This scheduled outage rate derives from the Fluor Engineers, Inc. analysis reported in Appendix B. The ARINC Research analyses described in Section 4 yield scheduled outage rate estimates ranging from 5.8 percent to 8.8 percent, depending on the assumptions and maintenance philosophy employed.

Table 3-6

RELIABILITY RESULTS FOR THE BASELINE WITH NATURAL GAS BACKUP

State	Plant State**	State Probability (Percent)	Output Capability (Percent)	MW Output	Heat Rate (Btu/kWh)
1	No failures	71.59	100.00	598	8,890
2	1 HRSG fails	3.12	85.95	514	10,160
3	1 Gasifier fails	12.71	97.66	584	8,745
4	1 HRSG and 1 Gasifier fail	0.55	83.26	498	10,000
5	1 Combustion Turbine fails	5.91	65.38	391	9,310
5C	1 Combustion Turbine and 1 unassociated HRSG fail††	0.18	46.82	280*	11,000†
6&7A	2 Gasifiers fail and/or 1 Acid Gas fails	2.46	92.98	556	8,530
7B	1 Combustion Turbine and 1 Acid Gas fail	0.10	65.22	390	8,820
8	1 "Sat. Wtr. Htr. II" through "Air-Cooled System" fails	0.03	97.66	584*	11,000†
9&10	1 Oxygen Plant fails or 3 Gasifiers fail††	0.21	75.25	450*	11,000†
11	2 HRSGs fail††	0.05	62.71	375*	11,000†
12	1 Steam Turbine fails	1.60	53.17	312*††	11,000†
13	2 Combustion Turbines fail††	0.15	29.26	175*	11,000†
14	Entire Plant unavailable	1.34	0	0	N/A
		100.00			

*Not provided by Fluor Engineers, Inc.
**Listed are the capacity limiting failures in each state.
†This heat rate of 11,000 Btu/kWh was used as a conservative estimate for all those failure modes not evaluated in detail by Fluor Engineers, Inc.
††The simplifying assumption for these cases is that the only fuel being used would be natural gas.

Effectiveness (Percent)	Forced Outage Rate (Percent)	Equivalent Forced Outage Rate (Percent)	Scheduled Outage Rate (Percent)	Equivalent Availability (Percent)	Availability (Percent)
94.56	1.34	5.44	3.20#	91.53	95.52

Average Heat Rate While Operating: 8,981 Btu/kWh
Average Output While Operating: 573 MW

#This scheduled outage rate can be derived from the Fluor Engineers, Inc. analysis reported in Appendix B. This outage rate represents the maintenance time required by the combined-cycle portion only of the IGCC.

the design plant output. The "average output while operating" can be related to the other plant reliability measures as follows:

$$\frac{\left[\begin{array}{c}\text{Average Output}\\ \text{While Operating, MW}\end{array}\right]}{\left[\begin{array}{c}\text{Design Plant}\\ \text{Output, MW}\end{array}\right]} = \frac{\left[\text{Equivalent Availability (\%)}\right]}{\left[1 - \begin{array}{c}\text{Scheduled}\\ \text{Outage}\\ \text{Rate}\end{array}\right] \times \left[1 - \begin{array}{c}\text{Forced}\\ \text{Outage}\\ \text{Rate}\end{array}\right]} \times \left[10^{-2}\right]$$

Baseline with Supplemental Firing

The analysis of the Baseline with Supplemental Firing differs from the Baseline IGCC analysis in that the excess gas produced by the gasifiers operating at 59°F was used to fire the HRSGs and produce supplemental steam. Thus, in effect, there is no spare gasification capacity. Under all modes of operation, a maximum quantity of fuel is fired by the combustion turbines, and any excess fuel gas is used to supplementally fire the HRSGs up to a maximum determined by the metal temperatures in the HRSGs. (See Figure 2-3.)

The addition of duct firing capability necessitated the inclusion of duct-firing reliability and maintainability data. Using the ERAS* data system, ARINC Research identified key components associated with the failure of duct firing systems. Table 3-7 shows the components modeled in the duct firing system and their reliability and maintainability data. Figure 3-1 is the fault tree for the duct firing system.

The difference between the Baseline IGCC and Baseline with Supplemental Firing models occurs in the combustion turbine/HRSG section of the plant. The process of supplemental firing creates excess or supplemental steam in the HRSGs, which increases the output of the steam turbine. The maximum plant output for Baseline with Supplemental Firing is 652 MW, compared with 598 MW for the Baseline IGCC. Table 3-5 shows the output states, probabilities, output levels, and reliability and maintainability measures for the Baseline with Supplemental Firing design. The equivalent availability, 85.64 percent, is lower than the equivalent availability for Baseline IGCC by 0.54 percentage points. Although the equivalent availability is lower, the design for the Baseline with Supplemental Firing is able to produce more power (based on its equivalent availability and maximum output) at 59°F ambient than the Baseline IGCC design. Table 3-8 shows the expected yearly output from

*ERAS stands for EPRI Reliability Assessment System. This is an availability data base for combined-cycle power plants.

Table 3-7

DUCT BURNER COMPONENT DATA

Component Name	Mean Time Between Failures (Hours)	Mean Downtime (Hours)
Burner	31,907.4	16.1
Piping	17,404.0	8.0
Flow Control	23,930.6	3.5

SUBSYSTEM AVAILABILITY = 99.889%

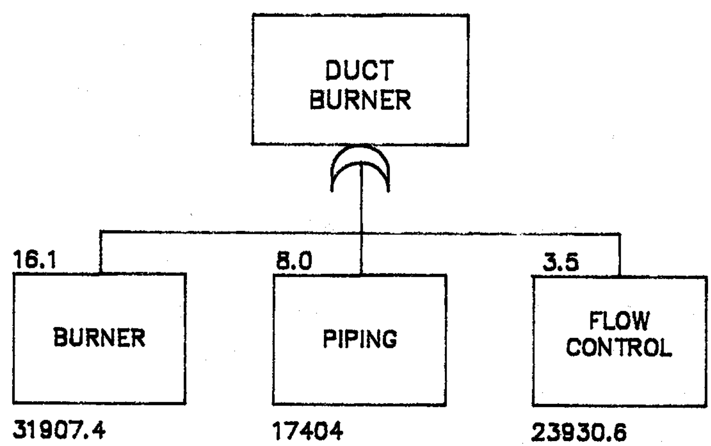


Figure 3-1. Duct Burner Fault Tree

each Baseline design in megawatt hours of production under the assumption that the plant is dispatched to the limit of its availability. The difference in output capability for the Baseline with Supplemental Firing amounts to a 380,000 MWh increase in production over Baseline IGCC.

Table 3-8

EXPECTED POWER PRODUCTION BASED ON UNIT-EQUIVALENT AVAILABILITY FOR THE BASELINE CASES

Case	Production* (MWh/Year)
Baseline IGCC	4,510,000
Baseline with Supplemental Firing	4,890,000
Baseline with Natural Gas Backup	4,790,000

$$^{*}\left(\begin{array}{c}\text{Production}\\ \text{MWh/yr}\end{array}\right) = \left(\begin{array}{c}\text{Average Output}\\ \text{While Operating, MW}\end{array}\right) \bullet \left(1 - \begin{array}{c}\text{Forced}\\ \text{Outage}\\ \text{Rate}\end{array}\right) \bullet \left(1 - \begin{array}{c}\text{Scheduled}\\ \text{Maintenance}\\ \text{Rate}\end{array}\right) \bullet \left(8{,}760\ \frac{\text{Hours}}{\text{Year}}\right)$$

This increase in output capability is attained at the expense of some capital cost and efficiency. While the operation of the Baseline IGCC with Supplemental Firing can include duct firing, this plant can also be operated without dispatching the supplemental firing portion of the plant. During operation under this latter operational alternative, the plant performance (both heat rate and capacity) as well as the plant reliability would be expected to be very similar to that of the Baseline IGCC. Consequently, the supplemental firing capability that distinguishes the two Baseline cases discussed so far has the net effect of increasing plant output, cost, and heat rate and accomplishes this at a lower relative equivalent availability. Through increasing the plant output, this supplemental firing capability has the important effect of reducing the utility system loss-of-load probability.

The evaluation of the availability implications of supplemental firing is not straightforward. Another way of approaching the analysis would have been to consider the supplemental firing capability of 54 megawatts as spare plant capacity, which can be used in the event of an IGCC partial outage for the purpose of enhancing the plant output and thus equivalent availability. From another perspective, this capacity can be considered as somewhat separate from the Baseline

IGCC. It then represents additional system capacity with its own availability characteristics, the presence of which can reduce the utility system loss-of-load probability.

Another factor that compounds the difficulty of measuring the availability implications of supplemental firing capability lies in the ambient temperature sensitivity of this capacity. In the Baseline IGCC, the supplemental firing capacity varies all the way from 0 MW at 20°F ambient to 74 MW at 88°F ambient. The value of this capacity to a utility will depend on the relationship between the ambient temperature at the plant site and the concurrent utility system load.

Baseline with Natural Gas Backup

The model of the Baseline with Natural Gas Backup assumed the ability to use backup natural gas firing for the combustion turbines when too little gasification capacity was available to supply the available combustion turbines with fuel gas. It was also assumed that there would be no supplemental firing of any fuel, neither natural gas nor coal gas.

The availability block diagram differs from that in the Baseline IGCC design because of the perfectly available source of natural gas to the combustion turbines. (See Figure 2-4.) Natural gas backup causes masking of the majority of all failures in the coal-receiving-through-gasification section of the plant. If the entire gasification section of the plant fails, the plant can operate as a conventional combined-cycle plant, losing only the heat input supplied to the steam side by the gasification unit. In addition, the combustion turbines can operate on natural gas in the simple-cycle mode even if several HRSGs fail. (In the other baseline cases, when more than one HRSG failed or when the steam turbine failed, the models assumed that the entire plant would shut down due to the plant's inability to condense all of the saturated steam that would otherwise be generated by the gasification section.) The number of possible plant operating states is increased because of the increased number of possible states in the combustion turbine section of the plant.

Tables 3-6 and 3-9 present the results of the Baseline with Natural Gas Backup analysis. The equivalent availability for this analysis is higher (91.53 percent) than in any other baseline case model. This increase is entirely due to the consideration of natural gas backup. This backup capability not only reduces the extent of the forced outages, but it also leads to a reduction in the scheduled outage rate to reflect the fact that the combined cycle can be operated even when the gas plant is on scheduled maintenance.

Distillate oil can also serve as a backup fuel for IGCC plants in place of natural gas. The overall plant equivalent availability in this alternative circumstance is expected to be similar to that of the Baseline with Natural Gas Backup. The combustion turbines within an IGCC will always be designed with dual fuel firing equipment in order to accommodate both coal gas and a startup fuel, such as natural gas or distillate oil. Additional equipment would be required if the second fuel is to be used not only as a startup fuel but also as a backup fuel. When either natural gas or distillate oil is the backup, the capital cost of the larger on-site natural gas pipeline or oil tankage is expected to be less than $10/kW (basis: EPRI report AP-4395). Consequently, the availability advantage of backup fuel can be acquired at low cost.

A utility generation planner must obtain availability estimates, both with and without backup fuel, in order to properly assess the operation of an IGCC plant on the utility system. The planner must also have a measure of the "fuel mix" consumed by the plant. Results in Table 3-9 indicate that a fuel (coal to natural gas) mix of 23:1 would be expected for the plant in the absence of any effects of dispatch. Since natural gas is more costly than coal, the natural gas-fired modes would be expected to be dispatched less frequently than the coal-fired modes of operation. Consequently, the fuel mix experienced by an actual IGCC plant operated under economic dispatch would likely be higher than the 23:1 estimate derived in this analysis.

SENSITIVITY STUDIES

A number of sensitivity studies were conducted in conjunction with the baseline case analyses. Table 3-10 shows the baseline cases for which the various sensitivity studies were performed.

Table 3-9

COMPARISON OF COAL GAS VERSUS NATURAL GAS CONSUMPTION
IN THE BASELINE WITH NATURAL GAS BACKUP CASE

State	Plant State	State Probability (Percent)	Output Capability (Percent)	MW Output	Millions of Btu/hr HHV Coal	Natural Gas
1	No failures	71.59	100.00	598	5,319.8	0
2	1 HRSG fails	3.12	85.95	514	5,223.0	0
3	1 Gasifier fails	12.71	97.66	584	4,426.4	677
4	1 HRSG and 1 Gasifier fail	0.55	83.26	498	4,426.4	555
5	1 Combustion Turbine fails	5.91	65.38	391	3,636.6	0
5C	1 Combustion Turbine and 1 unassociated HRSG fail**	0.18	46.82	280*	0	3,080
6&7A	2 Gasifiers fail and/or 1 Acid Gas fails	2.46	92.98	556	2,950.9	1,788
7B	1 Combustion Turbine and 1 Acid Gas fail	0.10	65.22	390	2,950.9	488
8	1 "Sat. Wtr. Htr. II" through "Air Cooled System" fails	0.03	97.66	584*	4,426.0	677
9&10	1 Oxygen Plant fails or 3 Gasi-fiers fail**	0.21	75.25	450*	0	4,950
11	2 HRSGs fail**	0.05	62.71	375*	0	4,125
12	1 Steam Turbine fails	1.60	53.17	312*	0	3,432
13	2 Combustion Turbines fail**	0.15	29.26	175*	0	1,925
14	Entire Plant unavailable	1.34	0	0	0	0

*Not developed by Fluor Engineers, Inc.
**The simplying assumption for these cases is that the only fuel being used would be natural gas.

Ratio of Coal to Natural Gas: 23:1

Table 3-10

BASELINE CASES FOR WHICH
SENSITIVITY STUDIES WERE PERFORMED

Sensitivity Study	Baseline IGCC	Baseline with Natural Gas Backup
IGCC with Additional Spare Gasification Capacity	X	X
IGCC with Alternate Design Basis	X	
IGCC with Alternate Storage Capability	X	
IGCC with Either Optimistic or Pessimistic Reliability Data	X	
IGCC with Alternate Treatment of Tail Gas Treating	X	

IGCC with Additional Spare Gasification Capacity

The first sensitivity study evaluated the reliability implications of additional spare gasification capacity. The coal throughput capacity of the Texaco system (from gasification through gas scrubbing) is not yet well defined. Current Texaco estimates suggest that the IGCC design reported in EPRI report AP-3486 has 12-percent spare gasification in this portion of the plant even at the design, 20°F ambient condition. In this sensitivity study the Baseline IGCC and the Baseline with Natural Gas Backup were modified to the extent that they each contained a total of 25-percent (instead of 11.2-percent) spare-gasification-through-scrubbing capacity. Table 3-11 summarizes the results of this study.

Figure 3-2 depicts the response of the Baseline IGCC equivalent availability to changes in spare gasification capacity. As the spare capacity increases, the equivalent forced outage rate decreases and the equivalent availability increases. It should be noted that as spare gasification capacity increases, the plant equivalent availability asymptotically approaches 90.2 percent. This trend indicates that even if the gasification section were perfectly available, the scheduled maintenance requirements and the unavailability of the balance-of-plant would limit the overall plant equivalent availability to 90.2 percent.

Table 3-11

SUMMARY OF RESULTS FOR THE IGCC WITH ADDITIONAL SPARE GASIFICATION CAPACITY

Spare Gasification Capacity (Percent)	Effectiveness (Percent)	Forced Outage Rate (Percent)	Equivalent Forced Outage Rate (Percent)	Scheduled Outage Rate (Percent)	Equivalent Availability (Percent)	Availability (Percent)
11.2 (Baseline IGCC)	90.43	3.32	9.57	4.70	86.18	92.14
25.0 (Sensitivity to the Baseline IGCC)	91.97	3.32	8.03	4.70	87.65	92.14
11.2 (Baseline IGCC with Natural Gas Backup)	94.56	1.34	5.44	3.20	91.53	95.52
25.0 (Sensitivity to the Baseline with Natural Gas Backup)	94.70	1.34	5.30	3.20	91.67	95.50

Once 33.3-percent spare gasification capacity exists in the plant, a full spare gasification train is available for use in facilitating the scheduled rebricking of gasifiers. If one gasifier at a given time is on scheduled maintenance for rebricking, the entire plant unavailability due to scheduled outages of the gasifiers can be eliminated. Thus, the discontinuity in the curve of Figure 3-2 reflects the change in the plant scheduled outage rate from 4.7 percent to 3.2 percent, which is attributable to the full spare gasifier.

The results of Figure 3-2 are based on the assumption that all gasifier maintenance is performed simultaneously until the point that one full spare gasifier is available. At this point, the gasifier rebricking is conducted by way of staggered maintenance scenario. An alternative approach might have been to examine a staggered maintenance scenario over the entire range of possible spare gasification capacities. A graph of this approach, similar to Figure 3-2, would not contain any discontinuities since the increase in spare gasification capacity would have a continuous effect on the gasifier-related scheduled outages.

The detailed results of this sensitivity to the Baseline IGCC are shown in Table 3-12. The detailed results of the sensitivity to the Baseline IGCC with Natural Gas Backup are shown in Table 3-13. Equivalent availability in this latter study increased by 0.14 percentage points over the reference case, from 91.53 percent to

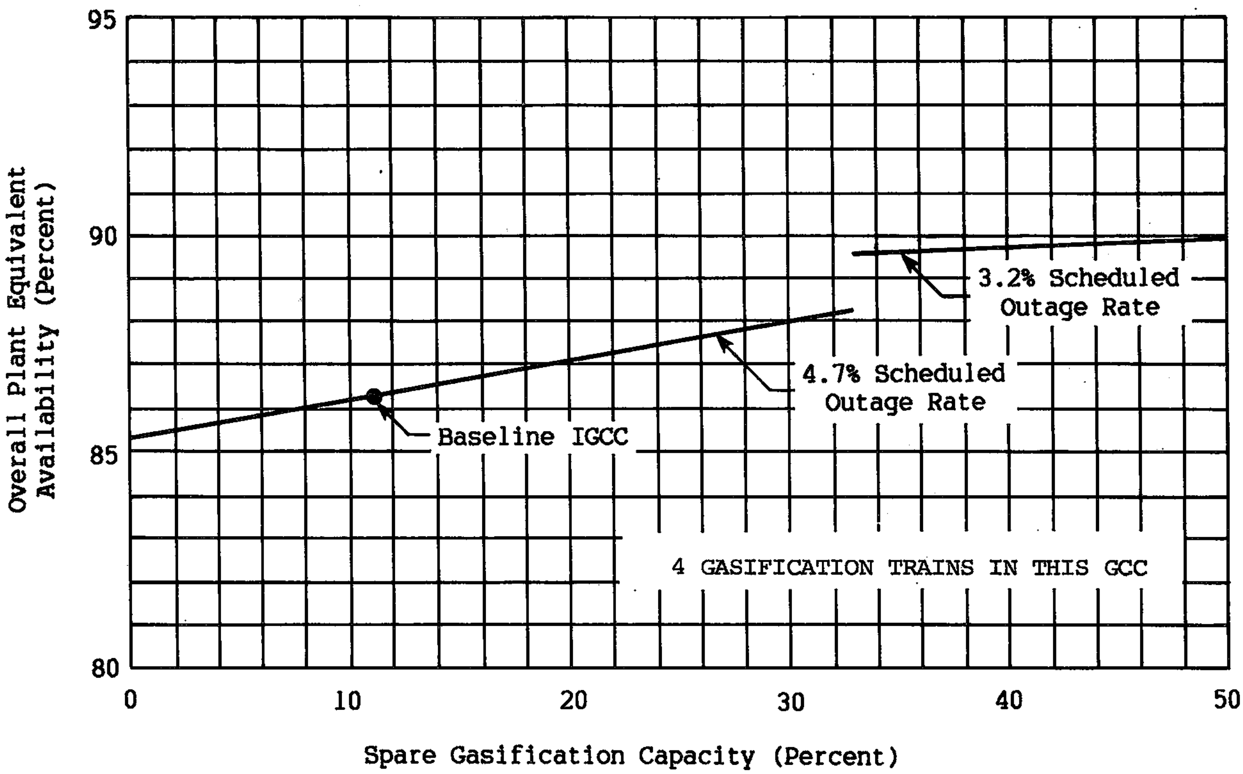


Figure 3-2. Impact of Spare Gasification Capacity

91.67 percent. This small increase amounts to a potential 7,334 MWh/year increase in plant production. (As in the referenced case, the sensitivity to the Baseline with Natural Gas Backup case had a scheduled outage rate of 3.2 percent used in the analysis.) The not-surprising conclusion which can be drawn here is that when the backup fuel firing capability of an IGCC is taken into account, the efficacy of spare gasification capacity diminishes.

IGCC with Alternate Design Basis

The sensitivity study entitled "IGCC with Alternate Design Basis" represents the operation of a plant designed such that the gas plant is sized to fully load the combustion turbines at an 88°F ambient temperature, but the plant is actually operated at a 59°F ambient temperature. At this 59°F ambient temperature, there is no spare gasification capacity. However, there is an 11.5-percent spare combustion turbine and HRSG capacity. The results of this study are presented in Table 3-14. Plant equivalent availability decreased from the baseline value by 0.22 percentage points from 86.18 percent to 85.96 percent. The lack of spare gasification capacity more than offsets the addition of spare combustion turbine/HRSG capacity, and

Table 3-12

DETAILED RESULTS FOR THE IGCC WITH ADDITIONAL SPARE GASIFICATION CAPACITY BUT WITHOUT BACKUP NATURAL GAS

(25% Spare Gasification Capacity)

State	Plant State	State Probability (Percent)	Output Capability (Percent)	MW Output
1	No failures	71.59	100.00	598
2	1 HRSG fails	3.12	85.95	514
3	1 Gasifier fails	12.71	92.46*	553*
4	1 HRSG and 1 Gasifier fail	0.55	81.25*	486*
5	1 Combustion Turbine fails	6.01	65.38	391
6&7	2 Gasifiers fail and/or 1 Acid Gas fails	2.46	58.91*	352*
8	1 "Sat. Wtr. Htr. II" through "Air-Cooled System" fails	0.03	83.00*	496*
9	1 Oxygen Plant fails	0.18	51.10	306
10	3 Gasifiers fail	0.03	31.25*	187*
14	Entire Plant unavailable	3.32	0	0
		100.00		

*Not provided by Fluor Engineers, Inc. Estimated instead by ARINC Research Corporation.

Effectiveness (Percent)	Forced Outage Rate (Percent)	Equivalent Forced Outage Rate (Percent)	Scheduled Outage Rate (Percent)	Equivalent Availability (Percent)	Availability (Percent)
91.97	3.32	8.03	4.70**	87.65	92.14

**This scheduled outage rate derives from the Fluor Engineers, Inc. analysis reported in Appendix B. The ARINC Research analyses described in Section 4 yield scheduled outage rate estimates ranging from 5.8 percent to 8.8 percent, depending on the assumptions and maintenance philosophy employed.

Table 3-13

DETAILED RESULTS FOR THE IGCC WITH ADDITIONAL SPARE GASIFICATION CAPACITY AND WITH BACKUP NATURAL GAS

(25% Spare Gasification Capacity)

State	Plant State	State Probability (Percent)	Output Capability (Percent)	MW Output
1	No failures	71.59	100.00	598
2	1 HRSG fails	3.12	85.95	514
3	1 Gasifier fails	12.71	99.16*	593*
4	1 HRSG and 1 Gasifier fail	0.55	84.95*	508*
5	1 Combustion Turbine fails	5.91	65.38	391
6&7A	2 Gasifiers fail and/or 1 Acid Gas fails	2.46	94.15*	563*
7B	1 Combustion Turbine and 1 Acid Gas fail	0.10	65.22	390
8	1 "Sat. Wtr. Htr. II" through "Air-Cooled System" fails	0.03	99.16*	593*
9&10	1 Oxygen Plant fails or 3 Gasifiers fail**	0.21	75.25*	450*
11	2 HRSGs fail**	0.05	62.71*	375*
12	1 Steam Turbine fails	1.60	53.17	312
13	2 Combustion Turbines fail**	0.15	29.26*	175*
14	Entire Plant unavailable	1.52	0	0
		100.00		

*Not provided by Fluor Engineers, Inc. Estimated instead by ARINC Research Corporation.
**The simplifying assumption for these cases is that the only fuel being used would be natural gas.

Effectiveness (Percent)	Forced Outage Rate (Percent)	Equivalent Forced Outage Rate (Percent)	Scheduled Outage Rate (Percent)	Equivalent Availability (Percent)	Availability (Percent)
94.70	1.34	5.30	3.20†	91.67	95.50

†This scheduled outage rate can be derived from the Fluor Engineers, Inc. analysis reported in Appendix B. This outage rate represents the maintenance time required by the combined-cycle portion only of the IGCC.

Table 3-14

RESULTS FROM THE IGCC WITH THE ALTERNATE DESIGN BASIS

Design Basis/ Operating Basis	Effectiveness (Percent)	Forced Outage Rate (Percent)	Equivalent Forced Outage Rate (Percent)	Scheduled Outage Rate (Percent)	Equivalent Availability (Percent)	Availability (Percent)
20°F/59°F	90.43	3.32	9.57	4.70	86.18	92.14
88°F/59°F	90.20	3.32	9.80	4.70	85.96	92.14

as a consequence, the equivalent availability decreased in this design sensitivity study relative to the Baseline IGCC design.

IGCC with Alternate Storage Capability

Several storage points were modeled in the Baseline IGCC reliability and maintainability evaluation. Through a sensitivity study, the advantages of storage were quantified by evaluating the equivalent availability of the plant after modifying the size of the storage capacity.

The equivalent availability of the plant when there is no storage except the coal pile (or storage point 1) is 84.53 percent as compared with 86.18 percent for the Baseline IGCC with its assumed storage capacities. Because this availability analysis ignores the potential effects of labor strikes that could lead to disruptions in coal supply, the impact of the coal pile on overall plant availability is very small. Three other storage points were evaluated and found to be relatively insignificant and were therefore not used in the sensitivity study. These three storage points affect the boiler feedwater subsystem and are numbered 7, 8, and 9 on the availability block diagram of Figure 2-1. Figures 3-3 through 3-7 are plots of equivalent availability versus storage time for the five remaining storage points.

The storage time for each storage point was increased from 0 to 60 hours to determine the impact of storage capacity in that particular location. All other storage points were held constant at their baseline values while each individual storage point was examined.

These graphs can be used to identify and quantify the effects of sensitive storage points. For example, the existence of oxygen plant storage in the baseline case

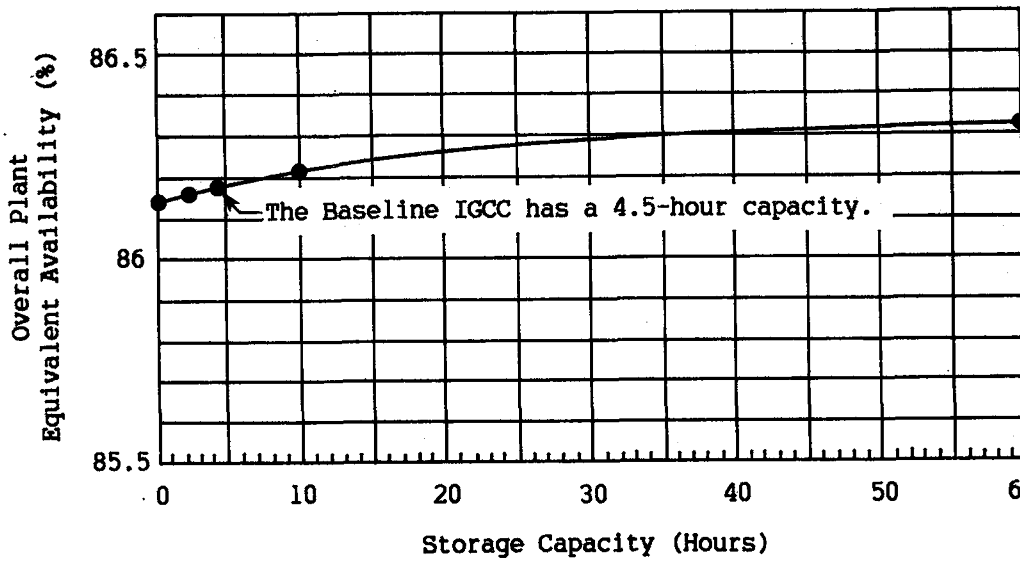


Figure 3-3. Storage Point 2 (Mill Feed Bin)

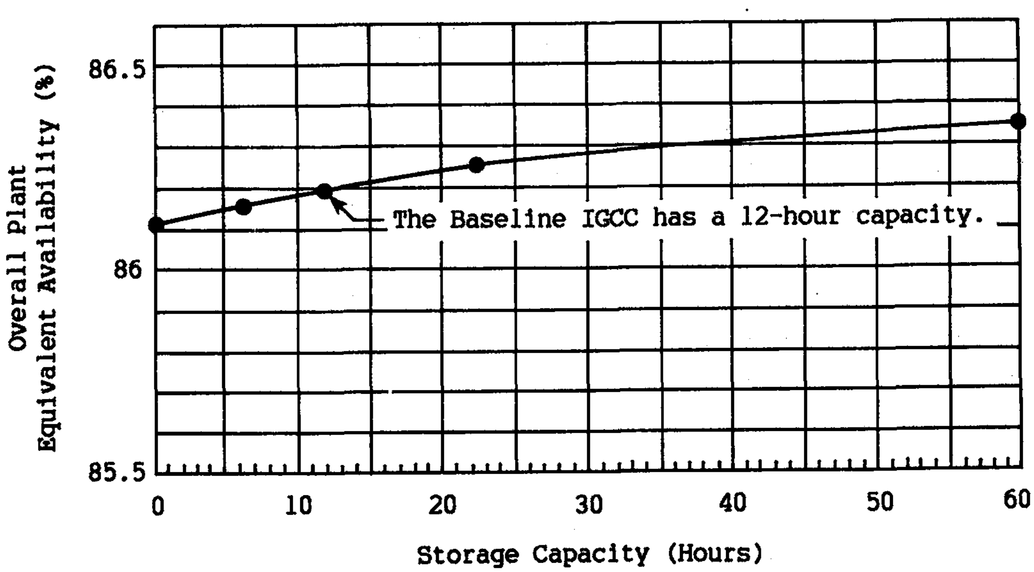


Figure 3-4. Storage Point 3 (Slurry Tank)

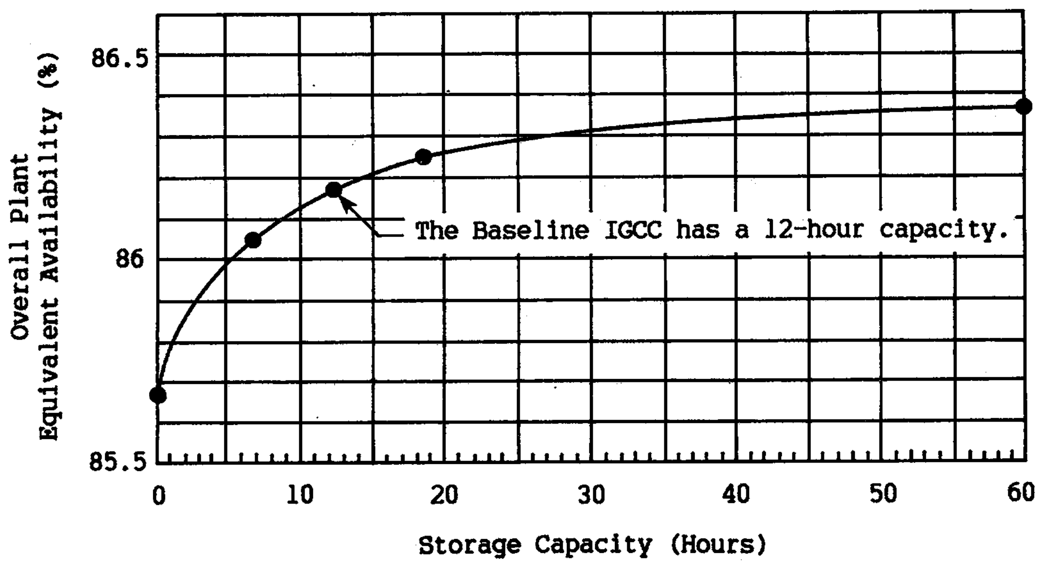


Figure 3-5. Storage Point 4 (Slurry Surge Tank)

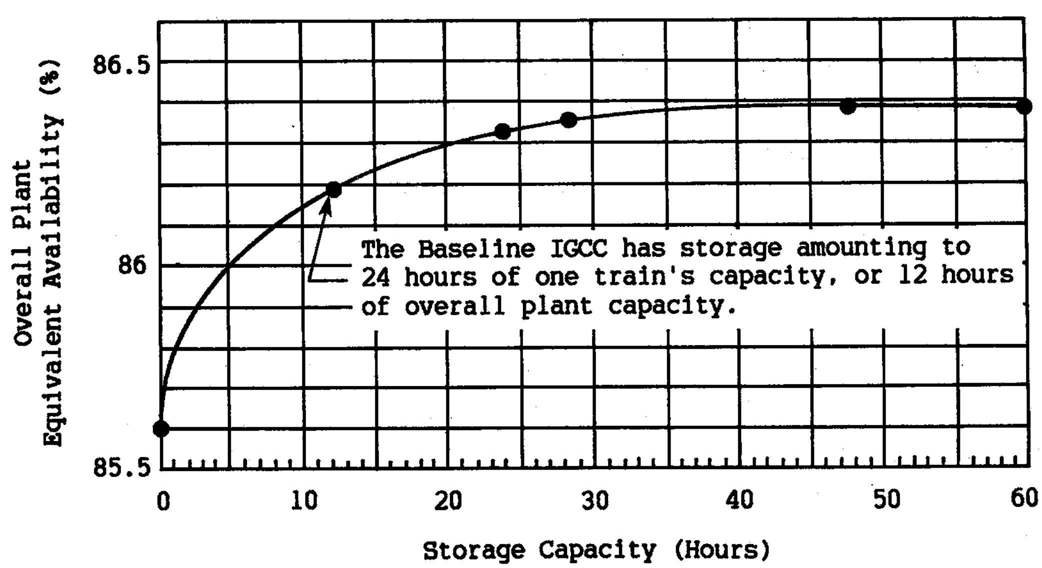


Figure 3-6. Storage Point 5 (Oxygen Plant)

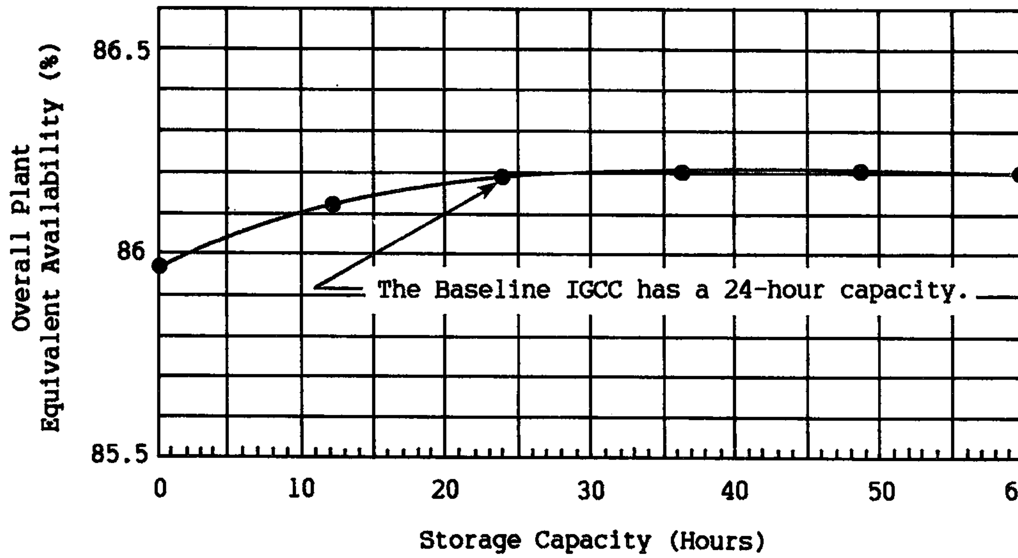


Figure 3-7. Storage Point 6 (Wastewater Treating)

improves the equivalent availability of the entire plant by approximately 0.6 percentage point. Storage point 4 (slurry surge tank) has the second greatest impact on plant equivalent availability, primarily because it affects more downstream subsystems than any other storage point in the plant. Figure 3-5 shows that if the total 12-hour capacity of storage point 4 were eliminated and all other storage points held at their baseline values, plant equivalent availability would decrease by approximately 0.5 percentage point from the baseline value. Figure 3-5 further indicates that if a 60-hour slurry surge tank were installed, a gain of approximately 0.2 percentage point in equivalent availability could be expected. Production values, together with economic variables, can be used to develop cost-benefit ratios for increasing or decreasing storage time and determining the optimum value.

One important consideration to keep in mind when examining the results of these storage calculations is that these storage analyses are only as accurate as the reliability input data. In particular, the estimates of component mean downtime appearing in this report and used in the storage analyses reflect only to varying degrees the estimated plant shutdown and startup time associated with a plant failure. As such, these mean downtime input values are merely estimates, and the resulting storage analysis results are only preliminary.

IGCC with Either Optimistic or Pessimistic Gasification Reliability Data

Through a sensitivity study the uncertainty in the reliability and maintainability (R&M) characteristics of the gasification-through-gas-scrubbing section of the IGCC plant design was quantified. Since this section of the plant represents state-of-the-art commercial technology, with which there is currently only limited operating experience, there remains considerable uncertainty about the actual reliability characteristics to be expected from a mature commercial plant. In this sensitivity study, two analyses were performed in an attempt to bracket the technology: pessimistic and optimistic. The reliability and maintainability estimates for both of these cases were supplied by Texaco, Inc. Modifications to the Fluor maintenance plan in the area of the gasifier rebricking schedule were made in order to reflect a pessimistic assumption with respect to the refractory life. In the pessimistic case, the refractory was scheduled for hot face rebricking every year (instead of the baseline assumption of every 1-1/2 years). The complete rebricking was performed every third rebricking as in the Baseline Schedule. In the optimistic case, rebricking occurred at the same frequency as the baseline case.

The analysis results are presented in Tables 3-15 and 3-16. In the case of the pessimistic gasification plant reliability characterization, the equivalent forced outage rate increased from a baseline estimate of 9.57 percent to 10.85 percent. However, the higher scheduled outage rate in this pessimistic case was responsible for more than two-thirds of the decrease in equivalent availability from the baseline estimate of 86.18 percent to 82.38 percent. The optimistic reliability and maintenance assumptions lead to an equivalent availability estimate of 87.03 percent. All of the 0.85 percentage-point rise in this estimate over the baseline is attributable to a reduction in the equivalent forced outage rate.

An uncertainty analysis, using the optimistic, pessimistic, and most likely component R&M values, was also performed. The uncertainty analysis calculates the 90-percent confidence interval for equivalent availability on the basis of a three-parameter distribution defined by the pessimistic, optimistic, and baseline R&M data. The uncertainty analysis addresses the combined effects of high, low, and average R&M values on unit performance. Table 3-17 presents the results of this analysis, including the 90-percent confidence interval (based on 30 samples) for all plant R&M values.

The difference between the equivalent forced outage rate in the pessimistic and optimistic cases is 2.2 percentage points. The uncertainty analysis showed the confidence interval for equivalent forced outage rate to be from 9.56 percent to

Table 3-15

RESULTS FOR THE IGCC WITH PESSIMISTIC GASIFICATION RELIABILITY DATA

State	Plant State	State Probability (Percent)	Output Capability (Percent)	MW Output
1	No failures	66.26	100.00	598
2	1 HRSG fails	2.89	85.95	514
3	1 Gasifier fails	17.16	82.11	491
4	1 HRSG and 1 Gasifier fail	0.75	70.90	424
5	1 Combustion Turbine fails	5.95	65.38	391
6&7	2 Gasifiers fail and/or 1 Acid Gas fails	3.38	52.01	311
8	1 "Sat. Wtr. Htr. II" through "Air-Cooled System" fails	0.03	83.00	496*
9	1 Oxygen Plant fails	0.18	51.10	306*
10	3 Gasifiers fail	0.08	27.80	166*
14	Entire Plant unavailable	3.32	0	0
		100.00		

*Not provided by Fluor Engineers, Inc.

Effectiveness (Percent)	Forced Outage Rate (Percent)	Equivalent Forced Outage Rate (Percent)	Scheduled Outage Rate (Percent)	Equivalent Availability (Percent)	Availability (Percent)
89.15	3.32	10.85	7.60**	82.38	89.33

**This scheduled outage rate is based on a one-year gasifier refractory life.

Table 3-16

RESULTS FOR THE IGCC WITH OPTIMISTIC GASIFICATION RELIABILITY DATA

State	Plant State	State Probability (Percent)	Output Capability (Percent)	MW Output
1	No failures	75.58	100.00	598
2	1 HRSG fails	3.30	85.95	514
3	1 Gasifier fails	9.16	82.11	491
4	1 HRSG and 1 Gasifier fail	0.40	70.90	424
5	1 Combustion Turbine fails	6.04	65.38	391
6&7	2 Gasifiers fail and/or 1 Acid Gas fails	1.98	52.01	311
8	1 "Sat. Wtr. Htr. II" through "Air-Cooled System" fails	0.03	83.00	496*
9	1 Oxygen Plant fails	0.18	51.10	306*
10	3 Gasifiers fail	0.01	27.80	166*
14	Entire Plant unavailable	3.32	0	0
		100.00		

*Not provided by Fluor Engineers, Inc.

Effectiveness (Percent)	Forced Outage Rate (Percent)	Equivalent Forced Outage Rate (Percent)	Scheduled Outage Rate (Percent)	Equivalent Availability (Percent)	Availability (Percent)
91.32	3.32	8.68	4.70**	87.03	92.14

**This scheduled outage rate derives from the Fluor maintenance plan in Appendix B.

Table 3-17

RESULTS OF THE GASIFICATION
RELIABILITY DATA UNCERTAINTY ANALYSIS

Effectiveness (Percent)	Forced Outage Rate (Percent)	Equivalent Forced Outage Rate (Percent)
90.43 ± 0.02	3.32 ± 0.00	9.57 ± 0.01

9.57 percent. The confidence interval is much smaller than the interval calculated from the pessimistic and optimistic analyses, since the uncertainty analysis accounts for the counteracting effects of potential R&M values throughout the uncertainty range, whereas the pessimistic and optimistic analyses do not. A more detailed description of this uncertainty analysis can be found in Appendix G.

IGCC with Alternate Treatment of Tail Gas Treating

The final sensitivity study evaluated the impact on plant equivalent availability of not being able to flare tail gas when the tail gas treating system is unavailable. This kind of operating restriction might arise as a consequence of environmental regulations. In the baseline case model, the tail gas treating and flare systems were modeled in parallel with each other. To determine the availability impact of not being able to flare tail gas, the flare subsystem was eliminated from the analysis. In this way, a failure of the tail gas treating system would cause a failure of the entire IGCC plant. The results of this sensitivity study are shown in Table 3-18. Equivalent availability decreased by 1.15 percentage points to 85.03 percent.

CRITICALITY RANKINGS

In order to ascertain which sections of the IGCC plant contribute most to the plant unavailability, the sections (or subsystems) were ranked according to their criticality. Table 3-19 shows a listing of subsystem criticality. This list is based on the impact that each subsystem would have on the plant equivalent forced outage rate if the subsystem were to be made perfectly available. Notice that the gasification section is the most critical component for the Baseline IGCC case, but

Table 3-18

RESULTS FOR THE IGCC WITH ALTERNATE TREATMENT OF TAIL GAS TREATING

State	Plant State	State Probability (Percent)	Output Capability (Percent)	MW Output
1	No failures	70.63	100.00	598
2	1 HRSG fails	3.08	85.95	514
3	1 Gasifier fails	12.53	82.11	491
4	1 HRSG and 1 Gasifier fail	0.55	70.90	424
5	1 Combustion Turbine fails	5.93	65.38	391
6&7	2 Gasifiers fail and/or 1 Acid Gas fails	2.43	52.01	311
8	1 "Sat. Wtr. Htr. II" through "Air-Cooled System" fails	0.03	83.00	496*
9	1 Oxygen Plant fails	0.18	51.10	306*
10	3 Gasifiers fail	0.03	27.80	166*
14	Entire Plant unavailable	4.61	0	0
		100.00		

*Not provided by Fluor Engineers, Inc.

Effectiveness (Percent)	Forced Outage Rate (Percent)	Equivalent Forced Outage Rate (Percent)	Scheduled Outage Rate (Percent)	Equivalent Availability (Percent)	Availability (Percent)
89.22	4.61	10.78	4.70**	85.03	90.91

**This scheduled outage rate derives from the Fluor Engineers, Inc. scheduled maintenance plan in Appendix B.

Table 3-19

CRITICALITY RANKING

Subsystem	Expected EFOR Decrease if Subsystem Were Perfectly Available: Baseline IGCC (Percent)	Expected EFOR Decrease if Subsystem Were Perfectly Available: Baseline With Natural Gas Backup (Percent)
Gasification High-Temperature Gas Cooling, Scrubbing	2.79	N/A
Combustion Turbine, Generator	2.19	2.22
Steam Turbine, Generator	1.49	.68
Ash Dewatering	.69	N/A
HRSG	.66	.60
Acid Gas Removal	.65	N/A
All Others	<.65	<.57

that for the Baseline with Natural Gas Backup case, the most critical component is the combustion turbine.

At times, a design engineer is faced with the need to redesign a plant in order to increase or decrease plant reliability in the best fashion possible. Alternatives at the engineer's disposal include: 1) modifying the subsystem or component spare capacity in the plant, 2) specifying components with different reliability characteristics, and 3) modifying the capacity of the intermediate storage points. In order to accomplish this redesign the engineer needs to know the subsystem criticality rankings as well as the economics of any design change. Table 3-19 provides the first of these two input requirements. However, the second element, the cost estimates, is beyond the scope of this study.

Section 4

IGCC MAINTENANCE PLAN EVALUATION

SCHEDULED PLANT MAINTENANCE PLAN FOR THE IGCC PLANT DESIGN

ARINC Research analyzed and evaluated the scheduled maintenance plan for the integrated gasification-combined-cycle (IGCC) design provided by EPRI. The objectives of the analysis were as follows:

- To evaluate durations of individual scheduled maintenance actions for the combined-cycle portion of the IGCC
- To evaluate the effect that forced outage shadowing could have on plant scheduled outage time
- To evaluate the plant scheduled maintenance requirements

The scheduled maintenance (SM) durations (used in Section 3 of this report) for the IGCC plant design were developed by Fluor Engineers, Inc. with input from Texaco, Inc. on the gasification plant section and from General Electric Company on the combined-cycle section. The Fluor overall plant scheduled maintenance estimate is based on estimates for the expected duration and the recommended frequency for each scheduled maintenance action. These estimates are detailed in Appendix B.

Using the Fluor analysis as a starting point, ARINC Research adjusted some of the maintenance activity durations and subsequently generated several possible IGCC maintenance scenarios. First, ARINC Research compiled data from the EPRI Reliability Assessment System* (ERAS) to determine actual maintenance downtime experience for combustion turbines. The ERAS data base contains operational and maintenance data for 28 industrial combustion turbines in combined-cycle applications. ARINC Research then modified the Fluor maintenance estimates for the conventional combined-cycle equipment in accordance with the ERAS values; however, ARINC Research did not adjust the Fluor estimates for gasifier maintenance.

*This system was developed under EPRI project RP-990 and has been reported in AP-3420.

Once having adjusted maintenance durations for certain activities, ARINC Research then proceeded to devise several scheduled maintenance plan alternatives. Special attention was applied to "synchronizing" the actions in order to obtain a high degree of maintenance overlap, since greater overlap of SM actions results in fewer hours of lost production.

Overlap is increased first by adjusting the position (in time) of SM actions with respect to each other and without changing their frequencies. The only limitation to this positioning of SM actions occurs if simultaneous actions exceed available manpower or if they are limited by the physical configuration of plant components. For purposes of this study it was assumed that neither manpower nor equipment configuration was a limiting factor.

Overlap may also be increased by changing the frequency of SM actions. This method requires caution. If the frequency is decreased, there is a risk of a premature component failure caused by a delay in scheduled maintenance. If the frequency is increased, the resulting increase in outage hours may be greater than the outage hours saved by the overlap.

Efficiencies in SM actions can also be achieved by taking advantage of the random occurrences of forced outages. Specifically, when a plant outage occurs, SM actions that were imminent could be performed simultaneously with the corrective action, albeit a little early. An analytical approach to determining the amount of maintenance efficiency that can be gained by taking advantage of forced outages was formulated and applied to the Fluor SM activities. Three essential parameters were required for the analysis: (1) mean time between full forced outages (MTBFFO), (2) mean downtime of full forced outages (MDTFFO), and (3) the interval, or window, during which the SM initiation could be advanced or delayed to synchronize the action with a forced outage that may occur. If no forced outage occurs, the SM action is delayed until the end of the interval.

EVALUATION OF SCHEDULED MAINTENANCE ACTIVITY DURATIONS

ARINC Research's first task was to evaluate the maintenance requirements of the combustion turbines.

Combustion Inspection Durations

The ERAS Data Base contained information on 23 combustion inspections of General Electric MS 7000 B and C Model Turbines. The average duration for a combustion inspection was 243.7 hours. The minimum and maximum durations were 16 hours and

648 hours, respectively. Figure 4-1 shows the distribution of combustion inspection durations from this data base. Three inspections had a duration of 648 hours, because they were performed concurrently, and labor or parts availability constrained the inspections. If these three inspections are not considered, the average duration becomes 183.2 hours.

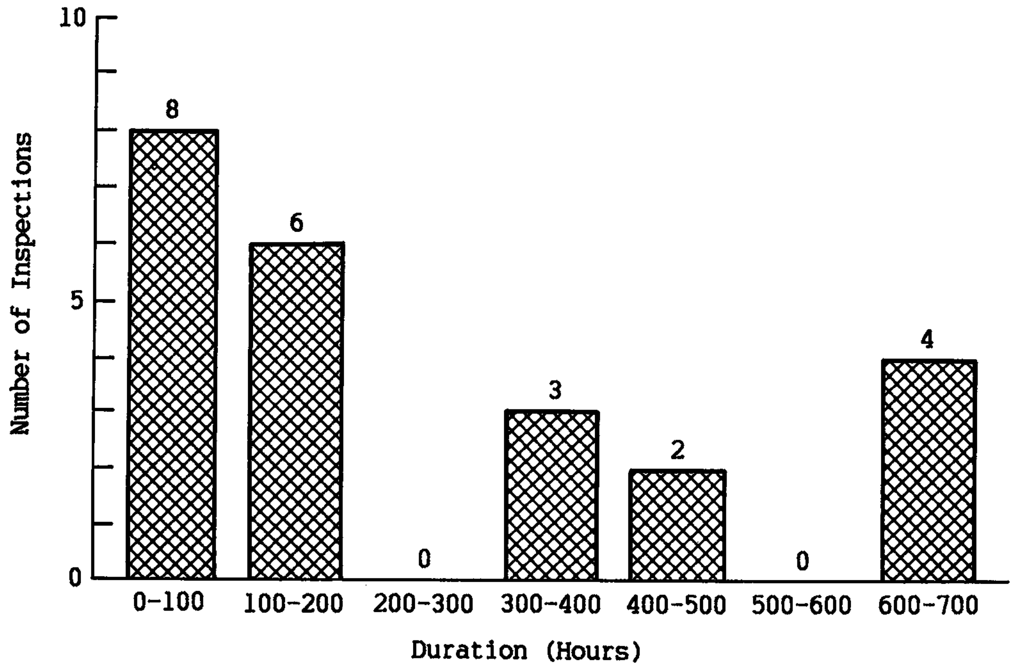


Figure 4-1. Combustion Turbine Inspection Durations for General Electric MS 7000 Combustion Turbines*

*Source: EPRI Reliability Assessment System (ERAS).

A combustion inspection is required to identify and correct incipient failures such as cracks in combustion liners, crossfire tubes, fuel nozzle erosion, or transition-piece seal wear. The short-duration inspections represent inspections in which no defects were detected. The long-duration inspections represent cases in which replacement parts were unavailable to support rapid turnaround. A 183-hour inspection duration is a representative value for utility practices with labor and parts availability considered.

The IGCC design under consideration in this study includes advanced combustion turbines that will differ in configuration from the MS 7000 B and C Model Turbines represented in the data base. It is understood that the advanced combustion turbines being designed by General Electric (G.E.) will incorporate some maintainability enhancements over existing units. These enhancements may tend to reduce the inspection durations slightly. It is also understood, however, that the number of combustion chambers will be increased, which will tend to increase inspection durations. For these counteracting reasons a significant change in the combustion turbine inspection durations is not expected.

The final issue in combustion inspection durations is the utility maintenance strategy. Current utility practice is to perform scheduled maintenance on straight time with limited use of overtime, typically five or six days per week, at ten hours per day. Multiple-shift maintenance is normally not performed, because of the critical nature of the maintenance. It is important to have qualified technical supervision on site during combustion inspections for quality assurance and control functions, and the unavailability of supervisory personnel for multiple shifts can limit the effectiveness of multiple shifts. Improperly inspected or installed combustion components may cause a forced outage or catastrophic failure of much greater significance than a two- or three-day saving in scheduled outage durations.

One factor that distinguishes combustion turbines within an IGCC plant from the turbines for which historical experience has provided a data base lies in the fact that IGCC plants would be baseload units on a utility system. As such, their criticality to a utility in its ability to meet system load is greater than combustion turbines in peaking or intermediate load service. As a consequence, the maintenance strategy of these units might differ and thus lead to a reduction in the combustion inspection duration. Nevertheless, it was conservatively assumed that a scheduled combustion inspection for the IGCC will have an average duration of 183 hours under typical utility maintenance policies and strategies.

Hot-Gas-Path Inspection Durations

Six hot-gas-path inspections of G.E. MS 7000 Turbines were recorded in the ERAS Data Base. The average duration was 1304.7 hours, the minimum 750 hours, and the maximum 2435 hours. The durations of hot-gas-path inspections are highly sensitive to the availability of a spare turbine rotor. The capital cost of a spare rotor is significant, and economic analyses performed in the past by ARINC Research for electric utilities have indicated that a spare rotor is a cost-justifiable acquisition for baseloaded plants with three or more combustion turbines. This conclusion is highly sensitive to the cost of replacement power for the specific plant.

The utilities that contribute to the ERAS data generally do not stock spare rotors. The 1304-hour average duration for a hot-gas-path inspection is almost double the length of the shortest duration, 750 hours, suggesting that spare parts are not in stock most of the time. Stocking a spare rotor and turbine nozzle segments will reduce hot-gas-path inspection durations by approximately four weeks, for a total duration of approximately 630 hours [calculated as follows: 1304 hours - (4 weeks) (7 days/week)(24 hours/day) = 632 hours]. However, pursuit of this maintenance philosophy raises significant issues that must be addressed.

The only way to optimize use of spare rotors and turbine nozzles is to stagger the scheduled maintenance actions. If hot-gas-path inspections are to be performed concurrently, the spare rotor can be utilized only for one unit, and the inspection durations for the other units will be extended while rotor and nozzle repairs are made. To properly analyze the trade-offs between staggered maintenance and concurrent maintenance, the availability of spare parts must be considered.

For the IGCC plant analyses, two scenarios were considered: staggered maintenance and concurrent maintenance. Staggered maintenance will result in an average downtime of 630 hours, reflecting optimal utilization of spare hot-gas-path components. If hot-gas-path inspections are to be performed concurrently, an average duration of 1300 hours is more representative. On the basis of the capital costs of the spares, it would be extremely difficult to justify three complete sets of hot-gas-path spares to service three combustion turbines.

Major Overhaul Durations

The ERAS Data Base does not contain a sufficient number of major overhauls to permit calculating a credible average duration. ARINC Research did perform a reliability and maintainability audit of the T.H. Wharton Plant, Houston Lighting and Power, which is documented in EPRI report AP-3495. For ten major overhauls examined in the audit, the average duration was 1770 hours. These overhauls were performed without the use of spare rotors; with a spare rotor, an average duration of 1098 hours is more representative. Again, the 1098-hour duration assumes staggered maintenance. This 1098-hour value is calculated as follows: 1770 hours minus 672 hours' logistics time. The average overhaul duration is therefore 45.8

days. The primary difference between hot-gas-path inspections and major overhauls is the reworking of the compressor section and the removal of the generator field.

Perspective from General Electric Company

Upon review of the maintenance durations used by ARINC Research in this study, General Electric (G.E.) Company provided several illuminating comments. They noted that the key issue determining the maintenance duration for various combustion turbine-related activities is whether single or multiple labor shifts are used for maintenance. While the ARINC Research analysis assumes one 10-hour shift, G.E. would assume two 8-hour shifts per day. This shift selection is a matter of operator choice. If the combustion turbine maintenance is not a critical path activity, then indeed the lower labor loading would be used. However, G.E. maintains that when the activities do fall on the critical path, then the maintenance can be accomplished within the G.E./Fluor allotted time shown in Table 4-1.

Table 4-1

COMPARISON OF G.E. AND ARINC RESEARCH DATA

	G.E./Fluor Estimates*		ARINC Research Estimates**	
	Duration (Hours)	Labor (Hours)	Duration (Hours)	Labor (Hours)
Combustor Inspection	105	64	180	65
Hot-Gas-Path Inspection	240	160	630	230
CT Major Overhaul	460	320	1098	400

*Based on ORAP data and two 8-hour shifts, 7-day work week, assuming: inspection pre-planned, flange-to-flange turbine only, crew with average tradeskill, part replacement only (part repair completed for spares inventory), all parts and tools available.
**Based on ERAS data and on one 10-hour shift, 5-day work week.

The G.E. data base from which this information derives is called "ORAP," which stands for Operational Reliability Analysis Program. It consists of actual operating data from utility and industrial combustion turbines. Taking the combustor inspection as an example, the ORAP data base, as shown in Figure 4-2,

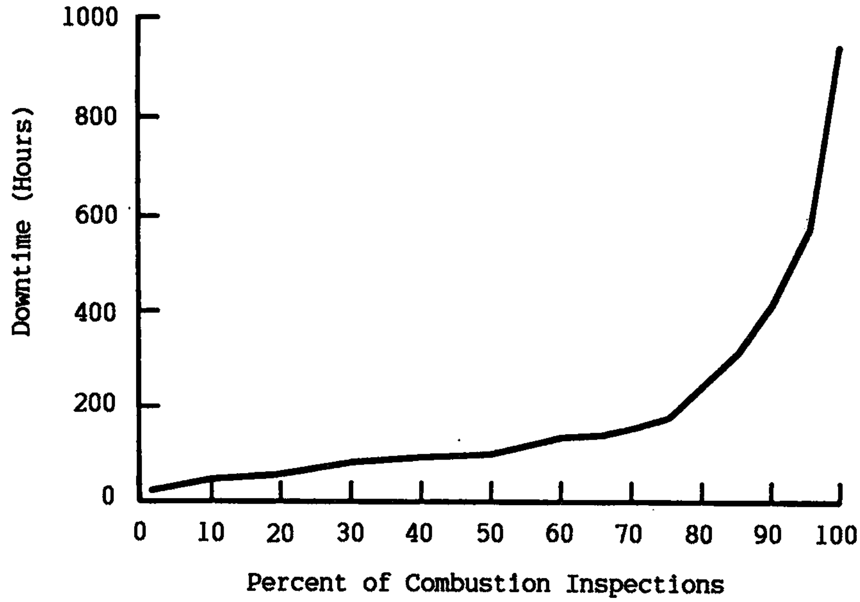


Figure 4-2. Distribution of MS 7000 Combustion Inspection Downtime

Data Source: Baseload MS 7000 ORAP Data. GT 15,932

illustrates that over 50 percent of actual combustion inspections, from customers judged to be good outage managers, are completed within a 105-hour time period. Thus, the G.E./Fluor estimates can be achieved if in fact there is an incentive to do so. If there is no incentive, then the ARINC Research estimates are adequate.

MAINTENANCE SCHEDULES

Upon completion of the ARINC Research data development effort, the original Fluor scheduled maintenance plan was reviewed. The Fluor plan, reproduced here as Appendix B and summarized on page B-8, was evaluated for potential revisions necessitated both by changes in maintenance action durations and by alternative assumptions with respect to the length of the time "windows" for accomplishing each scheduled maintenance activity. (These time "windows" capture the extent of flexibility one has in accelerating or delaying the initiation of a given scheduled maintenance activity in order to maximize the timing overlap of all plant scheduled maintenance activities.) The ARINC Research data base suggested the need for increasing some of the Fluor Engineers' estimates for maintenance activity durations and for decreasing the length of some of the allowable time windows.

Several alternative maintenance schedules were prepared using the revised maintenance durations. The first three schedules developed by ARINC Research assumed that there was no flexibility in maintenance intervals and that there was unconstrained labor and spare parts availability. The schedules were prepared by identifying the limiting maintenance actions, which would shadow all lesser events. The baseline frequency and duration data for major maintenance actions appear in Table 4-2. Only the major maintenance events are listed here, since it was determined that all other maintenance activities identified by Fluor could be shadowed by the major events.

Table 4-2

FREQUENCY AND DURATION VALUES FOR MAJOR MAINTENANCE ACTIVITIES

Activity		Maintenance Interval* (Years)		Duration (Days)	
		Fluor	ARINC Research	Fluor	ARINC Research
3.1.1	Hot Face Refractory	1.5	1.5	20.8	20.8
3.1.2	Complete Refractory	4.5	4.5	34.4	34.4
8.1.1	Steam Turbine Inspection	6	6	35	35
8.3.1	Combustor Inspection	1	1	4.4	7.6**
8.3.2	Hot-Gas-Path Inspection	3	3	10	26.3**
8.3.3	CT Major Overhaul	6	6	19	45.8**

*Time between actions.
**Based on maintenance coverage of 6 days per week, 10 hours per day.

The maintenance plan derived using the criteria in Table 4-2 is shown as "Maintenance Schedule 1" in Table 4-3. Upon examination of this schedule, it appears that the maintenance duration might be improved by synchronizing the gasifier refractory maintenance with the combustion turbine maintenance. Because the combustion turbine intervals cannot be extended, it would be necessary to decrease the gasifier intervals from 1.5 years to 1 year. To synchronize the schedule further, the steam turbine major overhaul and the combustion turbine major overhaul intervals were reduced from 6 years to 5 years. Table 4-4 presents the results of the schedule alterations. The

Table 4-3

MAINTENANCE SCHEDULE 1
(ASSUMING FIXED MAINTENANCE INTERVALS,
UNCONSTRAINED PARTS AND LABOR)

Year	Activities		Duration (Days)
1	8.3.1	CT Inspection	7.6
2	3.1.1	Hot Face Replacement	20.8
	8.3.1	CT Inspection	7.6
3	3.1.1	Hot Face Replacement	*
	8.3.2	Hot-Gas-Path Inspection	26.3
4	8.3.1	CT Inspection	7.6
5	3.1.2	Complete Refractory Replacement	34.4
	8.3.1	CT Inspection	7.6
6	3.1.1	Hot Face Replacement	*
	8.3.3	Major CT Overhaul	45.8
	8.1.1	Steam Turbine Overhaul	*
7	8.3.1	CT Inspection	7.6
8	3.1.1	Hot Face Replacement	20.8
	8.3.1	CT Inspection	7.6
9	3.1.2	Complete Refractory Replacement	34.4
	8.3.2	Hot-Gas-Path Inspection	*
10	8.3.1	CT Inspection	7.6
Total			235.7**

*Indicates shadowed maintenance.
**23.6 days/year or 6.5-percent scheduled outage rate.

10-year outage time increases from 236 days for Maintenance Schedule 1 to 269 days for Maintenance Schedule 2. Therefore, there is no incentive to synchronize combustion turbine and gasifier maintenance intervals since such synchronization requires more overall maintenance time and reduces plant availability.

Table 4-4

MAINTENANCE SCHEDULE 2:
GASIFIER MAINTENANCE AT 1-YEAR AND 5-YEAR INTERVALS,
COMBUSTION TURBINE AND STEAM TURBINE OVERHAULS
AT 5 YEARS, UNCONSTRAINED PARTS AND LABOR

Year	Activities		Duration (Days)
1	3.1.1	Hot Face Replacement	20.8
	8.3.1	CT Inspection	*
2	3.1.1	Hot Face Replacement	20.8
	8.3.1	CT Inspection	*
3	3.1.1	Hot Face Replacement	*
	8.3.2	Hot-Gas-Path Inspection	26.3
4	3.3.1	Hot Face Replacement	20.8
	8.3.1	CT Inspection	*
5	3.1.2	Complete Refractory Replacement	*
	8.3.3	Major CT Overhaul	45.8
	8.1.1	ST Overhaul	*
6	3.1.1	Hot Face Replacement	20.8
	8.3.1	CT Inspection	*
7	3.1.1	Hot Face Replacement	20.8
	8.3.1	CT Inspection	*
8	3.1.1	Hot Face Replacement	*
	8.3.2	Hot-Gas-Path Inspection	26.3
9	3.1.1	Hot Face Replacement	20.8
	8.3.1	CT Inspection	*
10	3.1.2	Complete Refractory Replacement	*
	8.3.3	Major CT Overhaul	45.8
	8.1.1	ST Overhaul	*
	Total		269.0**

*Indicates shadowed maintenance.
**26.9 days/year or 7.4-percent scheduled outage rate.

Another possibility would be to delay hot face refractory replacements so that they are performed every 2 years and only "repaired" annually. Table 4-5 identifies the effect this change would have. The 10-year outage time in this case decreases to about 204 days.

Table 4-5

MAINTENANCE SCHEDULE 3
(ASSUMING HOT FACE REFRACTORY REPLACEMENT AT
2-YEAR INTERVALS, COMPLETE REFRACTORY REPLACEMENT AT
6-YEAR INTERVALS, UNCONSTRAINED PARTS AND LABOR)

Year	Activities		Duration (Days)
1	8.3.1	CT Inspection	7.6
2	3.1.1	Hot Face Replacement	20.8
	8.3.1	CT Inspection	*
3	8.3.2	Hot-Gas-Path Inspection	26.3
4	3.1.1	Hot Face Replacement	20.8
	8.3.1	CT Inspection	*
5	8.3.1	CT Inspection	7.6
6	3.1.2	Complete Refractory Replacement	*
	8.3.3	Major CT Overhaul	45.8
	8.1.1	ST Overhaul	*
7	8.3.1	CT Inspection	7.6
8	3.1.1	Hot Face Replacement	20.8
	8.3.1	CT Inspection	*
9	8.3.2	Hot-Gas-Path Inspection	26.3
10	3.1.1	Hot Face Replacement	20.8
	8.3.1	CT Inspection	*
Total			204.4**

*Indicates shadowed maintenance.
**20.4 days/year or 5.6-percent scheduled outage rate.
Note: A full, 12-year cycle would yield an outage rate of 21.5 days/year.

This third scheduled maintenance plan yielded the minimum scheduled outage duration that would average 21.5 days per year, assuming unconstrained parts and labor. The 21.5 days per year was based on a 12-year maintenance cycle. For a 10-year cycle, the average downtime is 20.4 days per year. Inherent in this scheduled maintenance plan is the assumption that the gasifier refractory replacements can be deferred somewhat relative to the baseline maintenance requirement estimates appearing in Table 4-2.

Throughout the above discussion of scheduled maintenance plans, the underlying assumption has been that all maintenance intervals for each activity are fixed. If, on the other hand, some flexibility in the length of these intervals is allowed, then greater overlap among activities can be achieved.

The Fluor Engineers, Inc. scheduled maintenance plan yielded an estimate of 171 total days for outages during the 10-year plan period (or 4.7-percent scheduled outage rate). This estimate is lower than those developed here by ARINC Research in part because of Fluor's more liberal use of maintenance time windows. A second factor contributing to the lower Fluor result is their lower repair time estimates for certain maintenance activities in the power block. As already indicated, the Fluor estimates were used as the Scheduled Outage Rate in the analyses reported in Section 3.

STAGGERED MAINTENANCE PLANS

The assumption of unconstrained parts and labor made in previous schedules may not be reasonable, especially with regard to combustion turbine spare parts. A spare turbine rotor and hot-gas-path stationary components would cost more than $5,000,000 per unit, with a total of $15,000,000 in combustion turbine spares for a three-unit site. Utility practice has been to maintain one set of spares and stagger the scheduled maintenance to make optimal use of the spares. The benefit of that practice to the utility system is that full plant outages would be avoided.

A more realistic approach to scheduled maintenance for the IGCC plant would be a staggered maintenance program, in conjunction with annual plant outages for insurance inspections. (State law or insurance requirements generally require an annual shutdown and inspection of boiler components.) Although a detailed economic analysis is not within the scope of this study, the lower spare parts costs and the reduced effect on system capacity suggests that a staggered maintenance program is economically attractive.

A staggered maintenance plan was prepared to determine the effect on scheduled outage rate. There are several ways to synchronize events. The schedule that was prepared was not optimized, but the resulting downtime values can be considered as an approximation of scheduled outage days for a staggered maintenance program. The details of the plan are presented in Table 4-6 and Figure 4-3. A 6-year schedule was used as being reasonably representative of the full, 18-year cycle.

During the first year of the staggered maintenance plan presented in Table 4-6, all three combustion turbines were inspected with a 7-day insurance inspection occurring during the last combustion turbine inspection. The second year of the maintenance plan will include all four hot face replacements during the middle of the year, followed by three combustion turbine inspections and the annual insurance inspection at the end of the year. Toward the end of the third year of the maintenance plan, three hot-gas-path inspections will be performed, along with the hot face replacements and the annual insurance inspection. The fourth hot face replacement will extend 4.3 days into the fourth year of the maintenance plan. Also in year 4, three combustion turbine inspections and the annual insurance inspection will be completed. The fifth year of the maintenance plan will include the insurance inspection, combustion turbine inspections, and complete refractory rebrickings. The last year of the maintenance plan, year 6, will consist of overhauls for the steam and combustion turbines.

The staggered maintenance plan would require 81.3 days per year of reduced plant output; full plant outage days per year would be 7 days per year for the first 5 years and 35 days in year 6. The equivalent full plant outage rate would be 32.3 days per year (8.8%). It was concluded that a staggered maintenance program would result in the equivalent of approximately 8.7 additional days of lost production per year over and above the scheduled outage time associated with Maintenance Schedule 1.

This amounts to a loss of 125,000 megawatt hours for a 600 MW unit. These are not insignificant losses, but the costs of additional spares and unconstrained labor are also not insignificant, and should therefore be factored into the analysis before any maintenance plan is adopted.

Table 4-6

STAGGERED MAINTENANCE PLAN

Year	Maintenance Actions	Plant Derate (Percent)	Duration (Days Each)	Equivalent Full Plant Outage (Days)
1	Annual Insurance Inspection	100	7.0	
	1 Combustion Turbine Inspection Extension	33	0.6	
	2 Combustion Turbine Inspections	33	7.6	12.2*
2	Annual Insurance Inspection	100	7.0	
	1 Combustion Turbine Inspection Extension	33	0.6	
	2 Combustion Turbine Inspections and 1 Hot Face Replacement	33	7.6	
	1 Hot Face Replacement Extension	25	18.8	
	2 Hot Face Replacements	25	20.8	27.3
3	Annual Insurance Inspection	100	7.0	
	1 Hot Gas Path Inspection Extension and 1 Hot Face Replacement Extension	33	19.3	
	2 Hot Gas Path Inspections and 2 Hot Face Replacements	33	26.3	30.7
4	Annual Insurance Inspection	100	7.0	
	1 Combustion Turbine Inspection Extension	33	0.6	
	2 Combustion Turbine Inspections	33	7.6	
	1 Hot Face Replacement Extension	25	4.3	13.3
5	Annual Insurance Inspection	100	7.0	
	1 Combustion Turbine Inspection Extension	33	0.6	
	2 Combustion Turbine Inspections	33	7.6	
	1 Complete Refractory Replacement Extension	25	11.6	
	3 Complete Refractory Replacements	25	34.4	40.9
6	Steam Turbine Overhaul	100	35.0	
	1 Combustion Turbine Overhaul Extension	33	11.8	
	2 Combustion Turbine Overhauls	33	45.8	69.1
				193.5

6-year total 193.5 equivalent full outage days
Average per year 32.3 days/year
Scheduled outage rate 8.8 percent

*Calculated as follows: [(1.00)(7.0 days) + (0.33)(0.6 days) + (2)(0.33)(7.6 days)] = 12.2 days.

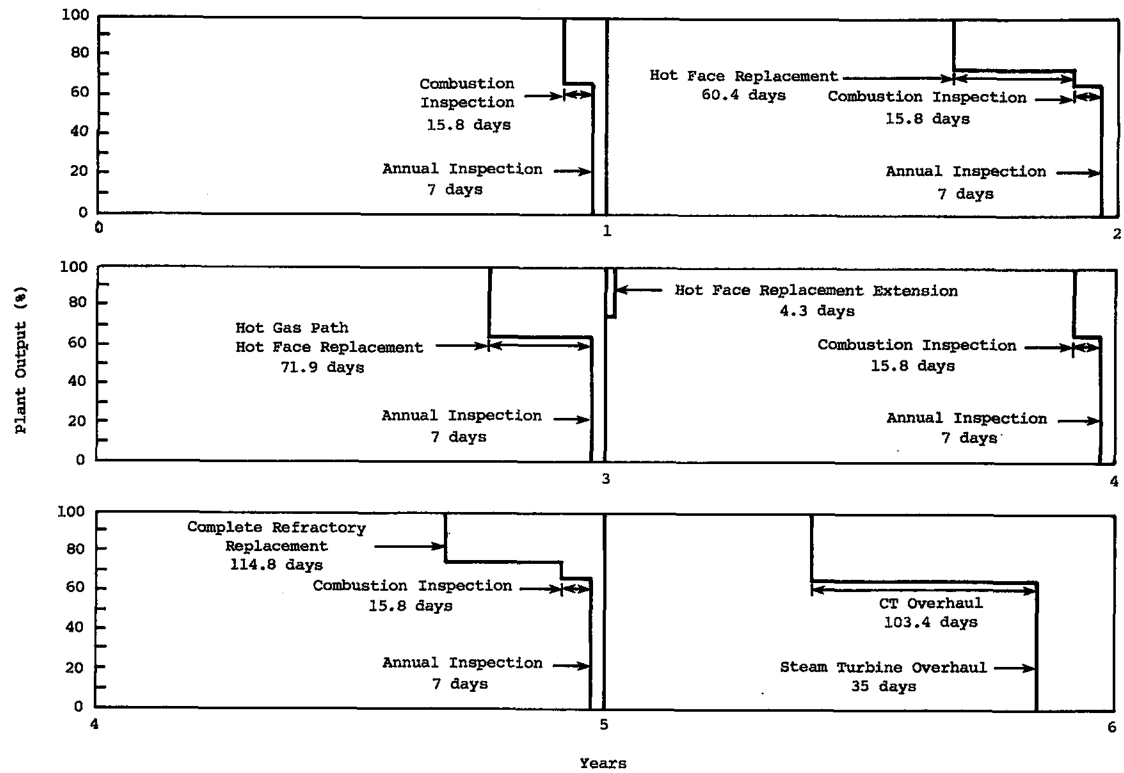


Figure 4-3. Staggered Maintenance Plan

ANALYSIS OF LIMITED SYNCHRONIZATION OF SCHEDULED MAINTENANCE ACTIVITIES WITH PLANT FORCED OUTAGES

Another method that can be used to reduce scheduled maintenance downtime takes advantage of unexpected forced outages of a plant by performing scheduled maintenance activities during repair of failures that are forcing the outage.

An analytical procedure was developed for assessing the reductions in scheduled outage days that can be expected when certain assumptions are made. The analytical procedure, presented in Appendix C, requires that a "window of opportunity" be established for each scheduled maintenance activity. This window is defined as a time interval around the normal initiation time for each scheduled maintenance activity during which, if a forced outage occurs, the scheduled maintenance would begin.

To illustrate the reductions in scheduled maintenance downtime that are achievable, the methodology was applied to scheduled maintenance plans 1 and 3. The results of the analysis are presented in Tables 4-7 and 4-8. The tables also show the time windows as described above and the downtime for each maintenance action in the schedule. Table 4-9 summarizes the results for each maintenance plan and compares the unaffected plan with the plan taking forced outages into consideration.

Through the consideration of forced outages, any possible overlaps between scheduled maintenance activities and full forced outages can be used to minimize the overall plant outage time. In the case of the baseline maintenance plan (Schedule 1), the total outage time over the 10-year study period can be reduced by 16.8 days when forced and scheduled outages are overlapped or synchronized. This translates into a 1.68-day/year savings in plant outages.

While not examined in this study, the overlapping of partial plant outages with a staggered maintenance plan represents an alternative method for synchronizing maintenance.

The windows not only allow for a synchronization of scheduled outages with forced outages, but they can also allow for improved scheduled maintenance plans. For example, using these windows and thus allowing greater flexibility in the scheduling of maintenance, a more optimum plan for Maintenance Schedule 1 can be devised. Specifically, in the second, fifth, and eighth year of Schedule 1, use of the maintenance time windows would allow for a shadowing of the combustion turbine inspections under the longer maintenance activities occurring in each of these years. As a result, the actual 10-year scheduled maintenance requirements can be reduced by 22.8 days, to a total of 212.9 days (5.8-percent outage rate) through utilization of these maintenance time windows.

CONCLUSION

In the progress of ARINC Research work, four factors were identified as the key assumptions affecting a scheduled maintenance plan for IGCC plants. These factors were:

- The assumed length of time required to accomplish each scheduled maintenance activity. A key factor in this determination is the assumption of single- versus double-shift scheduling of maintenance labor.
- The assumed existence or absence of labor and/or spare parts limitations. The existence of such limitations could lead to the need for performing scheduled maintenance in a more time-consuming, staggered fashion.

Table 4-7

MAINTENANCE SCHEDULE 1 AFTER ACCOUNTING FOR SYNCHRONIZATION WITH FORCED OUTAGES (ASSUMING FIXED MAINTENANCE INTERVALS, UNCONSTRAINED PARTS AND LABOR)

			Without Synchronization		With Synchronization
Year	Activities		Duration (Days)	Window Length (Days)	Adjusted Duration (Days)
1	8.3.1	CT Inspection	7.6	± 90	6.4
2	3.1.1	Hot Face Replacement	20.8	± 180	19.4
	8.3.1	CT Inspection	7.6	± 90	6.4
3	3.1.1	Hot Face Replacement	*		
	8.3.2	Hot-Gas-Path Inspection	26.3	± 180	24.9
4	8.3.1	CT Inspection	7.6	± 90	6.4
5	3.1.2	Complete Refractory Replacement	34.4	± 90	33.0
	8.3.1	CT Inspection	7.6	± 90	6.4
6	3.1.1	Hot Face Replacement	*		
	8.3.3	Major CT Overhaul	45.8	± 365	44.4
	8.1.1	Steam Turbine Overhaul	*		
7	8.3.1	CT Inspection	7.6	± 90	6.4
8	3.1.1	Hot Face Replacement	20.8	± 180	19.4
	8.3.1	CT Inspection	7.6	± 90	6.4
9	3.1.2	Complete Refractory Replacement	34.4	± 90	33.0
	8.3.2	Hot-Gas-Path Inspection	*		
10	8.3.1	CT Inspection	7.6	± 90	6.4
	Total		235.7		218.9
	Scheduled outage rate		6.46%		6.00%

*Indicates shadowed maintenance.

Table 4-8

MAINTENANCE SCHEDULE 3 AFTER ACCOUNTING FOR SYNCHRONIZATION WITH FORCED OUTAGES (ASSUMING HOT FACE REFRACTORY REPLACEMENT AT 2-YEAR INTERVALS, COMPLETE REFRACTORY REPLACEMENT AT 6-YEAR INTERVALS, UNCONSTRAINED PARTS AND LABOR)

			Without Synchronization		With Synchronization
Year	Activities		Duration (Days)	Window Length (Days)	Adjusted Duration (Days)
1	8.3.1	CT Inspection	7.6	± 90	6.4
2	3.1.1	Hot Face Replacement	20.8	± 180	19.4
	8.3.1	CT Inspection	*		
3	8.3.2	Hot-Gas-Path Inspection	26.3	± 180	24.9
4	3.1.1	Hot Face Replacement	20.8	± 180	19.4
	8.3.1	CT Inspection	*		
5	8.3.1	CT Inspection	7.6	± 90	6.4
6	3.1.2	Complete Refractory Replacement	*		
	8.3.3	Major CT Overhaul	45.8	± 365	44.4
	8.1.1	ST Overhaul	*		
7	8.3.1	CT Inspection	7.6	± 90	6.4
8	3.1.1	Hot Face Replacement	20.8	± 180	19.4
	8.3.1	CT Inspection	*		
9	8.3.2	Hot-Gas-Path Inspection	26.3	± 180	24.9
10	3.1.1	Hot Face Replacement	20.8	± 180	19.4
	8.3.1	CT Inspection	*		
Total			204.4		191.0
Scheduled outage rate			5.60%		5.23%

*Indicates shadowed maintenance.

Table 4-9

SUMMARY OF RESULTS FOR MAINTENANCE SCHEDULES TAKING ADVANTAGE OF FORCED OUTAGES

Maintenance Schedule	Scheduled Outage Days Not Taking Into Account Synchronization with Forced Outages (Days)	Scheduled Outage Days Taking Into Account Synchronization with Forced Outages (Days)	Difference (Days)
Schedule 1	235.7	218.9	16.8
Schedule 3	204.4	191.0	13.4

- The assumed existence or absence of flexibility in the scheduling of equipment maintenance. If there is some flexibility to perform a certain activity within a given time window (as opposed to performing it at exact time intervals), then greater overlap among scheduled maintenance activities can be achieved.
- The assumption regarding the ability to accomplish some scheduled maintenance during forced outages.

A number of scheduled maintenance plans were developed. These plans differ from one another with respect to certain fundamental assumptions. The scheduled outage rate results are summarized in Table 4-10.

As can be seen from Table 4-10, the scheduled outage rate is quite sensitive to the analysis assumptions. It can vary from 4.7 percent to 8.8 percent. Taking as an example Plans A and B, a change in two assumptions yields a 1.8-percentage point change in the estimated scheduled outage rate. These two plans differ in their estimates of the maintenance activity durations in the combined-cycle section of the IGCC. The ARINC Research estimates of such activities are typically more than twice as great as the Fluor/G.E. estimate in Plan A. These plans also differ in that the ARINC Research plan assumes there is no flexibility in scheduling maintenance activities, whereas the Fluor plan allows the maintenance to be accelerated or delayed somewhat in order to maximize overlap among closely occurring maintenance activities. Of the 1.8-percentage point difference between the scheduled outage rate estimates in these two plans, 1.2 percent is attributable to the differences in the estimates of scheduled maintenance activity durations.

Table 4-10

SCHEDULED MAINTENANCE PLANS

Assumptions	Plan A (Ref. Page B-1)	Plan B (Ref. Table 4-3)	Plan C (Ref. Table 4-6)	Plan D (Ref. Page 4-16)	Plan E (Ref. Table 4-7)
Relative Maintenance Activity Durations	Short	Long	Long	Long	Long
Labor or Spare Parts Limitations	No	No	Yes	No	No
Flexibility in Scheduling Maintenance	Yes	No	No	Yes	No
Any Overlap Between Forced and Scheduled Outages	No	No	No	No	Yes
Source of Estimate	Fluor	ARINC	ARINC	ARINC	ARINC
Scheduled Outage Rate, Percent	4.7	6.5	8.8	5.8	6.0

Section 5

FINDINGS AND CONCLUSIONS

The IGCC plant addressed in this analysis employs many modular design features that give the plant high equivalent availability through redundancy. The study focused on evaluating and quantifying the expected changes in unit capability, equivalent availability, and heat rate associated with various design alternatives.

The findings of the baseline case studies are as follows:

- The Baseline IGCC design using four gasifiers with 11.2-percent spare gasification capacity and three combustion turbine/HRSGs sets will have an expected equivalent availability of 86.18 percent and an average heat rate of 9,002 Btu/kWh.

- The Baseline with Supplemental Firing design using four gasifiers with the 11.2-percent spare gasification capacity being used to produce supplemental steam and with three combustion turbine HRSG sets will have an expected equivalent availability of 85.64 percent and an average heat rate of 9,147 Btu/kWh.

- The Baseline with Natural Gas Backup design using four gasifiers and three combustion turbine/HRSG sets with supplemental natural gas backup will have an expected equivalent availability of 91.53 percent with an average heat rate of 8,981 Btu/kWh and a coal-to-natural gas fuel mixture of 23:1.

The findings of the sensitivity studies are as follows:

- With a 25-percent spare gasification capacity, the Baseline IGCC and the Baseline with Natural Gas Backup models are expected to have equivalent availabilities of 87.65 percent and 91.67 percent, respectively.

- A sensitivity study was performed on the Baseline IGCC configuration. In this sensitivity analysis, the IGCC was designed such that the gasification plant was sized to fully load the combustion turbines at the high ambient temperature of 88°F (as compared with the baseline case design point of 20°F). When operated at 59°F, this 88°F-designed plant will have no spare gasification capacity, but it will have 11.5-percent spare combustion turbine and HRSG capacity. The equivalent availability for this plant operating at 59°F was 85.96 percent.

- The plant equivalent availability was sensitive to changes in storage-point capacities. Storage point 5 (oxygen plant) had the greatest impact on plant availability.

- The uncertainty in reliability and maintainability data for the Texaco-based gasification-through-gas-scrubbing section of the plant has been quantified by using reliability and maintainability data estimates supplied by Texaco, Inc. for pessimistic, optimistic, and baseline scenarios. The equivalent availabilities for the pessimistic and optimistic cases were 82.38 percent and 87.03 percent, respectively. The 90-percent confidence interval was ± 0.01 percent from the Baseline Case equivalent forced outage rate (EFOR) of 9.57 percent.

- If for regulatory reasons the plant is not allowed to flare tail gas, equivalent availability will drop from 86.18 percent, for the Baseline Case, to 85.03 percent.

The availability analyses presented in this report quantify the availability impacts of several IGCC plant design options. In addition, the heat-rate analyses give an indication of the average efficiency of each baseline case design. Design options cannot be evaluated on an availability basis alone. The performance data presented in this report, combined with site-specific economic variables, can be used to develop cost-to-benefit ratios for each design option.

ARINC Research employed the combined-cycle data from the EPRI Reliability Assessment System (ERAS), together with gasification estimates from Fluor Engineers, Inc. and Texaco, Inc., in the process of developing the scheduled maintenance plan. An assumption was made that there was no constraint in terms of either the spare parts or labor required to accomplish the maintenance activities. When the base set of maintenance requirement assumptions is used for all plant components, including the gasifier rebricking requirements, and when certain flexibility is assumed in the scheduling of maintenance activities, the 10-year scheduled maintenance requirements amount to 235.7 days, or 23.6 days/year. This translates into a scheduled outage rate of 6.5 percent. A reduction in this scheduled maintenance requirement could be accomplished by taking advantage of some unexpected plant forced outages in order to perform certain pending scheduled maintenance activities. In this manner, the overall forced plus scheduled outage times can be minimized.

The assumption of unconstrained parts and labor in the above-described analysis is not judged to be reasonable for a utility application. Limited availability of spare parts, supervisory personnel, and skilled labor would result in extended outages if all maintenance were performed concurrently. For this reason, a staggered maintenance approach is an attractive alternative. A staggered maintenance program would reduce the spare parts inventory and the labor requirements and would also reduce the duration of full plant outages. The cost of implementing staggered maintenance is an increase in the frequency and duration of deratings, with the overall effect being lower equivalent availability. The scheduled outage rate for a staggered maintenance plan was estimated to be 8.8 percent, or 32.3 equivalent full outage days per year. The full plant outage rate would be reduced to 3.2 percent, or 11.7 days per year, with the remainder of the scheduled outages being deratings.

Appendix A

UNIRAM ANALYSIS METHODOLOGY AND RUN RESULTS

OVERVIEW OF THE UNIRAM METHODOLOGY

The UNIRAM availability analysis methodology was developed by ARINC Research Corporation for the Electric Power Research Institute (EPRI) for use in evaluating alternative designs of advanced power systems, such as the IGCC plant described in this report. The UNIRAM software was documented and subsequently made available to EPRI member utilities. UNIRAM has been used to analyze fossil, nuclear, and cogeneration power systems. A brief overview of the UNIRAM methodology is provided in this appendix. More detailed information is available in the User's Guide for the UNIRAM Availability Assessment Methodology, EPRI report AP-3305-CCM, and in Reliability and Availability Analyses of Coal Fired Units: Validation of a Predictive Methodology, EPRI report AP-2938.

UNIRAM MODELING METHODOLOGY

To perform an availability analysis, complex power systems are normally modeled by the use of analytical methods and suitable computer codes. The UNIRAM code is an analytical method using probability-theory fault tree logic. UNIRAM evaluates all operating states of the unit and determines the probability of operation at each output state. The state output capabilities and probabilities are combined to develop equivalent availability predictions. UNIRAM calculates the system-level availability and equivalent availability as a function of the configuration of the plant and the capacity, reliability, and maintainability of the plant's components. Critical terms used in the methodology are defined as follows:

- Component - Any system element for which available data cannot be broken down for assignment to lower-level elements.
- Basic Subsystem - An aggregation of components whose failures have identical impacts on plant operation. A basic subsystem can have only two operating states -- full capacity or zero capacity -- and it connects with other subsystems only at its end points.
- Fault Tree - A graphic portrayal of the structure of a basic subsystem that indicates which combinations of component failures within the basic subsystem would make the subsystem unavailable.

- Nested Subsystem - An aggregation of basic or other nested subsystems in simple series or parallel configurations.
- Availability Block Diagram - An aggregation of basic and nested subsystems to the system level that represents the configuration of the plant.

The following basic assumptions are made in modeling the plant:

- Components fail and are repaired independently of each other.
- Component failure and restoration rates are constant over the period of time considered.
- Component degradation has a negligible effect on unit output for a given run.
- The inventory of spares is replenished as spares are used.

Situations that do not conform to these assumptions can be evaluated with special modeling methods or analyses. System interdependencies can be represented directly or indirectly. For example, if a transformer failure results in a motor failure (or loss of power), which in turn results in a unit outage, it is not necessary (although it is possible) to identify the interdependencies. If the failure of the transformer is known to result in a unit outage until the transformer is replaced or repaired, the transformer can be included in a fault tree, with its failure shown as causing a unit outage. It is not necessary to model the details of the outage event precisely. Thus the transformer appears one time, and it need not be represented in all the subsystems to which it feeds power.

NONLINEAR OUTPUT STATES

System interdependencies can be modeled with UNIRAM by integrating manual calculations with the UNIRAM software. Several system interdependencies exist in the IGCC plant that cannot be modeled by using UNIRAM alone. For example, in Baseline IGCC, a HRSG failure causes plant output to decrease from 598 MW to 514 MW. If a gasifier fails, plant output decreases to 491 MW. However, the simultaneous failure of a HRSG and a gasifier causes plant output to decrease to 424 MW. This operating condition cannot be modeled by using UNIRAM. To model this condition with the UNIRAM software, one would have to be able to override both HRSG and gasifier parallel nested subsystems, and UNIRAM is unable to do this in its present form.

A special procedure was developed to model system interdependencies, such as the condition described above, for the IGCC plant. To illustrate the methodology, consider the system shown in Figure A-1. The state probabilities of each parallel subsystem and the total system are shown in Table A-1.

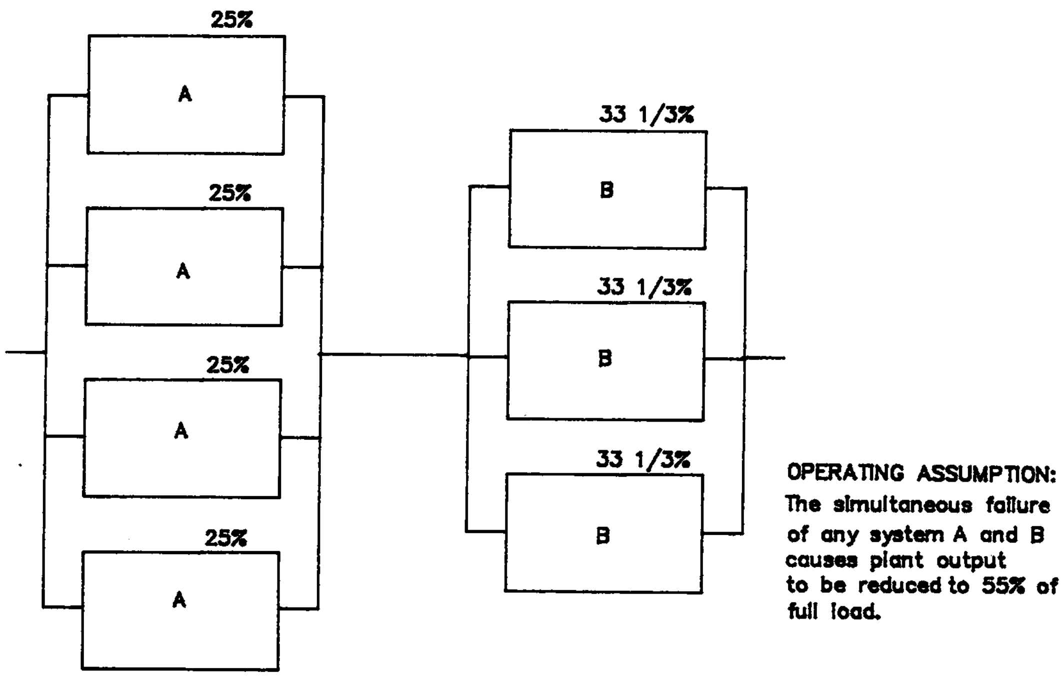


Figure A-1. Sample System

Taking as an example the 66.6-percent total system output state, the UNIRAM-calculated probability of arriving at this given output level is determined as follows:

Probability of arriving at a 66.6% system output level

OR

P(66.6% system output level) = P(one B subsystem failure)
x P(less than two A subsystem failures)
= (0.0286)(0.9533 + 0.0374)
= 0.0283

Table A-1

STATE PROBABILITIES FOR THE SAMPLE SYSTEM

System	Output State (Percent)	Probability*
Parallel System A	100	0.9533
	75	0.0374
	50	0.0093
	25	0.0000
	0	0.0000
Parallel System B	100	0.9642
	66.6	0.0286
	33.3	0.0072
	0	0.0000
Total System	100	0.9192
	75	0.0361
	66.6	0.0283
	50	0.0092
	33.3	0.0072
	25	0.0000
	0	0.0000

*Probabilities were created for example purposes only and do not represent any existing subsystems.

This value of 0.0283 can be found under the total system output state in Table A-1. If instead the total system output when there is a simultaneous failure of subsystem A and B is 55 percent, not 66.6 percent, then the probability of this "nonlinear" 55-percent output state would be:

P(simultaneous failure of A and B) = P(of 1 A subsystem failure)
x P(of 1 B subsystem failure)*
= (0.0374)0.0286
= 0.0011

*All other state probabilities held constant for the 66-percent capacity output state.

Thus, Table A-1 would be modified such that the probability of a 66.6-percent output level is reduced by the probability of this nonlinear (55 percent) output state.

$$
\begin{aligned}
P(66.6\%\ \text{output}) &= (0.0283) - (0.0011) \\
&= 0.0272
\end{aligned}
$$

A modified output state table can now be developed as shown in Table A-2.

Table A-2

MODIFIED OUTPUT STATE TABLE
INCLUDING OPERATING ASSUMPTIONS

System	Output State (Percent)	Probability
Total System	100	0.9192
	75	0.0361
	66.6	0.0272*
	55	0.0011*
	50	0.0092
	33.3	0.0072
	25	0.0000
	0	0.0000

*States affected by operating assumption.

This same methodology was applied to all cases of nonlinear simultaneous failures in the IGCC design. Future enhancements to the UNIRAM software could automate this analysis.

MODEL DEVELOPMENT

A model is prepared by defining the basic and nested subsystems within the plant and preparing fault trees for each basic subsystem. The fault trees show the components necessary for subsystem operation. The fault trees employ OR gates ( ) and AND gates ( ) to define the way in which component failures can affect the subsystem. An OR gate indicates that failure of any component block below the OR gate will cause a failure of the block directly above the OR gate. In addition to the conventional OR gate, UNIRAM employs qualified OR gates. A qualified OR gate defines how many blocks out of the total number of blocks below the qualified OR gate must fail before the upper block fails. An AND gate indicates that all of the components under the gate must fail to cause a failure of the block above the gate.

An important feature of UNIRAM is that events can be modeled as well as components. If transient operation problems are not clearly attributable to a single component or subsystem, the event itself can be entered as a subsystem or component if the mean time between occurrences and mean duration of the event can be determined. Outside events, such as lightning strikes or earthquakes, can be incorporated into the model in a similar fashion. These techniques are useful for incorporating incidents such as interruption of fuel supply or loss of system interconnections.

The basic subsystems are organized into the availability block diagram (ABD). The specific data on plant configuration and component reliability and maintainability are contained in the data input file. This file must be created before the UNIRAM software can be used. The data input file is a code that identifies the topology of components within the system, their configuration, and their reliability and maintainability characteristics. Component reliability is expressed as mean time between failures (MTBF), and component maintainability is expressed as mean down-time (MDT).

UNIRAM ANALYSIS METHODOLOGY

The UNIRAM methodology uses conventional reliability theory to analyze plant configurations. The software defines all possible plant operating states and determines system-level availability probabilistically. To illustrate this methodology, the simple series-parallel system in Figure A-2 will be evaluated. Components A, B, and C in this figure have capacities of 100 percent.

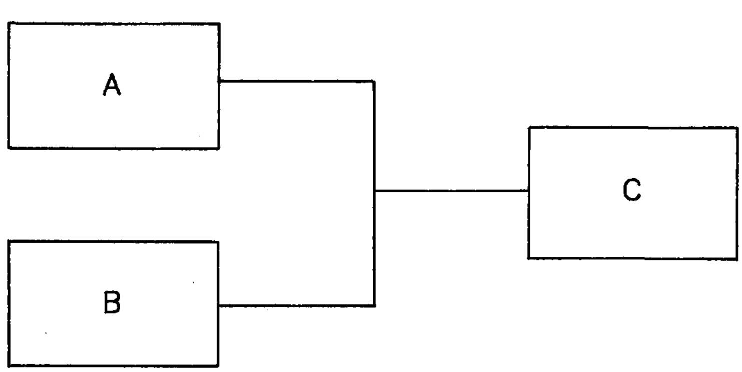


Figure A-2. Example of Availability Block Diagram

For the system to deliver 100-percent output, either A and C or B and C must be available. Reliability theory states that the probability of full-up operation is given by:

$$[P(A\text{ up}, B\text{ up}) + P(A\text{ up}, B\text{ down}) + P(A\text{ down}, B\text{ up})]\ P(C\text{ up})$$

The probability that A, B, or C will be available is calculated from the point estimate of availability (A):

$$A = \frac{MTBF}{MTBF+MDT}$$

Assuming availabilities of A = 0.9, B = 0.9, C = 0.95, the system availability becomes:

$$[(0.9)(0.9) + (0.9)(0.1) + (0.1)(0.9)] \times 0.95 = 0.9405$$

The UNIRAM software applies the appropriate equations to the configurations specified by the analyst. The MTBF and MDT data provided as program inputs are used to determine component availabilities and, eventually, plant state availabilities. The software is necessary because the complexity of power system models would require extensive manual calculations. It should be noted that the UNIRAM output results can be verified by calculation, especially at the subsystem level. The UNIRAM software performs these calculations in a minute fraction of the time required by manual means and allows analyses with immediate results.

There are nine execution options available in UNIRAM, which are listed and briefly described in Table A-3. The options are summarized in the following subsections. Additional detailed information is provided in the UNIRAM User's Guide.

BASELINE RUN

The baseline run is the fundamental execution option of the software. It provides reliability and maintainability data at the plant (or system) level, including:

- Effectiveness (E). The percentage of the unit's desired gross maximum generation that was available.
- Forced outage rate (FOR). The percentage of time the unit's service was desired but was unavailable because of full forced outages.

- Equivalent forced outage rate (EFOR). The percentage of the unit's maximum generation that was desired but was unavailable because of full forced outages and deratings.

- Equivalent availability (EA). The percentage of the unit's maximum energy production that was available.

- Availability (A). The percentage of time the unit could produce power without regard to capability.

Table A-3

UNIRAM EXECUTION OPTIONS

Option	Code	Summary of Results	Additional Information Required
Baseline	BL	RAM measures for unit and subsystems	None
Component Ranking	CR	Rank-ordering of components according to sensitivity or criticality	Choice of ranking criterion; number of components to be output, starting at top of list
Component Data Changes	CD	Baseline results as altered by temporary changes to selected component MTBF/MTTR values	For each selected component: • Subsystem name • Component name • New MTBF (temporary) • New MTTR (temporary)
Baseline with Load Curve	BC	Percentage of time demand could be met or exceeded; annual number of makeup megawatthours required	Load-curve coordinates
Subsystem Sensitivity	SS	Unit EFOR as each basic subsystem's availability factor is varied from 0.8 to 1.0	None
Statistical Uncertainty Analysis	ST	Means and standard deviations of unit-level RAM measures	Number of samples (repeated executions), random number generator seed
Time-Variant Availability	TA	Rate of decline of unit effectiveness, assuming initially at 100 percent	Number of days to be considered
Time-Variant Reliability	TR	Rate of decline of unit effectiveness, assuming initially at 100 percent, with no restoration of failed equipment; also, probability of maintaining given output level for a given time	Number of days or threshold effectiveness level
Component Sparing	CS	Baseline results as altered by temporary component sparing	Component to be spared

Appendix B

FLUOR MAINTENANCE PLAN

This appendix reproduces the Fluor Engineer and Constructors' maintenance plan from EPRI report AP-3486, Cost and Performance for Commercial Applications of Texaco-Based Gasification-Combined-Cycle Plants, April 1984.

MAJOR MAINTENANCE ACTIVITIES

Activity	Description	Duration (Days)	Frequency (Years)
1.0	COAL RECEIVING, GRINDING, AND SLURRY PREPARATION		
1.1	Major Equipment Items - Unloading Hoppers, Vibrating Feeders, Tripper, Conveyors, Magnetic Separation, and Double Boom Stacker		
1.1.1	Follow normal lubrication schedules recommended by the manufacturer	Short	Regular
1.2	All Conveyors		
1.2.1	Replace "T" frame motors and coupling media	1	2
1.2.2	Replace drive chain	1	2
1.3	Bucket Wheel Reclaimer		
1.3.1	Replace/reweld all buckets as required	1	1
1.4	Wet Pulverizers		
1.4.1	Replace worn rollers/grinders	1	0.5
1.4.2	Replace screen decks (spare bin, feeder, and pulverizer capacity is included in the design)	1	2
2.0	OXIDANT FEED		
2.1	Air Compressor		
2.1.1	Inspect bearings, couplings, and labyrinth seals	2.5	1-2
2.1.2	Inspect lube oil system pump seals, bearings, and couplings	2	1-2
2.1.3	Change lube oil filters as required by differential pressure indication (no downtime with dual filters)	0.5	1
2.1.4	Inspect, clean, and balance impellers/rotor	5.5	6
2.1.5	Clean intercoolers	3.5	1-2
2.2	Oxygen Compressor		
2.2.1	Inspect bearings, couplings, gears, and labyrinth seals	3	1-2

MAJOR MAINTENANCE ACTIVITIES (continued)

Activity	Description	Duration (Days)	Frequency (Years)
2.2.2	Inspect lube oil system pump seals, bearings, and couplings	2	1-2
2.2.3	Change lube oil filters as required by differential pressure indication (no downtime with dual filters)	0.5	1
2.2.4	Inspect impellers and balance rotor, if necessary	5	5
2.2.5	Clean intercoolers on the waterside (shell)	4	4
2.3	Electrical Instrumentation		
2.3.1	Inspect main drive motor bearings and windings, conduct megger and high pot tests	2.5	1-2
2.3.2	Perform electrical relay/contractor/ instrumentation inspections	2.5	1-2
2.4	Cold Box		
2.4.1	Safety defrost and deriming, heat exchanger inspection and cleaning (interval can be extended based on hydrocarbon contamination experience)	4.5	1-2
2.4.2	Expansion turbine - suggest complete spare plug in unit	1	1-2
3.0	COAL GASIFICATION AND ASH HANDLING		
3.1	Texaco Gasifier		
3.1.1	Hot-face refractory replacement	20.8	1.5
3.1.2	Complete refractory replacement	34.4	4.5
3.2	Radiant Syngas Cooler		
3.2.1	Inspect cooler panels	2	1
3.2.2	Inspect lock hooper valves and slag breaker	1	1
3.3	Convective Syngas Cooler		
3.3.1	Inspect tubes	1	1
3.4	Slurry Charge Pump		
3.4.1	Replace Diaphragms	1	1

MAJOR MAINTENANCE ACTIVITIES (continued)

Activity	Description	Duration (Days)	Frequency (Years)
3.4.2	Check valves and power train (spare charge pump capacity is included in the design)	1	0.25
3.5	Ash Dewatering System		
3.5.1	Clean all exchanger tube bundles	1	2
3.5.2	Inspect all pump bearings, seals, and couplings (all essential pumps are spared)	1	0.5-1
3.6	Gas Scrubbing Unit		
3.6.1	Inspect vessel for corrosion/erosion	1	1
4.0	<u>GAS COOLING AND FUEL GAS SATURATION</u>		
4.1	Various Heat Exchangers		
4.1.1	Clean tube bundles	1	2
4.2	Air-Cooled Exchanger		
4.2.1	Clean coils	1	1
4.2.2	Replace belts as needed (air cooler operated in summer only)	1	2
5.0	<u>ACID GAS REMOVAL</u>		
5.1	Refrigeration Unit		
5.1.1	Inspect compressor bearings, seals, couplings, gears, and lube oil system pumps	2	1
5.2	Various pumps and hydraulic turbine (all pumps are spared)		
5.2.1	Inspect bearings, seals, and couplings	1	1
5.3	Overhead Condenser (Air Cooler)		
5.3.1	Replace belts as needed	0.5	2
5.4	Plate Exchanger		
5.4.1	Clean plates and replace gaskets	2	2

MAJOR MAINTENANCE ACTIVITIES (continued)

Activity	Description	Duration (Days)	Frequency (Years)
6.0	SULFUR PLANT (100% spare unit included in design)		
6.1	Sulfur Furnace		
6.1.1	Repair/replace refractory	7	2
6.2	Sulfur Condensers		
6.2.1	Clean tubes	1	0.25
6.3	Sulfur Converters		
6.3.1	Change catalyst	2	5
6.4	Air Blower		
6.4.1	Inspect bearings, seals, couplings, gears, and lube oil system	2	1-2
6.5	Molten Sulfur Pump		
6.5.1	Inspect bearings, seals, and couplings	1	1
7.0	TAIL GAS TREATING (SCOT UNIT)		
7.1	Reducing Gas Generator		
7.1.1	Repair/replace refractory	2	2
7.2	Hydrogenation Reactor		
7.2.1	Change catalyst	2	5
7.3	Heat Exchangers		
7.3.1	Clean tube bundles	1	2
7.4	Pumps (all pumps are spared)		
7.4.1	Inspect bearings, seals, and couplings	1	1
8.0	STEAM AND POWER SYSTEMS		
8.1	Main Steam Turbine		
8.1.1	Major inspection of complete unit including electric generator, lube and seal oil systems, and excitation and control systems	35	6

MAJOR MAINTENANCE ACTIVITIES (continued)

Activity	Description	Duration (Days)	Frequency (Years)
8.2	Main Surface Condenser		
8.2.1	Clean tubes (frequency based on performance deterioration)	2	2
8.3	Gas Turbines		
8.3.1	Combustor inspection	4.4	1
8.3.2	Complete hot gas path inspection	10	3
8.3.3	Major inspection and overhaul including electric generator	19	6
8.4	Heat Recovery Steam Generators		
8.4.1	Annual inspection (or as required by local jurisdiction)	2	1
8.4.2	Clean external tube surfaces	2	1
8.4.3	Acid-clean tube and drum internals	3	6
8.4.4	Open steam drums and deaerator for visual inspection	2	1
8.5	Boiler Feedwater Pump (spared unit)		
8.5.1	Inspect bearings, seals, couplings, and lube oil system	1	1
8.5.2	Inspect steam turbine driver	1	1
8.5.3	Inspect electric motor driver	1	2
8.6	Demineralizer		
8.6.1	Change resin and check thickness of rubber-lined vessels (spare capacity is included in the design)	1	4

Table B-1

10-YEAR DOWNTIME SUMMARY

Activity Number	Annual Downtime (Days per Year) Year Number									
	1	2	3	4	5	6	7	8	9	10
2.2.4					5.0					5.0
2.4.1		4.5		4.5		4.5		4.5		4.5
3.1.1		20.8	20.8				20.8	20.8		
3.1.2					34.4					34.4
8.1.1					35.0					35.0
8.3.1	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4
8.3.2			10.0					10.0		
8.3.3					19.0					19.0
Longest Duration	4.4	20.8	20.8	4.5	35.0	4.5	20.8	20.8	4.4	35.0

Total downtime for 10 years = 171 days

Appendix C

METHODOLOGY FOR COMPUTING TOTAL EXPECTED SCHEDULED MAINTENANCE DOWNTIME WHEN SCHEDULED MAINTENANCE ACTIVITIES ARE PERMITTED DURING PERIODS OF UNEXPECTED FORCED OUTAGE

One approach to reducing the time lost to scheduled outages is to take advantage of forced outage periods by using them to perform scheduled maintenance activities. This approach is implemented by first recognizing that there is an acceptable range of times -- or window -- in which a given periodic scheduled maintenance can be performed rather than a single discrete point in time. Thus, if a given scheduled maintenance must be performed every time period, T, this approach says the action can be initiated any time from t_1 to t_2 without impairing the maintenance effectiveness (where $t_2 - t_1$ represents the stated window duration for the specific maintenance action). In this manner, when scheduled maintenance (SM) is being performed concurrent with corrective maintenance (CM) arising from a forced outage occurring within the defined window, only the SM time in excess of the CM time will be attributable to the scheduled outage. The problem is to determine the expected scheduled outage time, taking into account the possibility of concurrent actions. The approach to determining this outage time is described below.

Let:

X = the time required to perform a specific SM action. (X is a random variable and not the mean [or MDT_S] of all scheduled maintenance activities.)

Y = the forced outage duration (i.e., the time to perform the CM action). (Y is a random variable and not the MDT_C.)

Z = the time attributed to SM when it is performed concurrent with CM
$= X - Y$ for $X > Y$
$= 0$ for $X \leq Y$

W = the window length $(t_2 - t_1)$

t = the time of the forced outage

It is assumed that the SM action will not be initiated if $t < t_1$. If $t_1 \leq t < t_2$, the action will be initiated immediately with the assumption that the SM and CM activities are independent and performed in parallel. If a forced outage has not occurred by t_2 (i.e., $t > t_2$), it is assumed that the SM action is initiated at t_2 and will have duration X. Thus, the time, S, attributed to SM, considering both concurrent and non-concurrent maintenance situation, is:

$$
\begin{aligned}
S &= Z; \; t_1 \leq t < t_2 \\
&= X; \; t \geq t_2 \\
&= 0; \; t < t_1
\end{aligned}
$$

Let:

$\bar{S}$ = the expected time attributed to SM

$P_f(W)$ = the probability of a forced outage (F/O) in the interval (t_1, t_2)

The expected time attributed to SM is given by the expected SM time when there is concurrent maintenance plus the expected SM time when there is not concurrent maintenance, each weighted by their respective probabilities of occurrence. Mathematically, this is given by:

$$
\bar{S} = E(S|F/O \text{ in window}) \bullet \text{Prob } (F/O \text{ in window}) + E(S|F/O \text{ after window}) \bullet \text{Prob } (F/O \text{ after window})
$$

However, by definition:

$E(S|F/O \text{ after window}) = E(X)$ = the expected downtime for the SM action (MDT_s)

Further, since failures are assumed to be exponentially distributed:

$$
\text{Prob } (F/O \text{ in window}) = P_f(W) = 1 - e^{-W/MTBF_f}
$$

$$
\text{Prob } (F/O \text{ after window}) = 1 - P_f(W) = e^{-W/MTBF_f}
$$

where $MTBF_f$ is the mean time between forced outages.

Thus the expected time attributed to SM is:

$$
\bar{S} = E(S|F/O \text{ in window}) \; (1 - e^{-W/MTBF_f}) + MDT_s \; e^{-W/MTBF_f}
$$

The last item to be resolved is to determine the expected time attributed to SM, given a forced outage occurs in the window. The following pages describe the development of this term, and the very last equation in this appendix shows the substitution of this term into the above equation.

By definition,

$$E(S|F/O \text{ in window}) = E(Z)$$

Therefore

$$\bar{S} = E(Z)(1 - e^{-W/MTBF_f}) + MST_S\ e^{-W/MTBF_f}$$

The problem now is to find E(Z). In order to focus our calculations on the scheduled maintenance time when forced outages occur in the window (or X-Y), consider the following transformation of variables:

$$U = Y$$
$$V = X - Y$$

Each of these variables (X, Y, U, and V) can be described by a "density function." As an example, Y (the forced outage duration) can have a range of values, and the relationship between the value of Y and the frequency that Y will be that particular value is called the density function. Since X and Y are random variables, U and V will also be random variables. Moreover, the joint density function $p_{u,v}(U,V)$ is related to the joint density function of X and Y, $p_{x,y}(X,Y)$ by the following transformation theorem:

$$p_{u,v}(U,V) = p_{x,y}(X,Y)|J|$$

where |J| is the absolute value of the Jacobian, defined as the determinant of the following matrix:

$$\begin{bmatrix} \frac{\partial X}{\partial U} & \frac{\partial X}{\partial V} \\ \frac{\partial Y}{\partial U} & \frac{\partial Y}{\partial V} \end{bmatrix}$$

Rewriting the transformation as a function of (U,V)

$$Y = U$$
$$X = U + V$$

The Jacobian becomes:

$$J = \mathrm{Det}\begin{bmatrix} 1 & 1 \\ 0 & 1 \end{bmatrix} = 1$$

and the transformation becomes:

$$P_{u,v}(U,V) = P_{x,y}(U + V,\ U)$$

However, since X and Y are independent random variables (i.e., the value of CM is independent of the value of SM),

$$P_{x,y}(U + V,\ U) = p_x(U + V)\ P_y(U) = P_{u,v}(U,V)$$

The density function of the single random variable V can then be found by integrating $p_{u,v}(U,V)$ over the variable U, thus eliminating this latter variable, i.e.:

$$p_v(V) = \int_{-\infty}^{\infty} p_{u,v}(U,V)dU = \int_{-\infty}^{\infty} p_x(U + V)p_y(U)dU$$

Physically $P_v(V)$ represents the density function of V, which is the frequency of V as any particular value. For example, since V equals (X - Y), then for V = 3, $P_v(V) = P_3(3)$, which in turn represents the frequency that (X - Y) equals 3 for all values of X and Y.

The variable V can take on both positive and negative values, even though X and Y can only be positive, depending on whether the scheduled maintenance action takes more or less time than the corrective action.

Assuming X and Y are both exponentially distributed with mean downtimes of MDT_s and MDT_c, respectively, their densities are given by:

$$p_X(X) = \frac{1}{MDT_S} e^{-X/MDT_S};\ X \geq 0$$

$$= 0;\ X < 0$$

$$p_Y(Y) = \frac{1}{MDT_C} e^{-Y/MDT_C};\ Y \geq 0$$

$$= 0;\ Y < 0$$

and substituting:

$$p_X(U + V) = \frac{1}{MDT_S} e^{-(U + V)/MDT_S};\ V + U \geq 0$$

$$= 0;\ U + V < 0$$

$$p_Y(U) = \frac{1}{MDT_C} e^{-U/MDT_C};\ U \geq 0$$

$$= 0;\ U < 0$$

When $V \geq 0$, i.e., scheduled maintenance time is greater than corrective maintenance time, the integral situation for $p_v(V)$ is as shown in Figure C-1 and $p_v(V)$ is given by:

$$p_V(V) = \frac{1}{(MDT_S)(MDT_C)} \int_0^\infty e^{-(U + V)/MDT_S}\, e^{-U/MDT_C}\, dU;\ V \geq 0$$

$$= \frac{e^{-V/MDT_S}}{(MDT_S)(MDT_C)} \int_0^\infty e^{-U(MDT_S + MDT_C)/(MDT_S)(MDT_C)}\, dU;\ V \geq 0$$

$$= \frac{e^{-V/MDT_S}}{(MDT_S + MDT_C)}\ ;\ V \geq 0$$

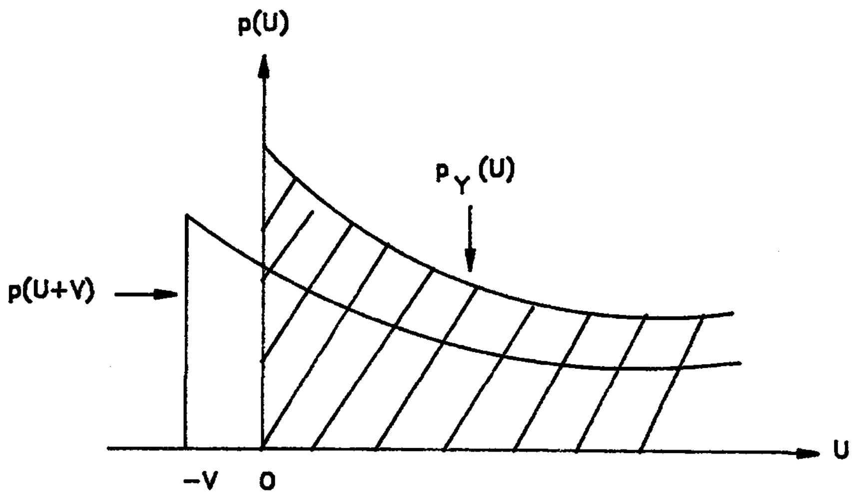


Figure C-1. Integral Geometry for $V \geq 0$

Similarly, for $V < 0$ as illustrated in Figure C-2,

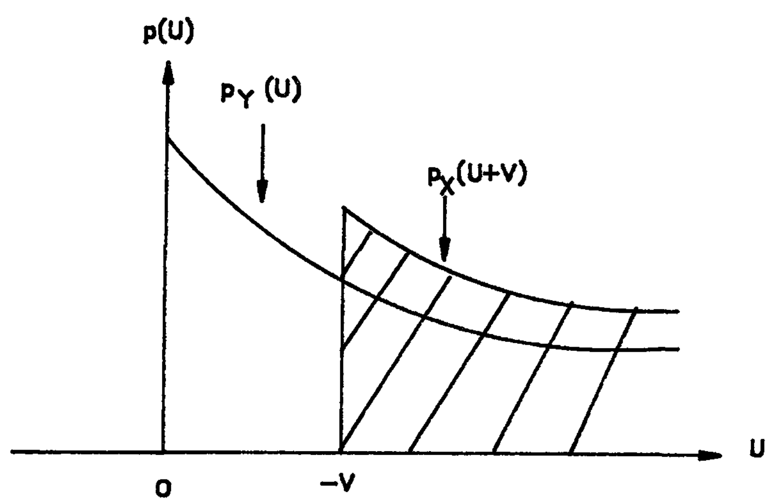


Figure C-2. Integral Geometry for $V < 0$

$$p_V(V) = \frac{1}{(MDT_S)(MDT_C)} \int_{-V}^{\infty} e^{-(U + V)/MDT_S} e^{-U/MDT_C} dU; \; V < 0$$

$$= \frac{e^{-V/MDT_S}}{(MDT_S(MDT_C)} \int_{-V}^{\infty} e^{-U(MDT_S + MDT_C)/(MDT_S)(MDT_C)} dU; \; V < 0$$

$$= \frac{e^{V/MDT_C}}{(MDT_S) + (MDT_C)} \; ; V < 0$$

However, we are seeking E(Z), the expected time of scheduled maintenance greater than corrective maintenance. Hence $p_z(Z)$ must be obtained.

When:

$V < 0; \; Z = 0$

$V \geq 0; \; Z = V$

Thus

$$p_Z(Z) = A\delta(Z) + \frac{e^{-Z/MDT_S}}{(MDT_S + MDT_C)}$$

where

$$A = Prob(Z = 0) = Prob\ (V < 0) = \frac{1}{(MDT_S + MDT_C)} \int_{-\infty}^{0} e^{V/MDT_C} dV$$

$$= \frac{MDT_C}{(MDT_S + MDT_C)}$$

and $\delta(Z)$ is the delta function defined as:

$\delta(Z) = \infty; \; Z = 0$

$\delta(Z) = 0; \; Z \neq 0$

$\int_{-\infty}^{\infty} \delta(Z)dZ = 1$

Thus:

$$p_Z(Z) = \frac{MDT_C}{(MDT_S + MDT_C)} \quad \delta(Z) + \frac{e^{-Z/MDT_S}}{(MDT_S + MDT_C)}$$

By definition:

$$E(Z) = \int_{-\infty}^{\infty} Zp_Z(Z)dZ$$

$$= \frac{MDT_C}{(MDT_S + MDT_C)} \int_{-\infty}^{\infty} Z\delta(Z)dZ + \frac{1}{(MDT_S + MDT_C)} \int_{0}^{\infty} Z\, e^{-Z/MDT_S}\, dZ$$

$$= \frac{(MDT_S)^2}{(MDT_S + MDT_C)}$$

This expression for E(Z) can now be substituted into our equation on page C-3. The resultant expected time attributed to scheduled maintenance is then finally:

$$\bar{S} = \frac{(MDT_S)^2}{(MDT_S + MDT_C)} (1 - e^{-W/MTBF_f}) + MDT_S\, e^{-W/MTBF_f}$$

Since all variables in the above equation are known (MDT_S, MDT_C, W, $MTBF_f$) we can can solve for $\bar{S}$. It can be seen that $\bar{S} \leq MDT_S$ and hence the reduction in maintenance time through the use of this window of opportunity for performing scheduled maintenance.

Appendix D

THE RELATIONSHIP OF STORAGE CAPACITY TO PLANT RELIABILITY, AVAILABILITY, AND MAINTAINABILITY CHARACTERISTICS

This appendix presents a methodology for evaluating the effect of intermediate storage points on the reliability, availability, and maintainability (RAM) characteristics of an electric power plant. The methodology has previously been used in the RAM analysis of a coal-to-methanol plant in the design phase.

A storage point is a storage component (e.g., a holding tank) in a plant process that can continue to feed the downstream processes for a period of time in the event of a failure upstream of the storage point. The storage point masks failures of upstream components that occur and are corrected before the capacity of the storage point is exhausted. From the perspective of the overall system, this masking results in lower than actual failure rates and mean downtimes for the affected components.* Any decrease in component failure and repair parameter value areas, such as the oxygen plant and coal handling systems, can have a significant impact on overall plant availability measures.

The major problem in evaluating the impact of storage point on system reliability is how to determine the expected storage capacity of the storage points. In most cases, the expected storage level and the flow rate out of the storage bin are used to determine the average storage time associated with the storage element. The storage time (ST) is the average time it takes to empty the storage bin and is expressed as:

$$ST = \bar{L}/r_B$$

Where $\bar{L}$ is the average level of the bin; r_B is the flow rate out of the bin.

*When an exponential distribution is assumed for repair times, the effective component mean downtime (MDT) is unchanged; the effective MDT will be lower if other distributions are assumed.

If a failure of one of these affected components will not have an effect on the plant until the stores are depleted, this expression provides the appropriate surge time to apply to upstream components.

There are instances, however, where the storage points have an impact on downstream components; for example, the stream through the storage bin could be a by-product, or waste on its way to a waste-treatment facility. If a failure occurs downstream of waste storage, the plant can continue to operate only until the bin reaches maximum capacity. In this case,

$$ST = (L - \bar{L})/r_A$$

where L is the maximum level of the bin; r_A is the flow rate into the bin.

The assumption was made in the IGCC analysis that storage points would be fully recharged at any failure. Therefore, in the IGCC analysis, the storage time (ST) is equal to the maximum capacity, in hours, of the storage bin.

In an actual plant there may be several storage points, and some could have an additive surge impact on certain components. This can occur when components are directly upstream of two or more surge points, and their failures are buffered by more than one surge capacity. For example, the effective surge time, EFFST(i), for a surge point with upstream impact [with a calculated surge time ST(i)] and two downstream additive surge points would be:

$$EFFST(i) = ST_i + ST_{i+1} + ST_{i+2}$$

This is illustrated as follows:

$$\boxed{C1} \rightarrow \boxed{C2} \rightarrow \boxed{ST_1} \rightarrow \boxed{C3} \rightarrow \boxed{C4} \rightarrow \boxed{ST_2} \rightarrow \boxed{C5} \rightarrow \boxed{C6} \rightarrow \boxed{ST_3}$$

Components C1 and C2 are influenced by the combined storage times of ST_1, ST_2, and ST_3. Therefore, the effective storage time of ST_1 is the sum of ST_1, ST_2, and ST_3. Similarly, the effective storage time of ST_2 is ST_2 plus ST_3.

Effective Component RAM Data Calculations

The storage time is a critical input parameter in the determination of the effective component data. The effective RAM data calculations are based on the probability of a failure lasting longer than the storage time and thus causing a failure in the plant.

For the case of upstream storage impact, λ'_A is that portion of the failure rate of component A that corresponds to system level failure as a result of the storage point being emptied:

$$\lambda'_A = \lambda_A \text{Prob (downtime of A} > ST_B)$$

Assuming constant failure and repair rates

$$\lambda'_A = \lambda_A e^{-\mu_A ST_B}$$

where,

λ_A = the inverse of the actual mean time between failures (MTBF) of component A

μ_A = the inverse of mean downtime (MDT) of component A

ST_B = expected storage time; in the IGCC model, this is the maximum storage time, hours

This equation can be rewritten as

$$MTBF_A = (MTBF_A)e^{ST_B/MDT_A}$$

Since the exponential distribution has been assumed for repair times in this analysis, as noted above, the effective mean downtime is equal to the actual mean downtime:

$$MDT'_A = MDT_A$$

Application of Methodology

To apply the methodology to the IGCC plant RAM analysis, ARINC Research developed an enhancement to the UNIRAM software that adjusts component RAM data using the expressions presented in this appendix. The adjusted data were then used in a RAM assessment model to assess the change in overall plant RAM measures that resulted from consideration of storage effects. The plant availability measures considered in this analysis are availability, effectiveness, equivalent availability, and equivalent forced outage.

Appendix E

ADDITIONAL IGCC PERFORMANCE ESTIMATES
PREPARED BY FLUOR ENGINEERS, INC.

Table E-1

BASELINE IGCC PERFORMANCE ESTIMATES
FROM FLUOR ENGINEERS, INC.

State	Descriptor	Combustion Turbine Power Output (MW)	Steam Turbine Power Output (MW)	Plant Power Consumption (MW)	Net Output (MW)
1	No Failures	409.4	280.6	91.6	598.4
2	1 HRSG Failure	396.8	206.4	89.0	514.2
3	1 Gasifier Failure	328.1	243.2	80.1	491.2
4	1 HRSG Failure and 1 Gasifier Failure	325.1	177.4	78.6	423.9
5	1 C.T. Failure	281.6	182.0	73.0	390.6
6	2 Gasifier Failures	216.6	146.1	51.4	311.3
7	1 Acid Gas Removal Failure	216.6	146.1	51.4	311.3

Table E-2

BASELINE IGCC WITH SUPPLEMENTAL FIRING PERFORMANCE
ESTIMATES FROM FLUOR ENGINEERS, INC.

State	Descriptor	Combustion Turbine Power Output (MW)	Steam Turbine Power Output (MW)	Plant Power Consumption (MW)	Net Output (MW)
1	No Failures	410.6	343.0	101.1	652.5
2	1 HRSG Failure	398.9	274.2	99.9	573.2
5A	1 C.T. Failure	281.1	268.4	81.4	468.1
5B	1 C.T. Failure and 1 Gasifier Failure	281.1	257.5	80.5	458.1

Table E-3

BASELINE IGCC WITH NATURAL GAS BACKUP PERFORMANCE
ESTIMATES FROM FLUOR ENGINEERS, INC.

State	Descriptor	Combustion Turbine Power Output (MW)	Steam Turbine Power Output (MW)	Plant Power Consumption (MW)	Net Output (MW)
3	1 Gasifier Failure	404.1	259.9	80.4	583.6
4	1 Gasifier and 1 HRSG Failure	384.8	192.7	79.1	498.4
6A	2 Gasifier Failures	394.7	213.8	52.8	555.7
7A	1 Acid Gas Removal Failure	394.7	213.8	52.8	555.7
7B	1 Acid Gas Removal and 1 C.T. Failure	275.1	166.3	51.6	389.8

Appendix F

DETAILED DEFINITION OF THE AVAILABILITY STATES

Table F-1

STATE DEFINITIONS

NUMBER OF UNAVAILABLE TRAINS IN EACH SUBSYSTEM

STATE	COAL RECEV. & HANDL.	VIB. FEEDERS	COAL GRIND.	SLURRY HANDLE	OXYGEN PLANT	SLURRY PUMP	GASIF. SCRUB.	ASH	L.T. COOL. ONE TRAIN	L.T. COOL. OTHER TRAIN	ACID GAS	SULFUR REM.	FLARE/ TGT	BFW	C.T./ GEN.	HRSG++	S.T./ GEN.
1	0	< 4	< 2	0	0	< 3	0	0	< 4*	< 4*	0	< 2	< 2	0	0	0	0
2	0	< 4	< 2	0	0	< 3	0	0	< 4*	< 4*	0	< 2	< 2	0	0	1	0
3	0	< 4	< 2	0	0	< 4	1	0	< 6*	< 4*	0	< 2	< 2	0	0	0	0
0	0	< 4	< 2	0	0	< 4	1	0	< 6*	< 4*	0	< 2	< 2	0	0	1	0
5	0	< 4	< 3	0	0	< 4	< 2	0	< 6*	< 4*	0	< 2	< 2	0	1	0	0
5A+	0	< 4	< 2	0	0	< 3	0	0	< 6*	< 4*	0	< 2	< 2	0	1	0	0
5B+	0	< 4	< 2	0	0	< 4	1	0	< 6*	< 4*	0	< 2	< 2	0	1	0	0
5C+	< 2	< 5	< 5	< 2	< 3	< 7	< 5	< 2	< 9*	< 9*	< 3	< 3	< 3	0	1	1**	0
6	0	< 4	< 3	0	0	< 5	2	0	< 6*	< 6*	< 2	< 2	< 2	0	< 2	0	0
6A+	0	< 4	< 3	0	0	< 5	2	0	< 6*	< 6*	< 2	< 2	< 2	0	0	0	0
7	0	< 4	< 3	0	0	< 5	< 3	0	< 6*	< 6*	1	< 2	< 2	0	< 2	0	0
7A+	0	< 4	< 3	0	0	< 5	< 3	0	< 6*	< 6*	1	< 2	< 2	0	0	0	0
7B+	0	< 4	< 3	0	0	< 5	< 3	0	< 6*	< 6*	1	< 2	< 2	0	1	0	0
8	0	4	< 2	0	0	< 4	< 2	0	6,7or8*	1*	0	< 2	< 2	0	0	0	0
9	0	< 4	< 3	0	1	< 5	< 3	0	< 6*	< 6*	< 2	< 2	< 2	0	< 2	0	0
10	0	< 4	< 4	0	< 2	< 6	3	0	< 9*	< 6*	< 2	< 2	< 2	0	< 3	0	0
11	< 2	< 5	< 5	< 2	< 3	< 7	< 5	< 2	< 9*	< 9*	< 3	< 3	< 3	0	0	2	0
12	< 2	< 5	< 5	< 2	< 3	< 7	< 5	< 2	< 9*	< 9*	< 3	< 3	< 3	0	0	4	1
13	< 2	< 5	< 5	< 2	< 3	< 7	< 5	< 2	< 9*	< 9*	< 3	< 3	< 3	0	2	0	0
14	All other possible combinations																

NOTE: The numbers above indicate the number of failed trains within a subsystem. For example, a "2" indicates that two trains within this subsystem have failed whereas a "<2" means that either zero or one train within this subsystem has failed.

* These numbers differ from all others on this table in that they refer to the capacity states defined for the low temperature gas cooling subsystem defined on Figure 2-1. More combinations of "low temperature gas cooling" train capacities are possible beyond those identified above.

** This failed HRSG is NOT series-connected with the simultaneously failed combustion turbine.

\+ These states, identified both by number and alphabetical letter, are subsets of the states which are identified solely by a number.

++ In all states, any HRSG which is series-connected to a failed combustion turbine, can also be failed without impacting plant output.

Appendix G

STATISTICAL UNCERTAINTY ANALYSIS

The statistical uncertainty analysis option in UNIRAM addresses the combined effects on unit reliability, availability, and maintainability (RAM) predictions of uncertainty in individual component failure and repair data items. Use of the uncertainty option requires that at least one component MTBF or MDT be described in the input file through the use of a multiparameter distribution.

A Monte Carlo sampling technique is used to sample component data from the distributions specified in the data file. (When three values are given for either the MTBF or the MDT, then the "distribution" shape used by UNIRAM is triangular.) This sampling procedure is performed a number of times as specified by the UNIRAM user. Statistics on the variations in results are collected for each iteration.

Statistics collected for each iteration are used to determine the 90-percent confidence interval for unit RAM measures. The execution of this statistical uncertainty analysis, using a larger number of samples greater than 50, might yield a mean equivalent forced outage rate (EFOR) closer to the baseline value. However, the mean values given by the uncertainty analysis option will not necessarily converge with the baseline values, because the baseline execution uses the mode of each three-parameter distribution rather than the mean.

Appendix H

GLOSSARY

ABD - Availability Block Diagram. The ABD is a pictorial representation of the "flow" of availability in a plant. The "blocks" within the ABD are subsystems, each of which is represented by a fault tree. Storage points are also depicted in the ABD.

"AND" gate - This is a logic relationship depicted by the character "". When components in a fault tree are connected to a subsystem above by way of an AND gate, then all components under this gate must fail before the subsystem fails.

Availability - Availability is a measure of the percentage of time that some output can be obtained from the plant. It can be calculated as the "service hours" divided by the "period hours." See Figure H-1 at the end of this appendix.

Average heat rate - The average heat rate is a measure of the coal plus natural gas energy used, divided by the net electrical energy output from the plant. The value is an "average," because it is derived by weighting the heat rate for all of the availability states of the plant by the probability of being in each state. This average heat rate differs from other similarly named values used in the utility industry in that the assumption here is that the plant will be operated to the limit that availability will allow. No part-load heat rate effects resulting from economic dispatch are accounted for in these estimates.

Average output while operating - This value is a measure of the output of the plant at each failure mode weighted by the probability of being in each mode or state.

Component - Any plant element for which available data cannot be broken down for assignment to lower-level elements.

Effective MTBF - This is the mean time between failures (MTBF) of a component after adjustments are made to account for the effect of storage. The presence of storage capability downstream of a component tends to mask or reduce the frequency of plant outages experienced as a result of the component's failure. When the storage capacity is sufficient in size to eliminate some short-duration failures, then an effective MTBF can be calculated to account for this.

Effectiveness - Effectiveness is a plant reliability measure that is similar to that of equivalent availability. Effectiveness differs in that it is independent of the scheduled outage rate. See Figures H-1 and H-2 at the end of this appendix for a definition expressed as calculations.

Equivalent availability - Equivalent availability is a measure of the ratio between energy actually produced from the plant and the energy that could have been produced by the plant had there been no failures, deratings, or scheduled maintenance. See calculation Figures H-1 and H-2 (at the end of this appendix).

Equivalent forced outage rate - Equivalent forced outage rate is a measure of the lost energy output due to plant failures and deratings. The equivalent forced outage "rate" is expressed as a percentage. Once this percent figure is divided by 100, you have the "factor," which is calculated in Figures H-1 and H-2 (at the end of this appendix).

Fault tree - This is a diagrammatic method of depicting the relationship between component failures and subsystem failure.

Forced outage rate - This is the full forced outage hours as a fraction of the service hours. It gives a measure of the fraction of time that the plant is unable to produce any output as a consequence of a failure.

GCC - Gasification-combined-cycle (GCC) plants are power plants that gasify coal and then use the resulting coal gas to fuel the combined-cycle section of the plant. These plants are often referred to as IGCCs (integrated gasification-combined cycles) because of the steam integration between the gasification plant and the combined cycle.

IGCC - See GCC.

MDT - MDT or mean downtime (in hours) is the average length of time that a component is out of service as a consequence of any one of all possible types of failures that can occur in that component. This MDT includes plant shutdown time, logistics time for obtaining the needed equipment parts, repair time, and plant startup time.

MTBF - MTBF or mean time between failures (in hours) is the average time between failures for a given component. For example, a component may fail frequently and require a short downtime for repair for one reason, and for another reason it may fail infrequently and require a longer time to repair. The MTBF would be an average that would take into account both failure modes. Likewise, the MDT would be an average that takes into consideration both modes.

"OR" gate - This is a logic relationship depicted by the character " ". When components in a fault tree are connected to a subsystem above by way of an "OR" gate, the entire subsystem will fail if any component under this gate fails.

Output state - A plant can be in any one of a number of states depending on the status of its subsystems. All subsystems can be available, and this represents one state. Alternatively, one or more subsystems can be failed. Each state can be defined or described by the output-limiting subsystem failure. For example, one of two 50-percent subsystems in a plant might fail. The plant would have the same output whether or not, at the same time, none, one, or two (but not three) of the four 25-percent subsystems in the same plant are available. Therefore, the failure of one of the two 50-percent subsystems is sufficient to describe several possible configurations, all of which lead to the same 50-percent plant output state.

Plant state - See "Output state."

Period hours - "Period hours" means all hours of the year including those during which forced or scheduled outages may occur.

RAM - Reliability, availability, and maintainability.

R&M - Reliability and maintainability.

Scheduled outage rate - Scheduled outage rate is that percentage of time that scheduled maintenance is being performed. When this percentage "rate" is multiplied by 100, the result is the scheduled outage factor, which is calculated in Figures H-1 and H-2 (at the end of this appendix).

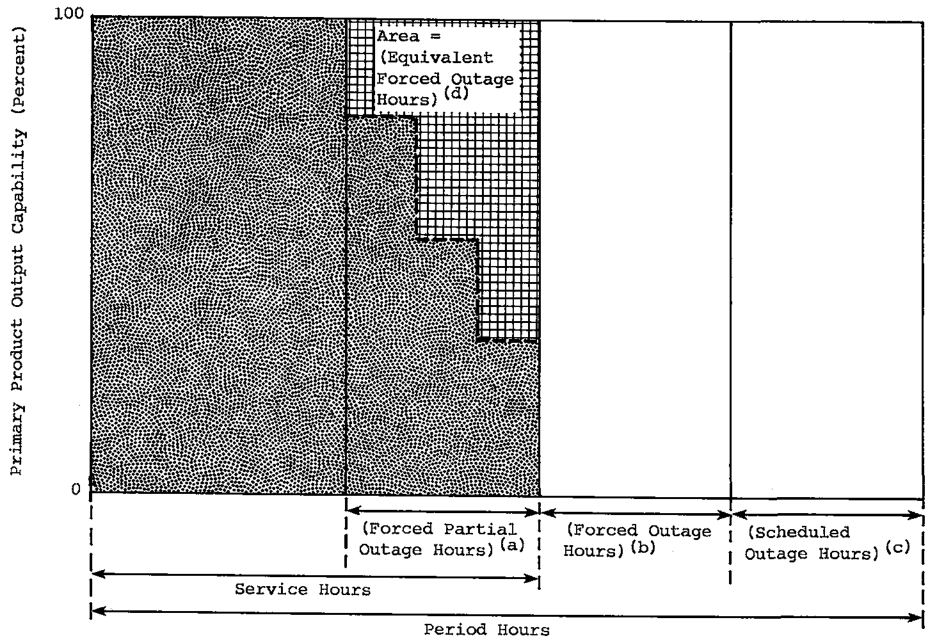
Service hours - The service hours amount to all hours in the year (period hours) minus both the scheduled outage hours and the forced outage hours. See Figure H-1.

State - See "Operating state."

Subsystem - An aggregation of components whose failures have an identical impact on plant operation. A subsystem can have two operating modes: full capacity or zero capacity.

 - See "'AND' gate."

 - See "'OR' gate."



(a) Unplanned Derated Hours, Classes 1, 2, and 3
(b) Unplanned Outage Hours, Classes 1, 2, and 3
(c) Planned Outage Hours plus Unplanned Outage Hours, Classes 4 and 5
(d) Equivalent Unplanned Derated Hours, Classes 1, 2, and 3

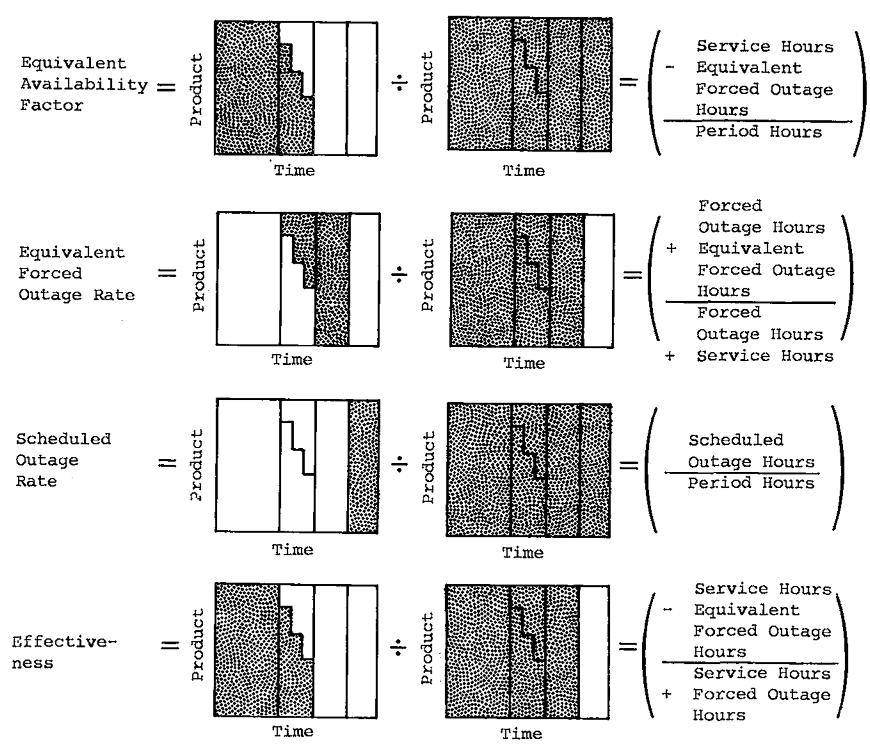


Figure H-1. Availability Measures

SOH = Scheduled Full Outage Hours per Period

PH = Period Hours

EA = Equivalent Availability Factor

SOR = Scheduled Outage Rate

EFOR = Equivalent Forced Outage Rate

E = Effectiveness

$$EA = (1 - SOR)(1 - EFOR)$$

$$SOR = \frac{(EA + EFOR - 1)}{(EFOR - 1)} = \frac{SOH}{PH}$$

$$EFOR = \frac{(EA + SOR - 1)}{(SOR - 1)}$$

$$E = \frac{EA}{(1 - SOR)} = (1 - EFOR)$$

Figure H-2. Relationships Among Reliability Variables