Wabash River Coal Gasification Repowering Project

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EXECUTIVE SUMMARY

The Wabash River Coal Gasification Repowering Project (WRCGRP, or Wabash Project) is a joint venture of Destec Energy, Inc. of Houston, Texas and PSI Energy, Inc. of Plainfield, Indiana, who have jointly repowered an existing 1950's vintage coal fired steam generating plant with coal gasification combined cycle technology. The Project is located in West Terre Haute, Indiana at PSI's existing Wabash River Generating Station. The Project processes locally mined Indiana high sulfur coal to produce 262 net megawatts of electricity.

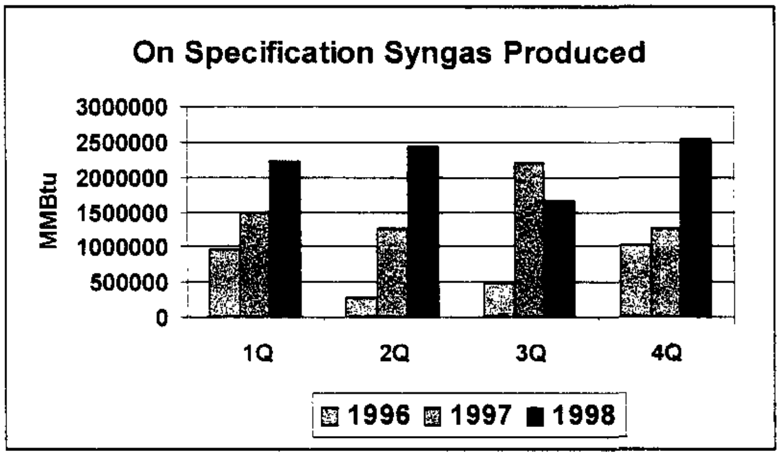
PSI and Destec are participating in the Department of Energy's Clean Coal Technology Demonstration Program (CCT) to demonstrate coal gasification repowering of an existing generating unit affected by the Clean Air Act Amendments. As a CCT Round IV selection, the project will demonstrate integration of an existing PSI steam turbine generator and auxiliaries, a new combustion turbine generator, heat recovery steam generator, and a coal gasification facility to achieve improved efficiency, reduced emissions, and reduced installation costs.

Reaching completion in 1995, the Project represents the largest single train coal gasification combined cycle power plant in the United States. Its design allows for lower emissions than other high sulfur coal fired power plants and a resultant heat rate improvement of approximately 20% over the existing plant configuration.

In July of 1998, Destec Energy changed its name to Dynegy, Inc. (reflective of a 1997 purchase of Destec by NGC Corporation of Houston, Texas). All further references in this report to Destec will be replaced with "Dynegy" to reflect this name change. The facility identity of "Gasification Services, Inc." remained the same through the acquisition and subsequent name change of the parent corporation to Dynegy.

During 1998 the gasification facility operations team focused on the third commercial year of operation. The following key objectives were set for 1998:

- Continue improvement of the Dry Char system to include an evaluation of element metallurgy
- Evaluate gasifier temperature control to aid in prevention of ash deposition
- Achieve an increasingly effective understanding of the systems and subsystem operating characteristics
- Obtain the data base and experience base necessary to advance and meet the commercial markets for the technology.



1998 marked the third full year of commercial operation of the facility. The chart at left illustrates the quantity of syngas produced during each quarter of 1998, while at the same time showing the comparison with the prior two years of operation. In the first quarter the plant produced over 2,217,000 MMBtu's of syngas while establishing a new continuous coal run record of 479 hours of operation. Also, during March, the plant topped the 1 trillion Btu production level for a single month (for the first time since beginning operation in 1995) by producing 1.16 trillion Btu's. Ash deposition decreased in the 1st quarter indicating that efforts that began in 1997 were having a positive effect on plant operations. The second quarter of 1998 continued to produce production records by re-setting the continuous coal run hours to 514 hours and by producing over 2,434,000 MMBtu's during the quarter. The second quarter also saw the first alternative coal (Miller Creek) feed stock introduced into the system, which presented several production and operational challenges to the production staff. Third quarter operations were impacted by the problems associated with the new coal feed stock. Slag flow characteristics of the new coal were directly responsible for a plugged reactor taphole during the quarter creating excessive down time to clean the system. Fourth quarter operations set new records by producing 1,215,321 MMBtu's of syngas in the month of November. The fourth quarter production of syngas established a new quarterly production record of over 2,530,000 MMBtu's. Although total hours on coal were slightly below second quarter figures, higher operating rates coupled with increased efficiency allowed the plant to produce more syngas than in any previous quarter.

The Wabash Project achieved several additional operational milestones in 1998, including:

- Plant availability above 75%,
- First operational run on an alternate coal (Miller Creek) and blended feed stocks (Miller Creek/Hawthorne),
- Gasification plant operates on coal for 5,279 hours producing 8,832,869 MMBtu's of on-specification syngas,
- Combustion turbine operates on syngas for 5,139 hours,
- Operational procedural changes improve availability,
- Test Dry char filter elements evaluated by utilizing a side stream unit,
- Dynegy's gasification process earns the Indiana Governor's Award for Excellence in Recycling.

Major milestones and activities projected for 1999 include evaluation of new project installations, performance monitoring of the Dry Char Recovery System filtration efficiency, continued focus on gasifier operations, and continued demonstration of the commercial viability of the project.

INTRODUCTION

In September 1991 the United States Department of Energy (DOE) selected the Wabash River Coal Gasification Repowering Project (WRCGRP) for funding under Round IV of the DOE's Clean Coal Technology Demonstration Program. This was followed by nine months of negotiations and a congressional review period. The DOE executed a Cooperative Agreement on July 28, 1992. The project's sponsors, PSI Energy, Inc., and Destec Energy, Inc. (now Dynegy), will demonstrate, in a fully commercial setting, coal gasification repowering of an existing generating unit affected by the Clean Air Act Amendments (CAAA). The project will also demonstrate important advances in the coal gasification process for high sulfur bituminous coal. After receiving the necessary state, local and federal approvals, this project began construction in the third quarter of 1993 and commercial operations in the third quarter of 1995. This facility has a planned three-year demonstration period and 22 year operating period (25 years total).

The WRCGRP is a joint venture of Dynegy and PSI Energy, who have developed, designed, constructed, own and now operate a coal gasification facility and a combined cycle (CGCC) power plant (respectively). This specific coal gasification technology, originally developed by The Dow Chemical Company and now owned by Dynegy, was used to repower Unit 1 of PSI's Wabash River Generating Station in West Terre Haute, Indiana. The CGCC power plant produces a nominal 262 net megawatts (MWe) of clean, energy efficient capacity for PSI's customers. In the repowered configuration, PSI and its customers can additionally benefit because this project can enhance PSI's compliance plan under the CAAA regulations. The project utilizes locally mined high sulfur coal and represents the largest CGCC power plant in operation in the United States. This plant is also designed to significantly lower emissions from those of other high sulfur coal fired power plants.

BACKGROUND INFORMATION

Project Inception and Objectives

For CCT Round IV, Public Law 101-121 provided $600 million to conduct cost-shared CCT projects to demonstrate technologies that are capable of replacing, retrofitting, or repowering existing facilities. To that end, a Program Opportunity Notice (PON) was issued by the Department of Energy in January 1991, soliciting proposals to demonstrate innovative energy efficient technologies that were capable of being commercialized in the 1990's. These technologies were to be capable of: (1) achieving significant reductions in the emissions of sulfur dioxide and/or nitrogen oxides from existing facilities to minimize environmental impacts such as transboundary and interstate pollution and/or; (2) providing for future energy needs in an environmentally acceptable manner.

In response to the PON, 33 proposals were received by the DOE in May 1991. After evaluation, nine projects were selected for award. These projects involved both advanced engineering and pollution control technologies that can be "retrofitted" to existing facilities and "repowering" technologies that not only reduce air pollution but also increase generating plant capacity and extend the operating life of the facility.

One of the nine projects selected for funding is the project proposed by the WRCGRP Joint Venture. This proposal (a Joint Venture between Destec Energy, Inc. (Dynegy) of Houston, Texas and PSI Energy, Inc. of Plainfield, Indiana) requested financial assistance from DOE for the design, construction, and operation of a nominal 2500 ton-per-day (262 net MWe) two-stage, oxygen-blown, coal gasification combined cycle (CGCC) repowering demonstration project. The project, named the Wabash River Coal Gasification Repowering Project, is located at PSI's Wabash River Generating Station in West Terre Haute, Indiana. The project location and site are shown in Figures 1, 2, 3, and 4 in Appendix B. The demonstration project utilizes advanced coal gasification technology in a commercial repowering setting to repower an existing generating unit affected by the Clean Air Act Amendments of 1990. Sulfur emissions from the repowered generating unit will be reduced by more than 90%, while at the same time increasing electrical generating capacity over 150%. The project, including the demonstration phase, will last 79 months. The DOE's share of the project cost will be $219 million.

<u>The CGCC system consists of:</u> (See Figures 5 & 5A)

- Dynegy's oxygen-blown, entrained flow, two stage coal gasifier, which is capable of utilizing high sulfur bituminous coal;
- An air separation unit;
- A gas conditioning system for removing sulfur compounds and particulate;
- Systems or mechanical devices for improved coal feed and all necessary coal handling equipment;
- A combined cycle power generation system wherein the gasified coal syngas is combusted in a combustion turbine generator;
- A heat recovery steam generator.

The result of repowering is a CGCC power plant with low environmental emissions (SO_2 of less than 0.25 lbs/MMBtu and NO_x of less than 0.1 lb/MMbtu) and high net plant efficiency. The repowering increases unit output, providing a total CGCC capacity of nominal 262 net MWe. The project demonstrates important technological advancements in processing high sulfur bituminous coal.

In addition to the joint venture members, PSI and Dynegy, the Phase II project team included Sargent & Lundy, who provided engineering services to PSI. and Dow Engineering, who provided engineering services to Dynegy.

The potential market for repowering with the demonstrated technology is large and includes many existing utility boilers currently fueled by coal, oil, or natural gas. In addition to greater, more cost effective reduction of SO_2 and NO_x emissions attainable by using the gasification technology, net plant heat rate is improved. This improvement is a direct result of the combined cycle feature of the technology, which integrates a combustion topping cycle with a steam bottoming cycle. This technology is suitable for repowering applications and can be applied to any existing steam cycle located at plants with enough land area to accommodate coal handling and storage and the gasification and power islands.

One of the project objectives is to advance the commercialization of coal gasification technology. The electric utility industry has traditionally been reluctant to accept coal gasification technology and other new technologies as demonstrated in the U.S. and abroad because the industry has no mechanism for differentiating risk/return aspects of new technologies. Utility investments in new technologies may be disallowed from rate-base inclusion if the technologies do not meet performance expectations. Additionally, the rates of return on these are regulated at the same level as established lower risk technologies. Therefore, minimal incentives exist for a utility to invest in, or develop, new technologies. Accordingly, most of the risk in new technologies has traditionally been assumed by the supplier.

The factors described above are constraints to the development of, and demand for, clean coal technologies. Constraints to development of new technologies also exist on the supply side. Developers of new technologies typically self-finance or obtain financing for projects through lenders or other equity investors. Lenders will generally not assume performance and operational risks associated with new technology. The majority of funds available from lending agencies for energy producing projects is for technologies with demonstrated histories in reliability, maintenance costs and environmental performance. Equity investors who invest in new energy technologies also seek higher returns to accept risk and often require the developer of the new technology to take performance and operational risks.

Consequently, the overall scenario results in minimum incentives for a commercial size development of new technologies. Yet without the commercial size test facilities, the majority of the risk issues remain unresolved. Addressing these risk issues through utility scale demonstration projects is one of the primary objectives of DOE's Clean Coal Technology Program.

The WRCGRP was developed in order to demonstrate the Dynegy Coal Gasification Technology in an environment, and at such a scale, as to prove the commercial viability of the technology. Those parties affected by the success of this Project include the coal industry, electric utilities, ratepayers, and regulators. Also, the financial community, which provides the funds for commercialization, is keenly interested in the success of this project. Without a demonstration satisfying all of these interests, the technology will make little advancement. Factors of relevance to further commercialization are:

- The Project scale (262 net MWe) is compatible with all commercially available advanced gas turbines and thus completely resolves the issue of scale-up risks.

- The operational term of the Project is expected to be approximately 25 years including the DOE demonstration period of the first 3 years. This should alleviate any concerns that the demonstration does not define a fully commercial plant from a cost and operational viewpoint.

- The Project dispatches on a utility system and is called upon to operate in a manner similar to other utility generating units.

- The Project operates under a service agreement that defines guarantees of environmental performance, capacity, availability, coal to gas conversion efficiency and maximum auxiliary power consumption. This agreement serves as a model for future commercialization of the Dynegy Coal Gasification Technology and defines the fully commercial nature of the Project.

- The Project is designed to accommodate most coals available in Indiana and typical of those available to Midwestern utilities, thereby enabling utilities to judge fuel flexibility. The Project also enables testing of varying coal types in support of future commercialization of the Dynegy Coal Gasification Technology.

Plant Description

The WRCGRP Joint Venture participants developed and separately designed, constructed, own, and currently operate the syngas and power generation facilities making up the CGCC facility. Coal Gasification technology owned by Dynegy, is used to repower one of six units at PSI's Wabash River Generating Station in West Terre Haute, Indiana. The Project will operate under a 25 year contact. In the repowered configuration, PSI and its customers additionally benefit because of the role the Project plays in PSI's Clean Air Act compliance plan. The CGCC power plant produces 262 net MWe of clean, energy efficient, cost effective capacity for PSI's customers. An additional economic benefit to the State of Indiana is that the project not only represents the largest CGCC power plant in operation, but also features lower emissions than other large, high sulfur coal fired power plants.

The gasification process can be described in the following manner: (see Figures 6 and 7 in Appendix B): Coal is ground with water to form a slurry and then pumped into a gasification vessel where oxygen is added to form a hot, raw gas through partial combustion. Most of the non-carbon material in the coal melts and flows out the bottom of the vessel as slag (a black, glassy, non-leaching, sand like material). The hot, raw gas is then cooled in a heat exchanger to generate high-pressure steam. Particulates, sulfur, and other impurities are removed from the gas to make acceptable fuel for the gas turbine. By-products of the gasification process (e.g. sulfur and slag) will be sold thus mitigating the waste disposal problems of competing technologies.

The synthetic fuel gas (syngas) is piped to a combustion turbine generator, which produces approximately 192 MWe of electricity. A heat recovery steam generator (HRSG) recovers gas turbine exhaust heat to produce high-pressure steam. This steam, combined with the steam generated in the gasification unit, supplies an existing steam turbine generator in PSI's plant to produce an additional 104 MWe. The net plant heat rate for the entire new and repowered unit is approximately 9,000 Btu/kWh (Higher Heating Value or HHV), representing an improvement of approximately 20% over the existing unit. The project heat rate is among the lowest of commercially operated coal fired facilities in the United States.

The Dynegy Coal Gasification process was originally developed by The Dow Chemical Company during the 1970's in order to diversify its fuel base. The technology being used at Wabash is an extension of the experience gained from pilot plants and the full-scale commercial facility, Louisiana Gasification Technology, Inc. (LGTI), which operated from April 1987 until November 1995.

In order to generate data necessary for commercialization, the Joint Venture has chosen a very ambitious approach for incorporation of novel technology in the project. This approach is supported by PSI's desire to have another proven technology alternative available for future repowering or new base load units. Dynegy desires to enhance its competitive position relative to other clean coal technologies by demonstrating new techniques and process enhancements as well as gaining information about operating cost and performance expectations. The incorporation of novel technology in the project will enable utilities to make informed commercial decisions concerning the utilization of Dynegy's technology, especially in a repowering application.

New enhancements, techniques and other improvements included in the novel technology envelope for the project are as follows:

- **A novel application** of integrated coal gasification combined cycle technology will be demonstrated at the project for the first time – **repowering of an existing coal fired power generating unit.**

- The **coal fuel** for the project **is high sulfur bituminous coal**, thus demonstrating the environmental performance and energy efficiency of Dynegy's advanced two-stage coal gasification process. Previous Dynegy technology development has focused on lower rank, more reactive coals.

- **Hot/Dry particulate removal/recycle will be demonstrated at full commercial scale** by the project. Destec's plant, LGTI, utilized a wet scrubber system to remove particulates from the raw syngas.

Other coal gasification process enhancements included in the project to improve the efficiency and environmental characteristics of the system are as follows:

- **Syngas Recycle** provides fuel and process flexibility while maintaining high efficiency.

- **A High Pressure Boiler** cools the hot, raw gas by producing steam at a pressure of 1,600 pounds per square inch absolute (psia).

- **The Carbonyl Sulfide (COS) Hydrolysis** system incorporated at the project is Dynegy's first application of this technology. This system is necessary to attain the high level of sulfur removal at the project.

- **The Slag Fines Recycle** system recovers most of the carbon present in the slag by-products stream and recycles it back for enhanced carbon conversion. This also results in a high quality slag by-product.

- **Fuel Gas Moisturization** is accomplished at the project by the use of low level heat in a concept different from that used by Dynegy before. This concept reduces the steam injection required for nitrous oxide (NO_x) control in the combustion turbine.

- Sour water, produced by condensation as the syngas is cooled, is processed differently from the method used at LGTI. This novel **Sour Water System**, used at the project, allows more complete recycling of this stream, reducing waste water and increasing efficiency.

- An oxygen plant producing **95 percent pure oxygen** is used by the project. This increases the overall efficiency of the project while lowering the power required for production of ultra-pure oxygen.

- The **power generation facilities** included in the project incorporates the latest advancements in combined cycle system design while accommodating design constraints necessary to repower the existing Unit 1 steam turbine.

- The project incorporates an **Advanced Gas Turbine** with a new design compressor and higher pressure ratios.

- **Integration between the Heat Recovery Steam Generator (HRSG) and the Gasification Facility** has been optimized at the project to yield higher efficiency and lower operating costs.

- **Repowering of the Existing Steam Turbine** involved upgrading the unit in order to accept increased steam flows generated by the HRSG. In this manner, the cycle efficiency is maximized because more of the available energy in the cycle will be utilized.

The gasification/repowering approach offers the following advantages as compared to other options:

- This is a viable alternative that will add life to existing older units. The primary assumption, however, is that reasonable life exists in the steam turbine to be repowered. If reasonable life exists in the steam turbine, the approach eliminates the need for refurbishment of much of the high wear components of conventional pulverized coal units. Three such items are the boiler, coal pulverizers and high energy piping systems.

- This approach is an alternative for Clean Air Act compliance compared with the traditional scrubber approach. Although space constraints are similar for the installed facility, waste storage requirements are smaller due to salable by-products in lieu of onsite storage of scrubber sludge.

- This approach provides a use for high sulfur coal. This is particularly important in areas such as Indiana, and much of the eastern United States, where high sulfur coal is abundant and provides a substantial employment base.

Project Management

The WRCGRP Joint Venture established a Project Office for the execution of the project. The Project Office is located at Dynegy's corporate offices in Houston, Texas. All management, reporting, and project reviews for the project are carried out as required by the Cooperative Agreement. The Joint Venture partners, through a Joint Venture Agreement, are responsible for the performance of all engineering, design, construction, operation, financial, legal, public affairs, and other administrative and management functions required to execute the project. A Joint Venture Manager has been designated as responsible for the management of the project. A Joint Venture organization chart is shown as Figure 8. The Joint Venture Manager is the official point of interface between the Joint Venture and the DOE for the execution of the Cost Sharing Cooperative Agreement. The Joint Venture Manager is responsible for assuring that the Project is conducted in accordance with the cost, schedule, and technical baseline established in the Project Management Plan (PMP) and subsequent updates.

Major Activities and Milestones

The Project Cooperative Agreement was signed on July 28, 1992, with an effective date of August 1, 1992. Under the terms of the Cooperative Agreement, Project activities are divided into three phases:

- Phase I Engineering and Procurement
- Phase II Construction and Startup
- Phase III Demonstration

In addition, for purposes of the Cooperative Agreement, the Project is divided into three sequential Budget Periods. The expected duration of each budget period is as follows:

- Budget Period 1 10 months
- Budget Period 2 27 months
- Budget Period 3 39 months

The Project Milestone Schedule is provided in Figure 9.

Phase I Activities – Engineering and Procurement

Under the provisions of the Cooperative Agreement, the work activity in Phase I (engineering and procurement) focused on detailed engineering of both the syngas and power plant elements of the project which included design drawings, construction specifications and bid packages, solicitation documents for major hardware and the procurement. Site work was undertaken during this time period to meet the overall construction schedule requirements. The Project Team includes all necessary management, administrative and technical support.

The activities completed during this period were those necessary to provide the design basis for construction of the plant, including capital cost estimates sufficient for financing, and all necessary permits for construction and subsequent operation of the facility.

The work during Phase I can be broken down into the following main areas:

- Project Definition Activities
- Plant Design
- Permitting and Environmental Activities

Each of these activities is briefly described below. All Phase I activities were complete by 1993.

Project Definition Activities

This work included the conceptual engineering to establish the project size, installation configuration, operating rates and parameters. Definition of required support services, all necessary permits, fuel supply, and waste disposal arrangements were also developed as part of the Project Definitions Activities. From this information, the cost parameters and project economics were established (including capital costs, project development costs and operation and maintenance costs). Additionally, all project agreements necessary for construction of the plant were concluded. These include the Cooperative Agreement and the gasification services agreement.

Plant Design

This activity included preparation of design and major equipment specifications along with plant piping and instrumentation diagrams (P&ID's), process control releases, process descriptions, and performance criteria. These were prepared in order to obtain firm equipment specifications for major plant components, which established the basis for detailed engineering and design.

Permitting and Environmental Activities

During Phase I, applications were made and received for the permits and environmental activities necessary for the construction and subsequent operation of the project. The major project permits included:

- Indiana Utility Regulatory Commission – The state authority reviewed the project (under a petition from PSI for a Certificate of Necessity) to ensure the project will be beneficial to the state and PSI ratepayers. The technical and commercial terms of the project were reviewed in this process.

- Air Permit – This permit details the allowable emission levels for air pollutants from the project. It was issued under standards established by the Indiana Department of Environmental Management (IDEM) and the United States Environmental Protection Agency (USEPA) Region V. This permit also included within it the authority to commence construction.

- NPDES Permit – This National Pollutant Discharge Elimination System permit details and controls the quality of waste water discharge from the project. It was reviewed and issued by the Indiana Department of Environmental Management. For this project it will be a modification of the existing permit for PSI's Wabash River Generating Station.

- NEPA Review – The National Environmental Policy Act review was carried out by the DOE based on project information provided by the participants. The scope of this review was comprehensive in addressing all environmental issues associated with potential project impacts on air, water, terrestrial, quality, health and safety, and socioeconomic impacts.

Miscellaneous permits and approvals necessary for construction and subsequent operation of the project included the following.

- FAA Stack Height/Location Approval
  Controlling Authority: Federal Aviation Administration

- Industrial Waste Generator
  Controlling Authority: Indiana Department of Environmental Management

- Solid Waste

- FCC Radio License

- Spill Prevention Plan

- Wastewater Pollution Control Device Permit
  Controlling Authority: IDEM

Phase II Activities – Construction

Construction activities occurred in Phase II and included the necessary construction planning and integration with the engineering and procurement effort. Planning the construction of the project began early in Phase I. Separate on-site construction staffs for both Dynegy and PSI were provided to focus on their respective work for each element of the Project. Construction personnel coordinated the site geotechnical surveys, equipment delivery, storage and lay down space requirements. The construction activities included scheduling, equipment delivery, erection, contractors, security and control.

The detail design phase of the project includes engineering, drawings, equipment lists, plant layouts, detail equipment specifications, construction specification, bid packages and all activities necessary for construction, installation, and startup of the project.

Performance and progress during this period was monitored in accordance with previously established baseline plans. There were no Phase II activities conducted during this reporting period.

Phase III Activities – Demonstration Period

Phase III consists of a three-year demonstration period. The operation effort for the project began with the development of the operating plan including integration with the early engineering and design work of the project. Plant operation input to engineering was vital to assure optimum considerations for plant operations and maintenance and to assure high reliability of the facilities. The operating effort continued with the selection and training of operating staff, development of the operating manuals, coordination of startup with construction, planning and execution of plant commissioning, conduct and documentation of the plant acceptance test, and continued operation and maintenance of the facility throughout the demonstration period.

Phase III activities are intended to establish the operational aspects of the project in order to prove the design, operability and longevity of the plant in a fully commercial utility environment.

Budget Periods

For ease of administration, the Project is divided into three budget periods with expected durations of:

- Budget Period 1 10 months
- Budget Period 2 27 months
- Budget Period 3 39 months

Budget Period 1 activities include pre-DOE award and project definition tasks, preliminary engineering work, and permitting activities. Budget Period 2 activities include detailed engineering, procurement, construction, pre-operations training tasks, and startup. Budget Period 3 activities include the three-year demonstration period. The budget period costs were originally projected and revised as follows:

	Original	Revised
Budget Period 1 DOE Share	$43,175,801	$21,864,591
Budget Period 2 DOE Share	$102,523,632	$144,934,842
Budget Period 3 DOE Share	$52,300,567	$52,300,567
Total	$198,000,000	$219,100,000

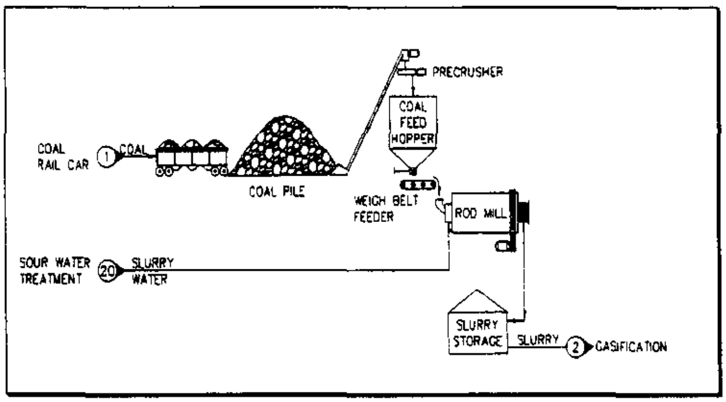
ACTIVITIES DURING 1998

A current Project schedule, indicating milestone dates and current status, is provided as Figure 10.

1998 Phase III Activities – Demonstration Period

The plant processes are broken down by area to better describe the activities during 1998 and focus on the accomplishments and areas identified for improvement. Each area is preceded by an illustrated representation of the process along with a general process description.

COAL PREPARATION AND SLURRY AREA



The diagram at left depicts the process of coal slurry preparation. PSI has the responsibility of delivering coal and transporting it to the feed hopper. Coal enters the feed hopper then is fed to the rod mill via a weigh belt feeder. In 1998 all coals processed originated in Indiana and included both Hawthorne and Miller Creek coal. The coal is mixed with limestone (if required based on ash fusion temperature) at the mine site, which is added as a fluxing agent to enhance slag flow characteristics in the gasifier. Limestone addition is not necessary for lower ash fusion coals. Treated water recycled from other areas of the gasification process is added to the coal at a controlled rate to produce the desired slurry solids concentration of approximately 62%. The use of a wet rod mill reduces potential fugitive particulate emissions from the grinding operations. Collection and reuse of water within the gasification process minimizes water consumption and effluent wastewater volume.

The slurry is stored in an agitated tank, which is large enough to supply the gasifier needs during forced rod mill outages. Most expected maintenance requirements of the rod mill and storage tank can thus be accomplished without interrupting gasifier operation.

All tanks, drums, and other areas of potential atmospheric exposure of the product slurry or recycle water are covered and vented into the tank vent collection system for vapor emission control. The entire slurry preparation facility is paved and curbed to contain spills, leaks, wash down, and rain water. All runoff is carried by a trench system to a sump where it is pumped into the recycle water storage tank to be reused in the coal slurry preparation system.

Primary coal characteristics, which effect operation of the gasifier include the following:

- Ash Content
- Sulfur
- Carbon
- Hydrogen
- Nitrogen
- Oxygen
- Btu Content

The following table illustrates the average values for these constituents in 1998 while also outlining the variability that was encountered during the year:

	Hawthorne Coal			Miller Creek Coal***		
	Average	**High**	**Low**	**Average**	**High**	**Low**
Ash, %	13.5	14.91	11.41	12.07	12.43	11.35
Sulfur, %	2.85*	3.53**	2.52	3.45	3.99	3.08
Carbon, %	69.58	71.5	65.89	71.36	71.48	71.20
Hydrogen, %	4.55	4.84	4.00	4.69	4.86	4.43
Nitrogen, %	1.08	1.55	0.75	1.38	1.48	1.24
Oxygen, %	8.48	12.26	7.02	7.06	8.26	6.08
Btu/lb (Received)	10645	10407	10820	10765	10919	10635
Btu/lb (Dry)	12566	12976	12276	12890	12984	12801

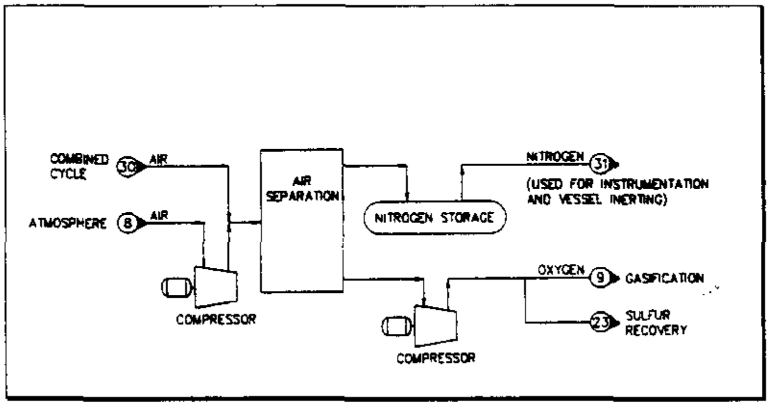
* May be artificially high due to some Miller Creek and Hawthorne Coal blends
** Suspected Miller Creek and Hawthorne Coal blends
*** Coal train analysis

The rod mill is designed to crush the coal to a desired particle size to ensure stable "slurryability" and optimum carbon conversion in the gasifier. Due to problems encountered in 1997 with foreign material being processed from the coal pile and through the rod mill, rod mill rod charge and trommel screen damage has been carefully tracked throughout the year. The trommel screen is designed to prevent oversized particles and debris from entering the slurry storage tank. Problems with holes in the trommel screen appeared again in 1998 but the results were minor compared to previous years. To reduce the occurrences of holes in the screen, a steel band has been added to the end of the screen. Preventative Maintenance (PM) inspections have been increased on the screen and the incidences of failure have been almost eliminated. Optimum slurry concentration (62%) is carefully monitored and rods replaced as necessary to ensure system performance. In the fourth quarter, a slight increase in routine rod charge led to an increase in the amount of fine particles in the slurry, which resulted in increased reactivity of the particles in the gasifier. This had a slight positive impact on the cold gas efficiency for the quarter. Overall, the coal preparation and slurry area was responsible for only 0.3% of the total plant downtime in 1998.

In 1998 a total of over 561,494 tons (as received) of coal were processed through the rod mill. Slurry fed from the slurry feed tank to the gasifier accounted for approximately 12,071,728 MMBtu's. The following table illustrates the quarterly usage of coal feed stock in 1998:

1998	**"As Received" Coal Feed (Tons)**	**MMBtu**
1st Quarter	142,894	3,063,742
2nd Quarter	160,737	3,356,936
3rd Quarter	104,301	2,255,146
4th Quarter	153,562	3,395,904
Total	**561,494**	**12,071,728**

AIR SEPARATION UNIT (ASU)



The Air Separation Unit (ASU) depicted at left, contains: an air compression system; an air purification and cryogenic distillation system; an oxygen compression system; and, a nitrogen storage and handling system. Atmospheric air is compressed in a centrifugal compressor then cooled in a chiller tower to approximately 40 degrees F. The cooled air is then purified through molecular sieve absorbers where atmospheric contaminants (H_2O, CO_2, hydrocarbons, etc.) are removed to prevent these contaminants from freezing during cryogenic distillation. The dry, carbon dioxide-free air is separated into 95% purity oxygen, high purity nitrogen, and waste gas in the cryogenic distillation system. The gaseous oxygen is compressed in a centrifugal compressor and fed to the gasifier. Liquid nitrogen (LIN) is also produced in the distillation system with a portion being vaporized for use as gaseous nitrogen in the gasification system and the balance being stored for use during ASU plant outages.

In 1998 the ASU contributed 397 hours of gasification plant downtime (approximately 20.4% of total downtime) compared to 198 hours (or approximately 7.1%) in 1997. While these hours are elevated for 1998, it is important to note that production from the ASU increased from approximately 328,000 tons in 1997 to over 442,000 tons in 1998. Nitrogen shortfalls, while still occurring in 1998, have been reduced by careful application of operating and startup procedures incorporated into the system in 1997 and continuing in 1998.

Several key outages occurred in 1998 which led to the increase in ASU contributions to plant downtime. Those occurrences were:

- In January, a Westinghouse control I/O power supply experienced a blown fuse resulting in loss of power to multiple automatic operated valves. This, in turn, forced a gasification plant trip via an oxygen compressor shutdown in the ASU resulting in five hours of lost production. The second lost production incident occurred later in January when the anti-surge valve protecting the main air compressor (MAC) failed to open when required and once open, failed to close under normal control. As increased loading of the MAC is essential to close the surge valves, operating staff loaded the MAC coincident to field technicians successfully closing the surge valves. This resulted in pressure safety valves (PSVs) opening and failing to reseat. The PSVs required overhaul and resulted in 35 lost production hours. A third event occurred in January, when the MAC tripped due to excessive vibration resulting from malfunction of the inlet guide vane electronic positioning system, which loads the compressor. The net effect was a production loss equal to 53 hours. Root cause investigations were launched to determine and correct the events preceding each malfunction.

Evidence suggested the first incident was a result of an amperage load imbalance for the control circuit and a relatively simple redistribution of load proved successful in preventing further occurrence. The sticking surge valve was related to actuator corrosion due to extended operation with only minor valve movement. A simple preventative maintenance plan now calls for full-stroke actuator operation and lubrication during all shutdown periods. Design deficiency was responsible for the guide vane failure resulting in increased system maintenance (short term) and a request for proposal to replace the actuator system (long term).

- In February, a high voltage switch-gear fuse (15 KV) failed forcing both the MAC and oxygen compressors to shutdown resulting in 33 hours of downtime. No apparent cause was found for the blown fuse in the high voltage system, so no modifications or predictive measures could be identified to prevent recurrence of this event.

- On June 8th and 9th, production delays occurred resulting from packing fires inside the chiller tower during vessel entry work. A total of 61 hours in startup delays resulted from this event. Evidence suggested the incident resulted from inadequate fire barriers and failure to use a low energy welding technique such as heli-arc over stick welding, which emits a molten slag shower up to 10 feet in diameter.

- An additional lost production incident occurred June 17th, when the oxygen compressor coupling housing began to smoke and was observed leaking oil. Investigation revealed a blocked oil discharge orifice, which forced the coupling housing to accumulate oil. At over 11,000 rpm, the coupling added energy to the liquid rapidly resulting in a boiling oil vapor release. A total of 26 hours of lost production were attributed to this event. Mediocre orifice design was responsible for the boiling oil incident. The orifice hole was placed in the bottom of the plate, which was subject to plugging by debris exiting with the oil. In addition, the orifice was 50% obstructed by the discharge flange due to poor placement. To remedy the problem a second orifice was placed in the center of the plate to allow particulate settling prior to oil discharge.

- On August 9th an incident occurred when the power card for the main air compressor inlet guide vane, programmable logic controller failed. Difficulties in lining out the ASU after the controller failed prevented the gasification island from operating for 110 hours. A voltage surge consistent with a probable lightning strike was identified as the root cause for the power card failure.

- On August 15th, production was lost when a high voltage (15 kV) potential transformer (PT) blew a primary fuse in the motor control center (MCC) switchgear. Both the oxygen and main air compressors in the ASU utilize the PT for voltage reference in their field excitation controllers and for under-voltage protection. Although neither machine suffered a failure, the blown fuse shut down both compressor motors instantaneously via the power factor relay. The potential transformer was exposed to a battery of megger tests, turns ratio and inductive Doble™ measurements. All testing confirmed no problem with the potential transformer equipment but suggested a problem upstream of the primary side of the PT (fuse itself or 15kV system). Fuse amperage rating was calculated and confirmed to provide sufficient factor of safety. Since this was the second type failure on the series PT fuses, the PT itself was swapped with an identical type from less critical service to ensure reliability. Any repeated failure will confirm a problem with the high voltage equipment.

While the above mentioned outages represent the bulk of the plant downtime associated with the ASU, minor failures in the operation and equipment availability of this system also contributed to overall downtime. The following events were noted in 1998 along with the appropriate actions taken to prevent recurrence:

- Short production interruptions occurred on July 19th totaling several hours. These were the result of a manual feed disruption in response to a lost level signal for the low-pressure distillation column. Operational procedures have been put into place to prevent recurrence.

- On August 4th, a nine-hour production loss occurred when the oxygen compressor shutdown from the simultaneous activation of six safety interlocks. The root cause was determined to be a loose wire on the power supply to the fast digital input card for the oxygen compressor.

- On October 8th, a five-hour production interruption occurred due to a power disruption to the Bently-Nevada vibration monitoring cabinet. An analyzer technician accidentally tripped the power toggle while working inside the cabinet for installation of a new data collection system. This resulted in all vibration interlocks "failing safe", shutting down both main air and oxygen compressors. A ten-hour interruption occurred on October 27th and followed actuator problems associated with the adsorption process valves. The actuator worked itself loose from the valve resulting in a limit switch failure, which prevented the regeneration sequence from completing. This halted operation until a full regeneration cycle could be completed for the adsorption bed. Root cause investigations were initiated to determine and correct the elements preceding each malfunction.

Evidence isolated the major cause of both incidents to be human error. Work within the Bently-Nevada cabinet was postponed until the next scheduled outage to prevent further production interruptions. Additionally, a sign was posted on the cabinet door warning of plant shutdown potential due to unprotected power switching inside the cabinet. Training was initiated for all ASU operators regarding the maintenance work request policy and all related aspects of adsorption process control troubleshooting. New and modified alarms were placed in the DCS control to facilitate problem identification.

Several projects were implemented in the ASU in 1998 to enhance industrial hygiene and plant performance. Those projects were:

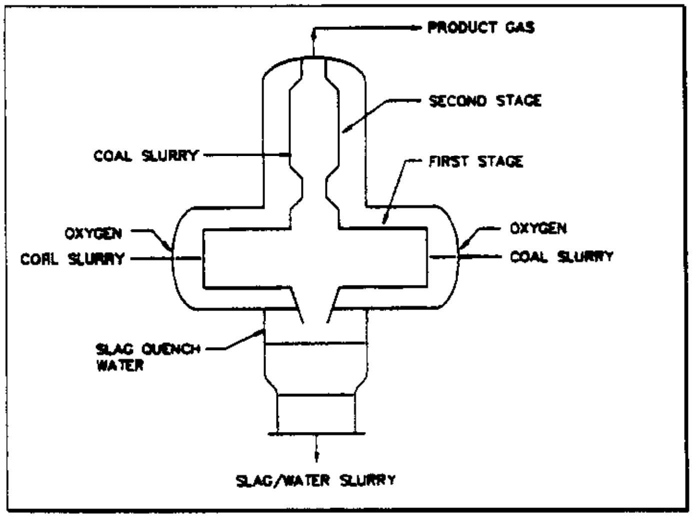
- In the second quarter an ancillary silencer was placed onto the adsorber tower exhaust vents reducing peak noise levels in the area from 105 dB to below 87 dB.

- The nitrogen vaporizer bellows trap and condensate pump systems were eliminated in favor of a float and thermostatic steam trap. The bellows trap system requires sub-cooled condensate for effective steam separation, which resulted in poor vaporizer performance due to backlogged condensate within the vaporizer shell. In addition to enhanced nitrogen delivery, energy and maintenance savings will return the invested capital many fold as the unreliable condensate pump is not necessary with the new system.

- The adsorber regeneration heater gas distribution system was overhauled with enhanced stiffening supports. Once installed, the regeneration heat peaks improved roughly 25 °F, increasing efficiency and reducing cycle time.

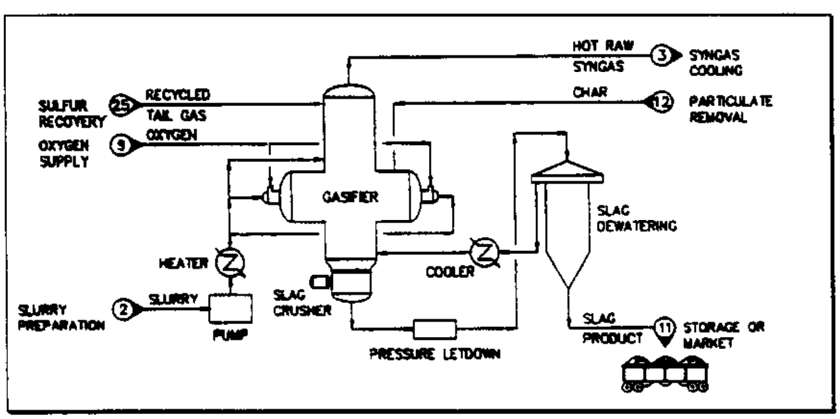
- The failed water distribution system within the chiller tower was reinforced with stiffening elements to prevent liquid channeling and inherent performance problems. A temperature drop of 5 °F is attributed to the improved water distribution. In the fourth quarter, both liquid oxygen pumps were fitted with a solids purge system. This new system will increase liquid oxygen pump bearing life by eliminating the primary source of bearing wear, namely particulate.

GASIFICATION AND SLAG HANDLING

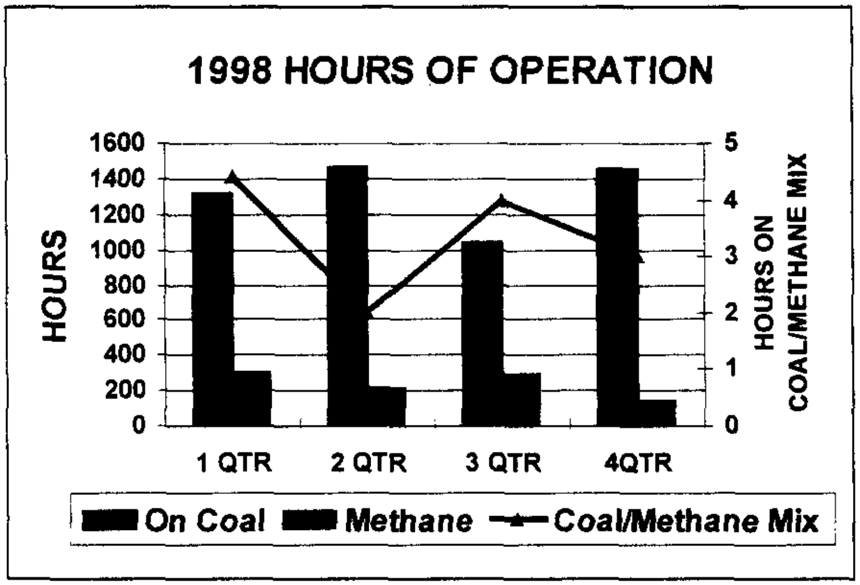


The Dynegy gasifier consists of two stages; a slagging first stage, and an entrained flow, non-slagging second stage. The first stage is a horizontal, refractory lined vessel in which coal slurry and oxygen are combined in partial combustion quantities at an elevated temperature (nominally 2500 degrees F) and pressure (400 psia). Dry particulate (char) filtered from the raw sygnas downstream of the gasifier is also recycled to the first stage gasification process. The oxygen and coal slurry are fed to the gasifier and atomized through two opposing mixing nozzles once the vessel has been adequately preheated on natural gas (methane) operation. Oxygen feed rate to the mixers is carefully controlled to maintain the gasification temperature above the ash fusion point, thereby ensuring good slag removal. Produced synthetic gas (syngas) consists primarily of hydrogen, carbon dioxide, carbon monoxide and water vapor. Sulfur in the coal is converted primarily to hydrogen sulfide with a portion converted to carbonyl sulfide. Both sulfur species are removed in downstream processes. Mineral matter in the coal forms a molten slag, which is continuously tapped from the gasifier. The second stage is a vertical refractory lined section in which additional coal slurry is reacted with the hot syngas stream exiting the first stage. This additional slurry serves to lower the temperature of the gas exiting the first stage to 1900 degrees F by vaporization of the slurry and endothermic reactions. The coal undergoes de-volatilization and pyrolysis thereby generating more gas at a higher heating value. No additional oxygen is added to the second stage. The partially reacted coal (char) and entrained ash is carried overhead with the gas. Natural gas (methane) is utilized for preheating the gasifier. No product syngas is generated for PSI's consumption during the pre-heat process while in methane operations.

Slag flows continuously through the tap hole of the first stage into a water quench bath, located below the first stage. The slag is then crushed and removed through a continuous pressure let-down system as a slag/water slurry. This process of continuous slag removal is compact, minimizes overall height of the gasifier structure, eliminates the high-maintenance requirements of problem-prone lock hoppers, and completely prevents the escape of raw gasification products to the atmosphere during slag removal.

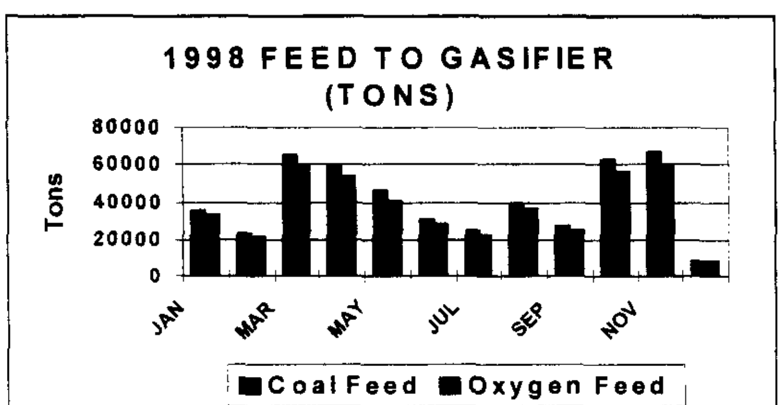


The slag slurry leaving the pressure let down system flows into a de-watering bin. The bulk of the slag will settle out in this bin, while the water overflows a weir at the top of the bin to a settler in which the slag fines are settled and removed. The clear water gravity-flows out of the settler and is pumped through heat exchangers where it is cooled as the final step before being returned to the gasifier quench section. De-watered slag is loaded into a truck or rail car for transport to market or its storage/disposal site located on the south end of the Wabash River Generating station. The fines slurry from the bottom of the settler is recycled to the slurry preparation area. The de-watering system contains de-watering bins, a water tank, cooler and water circulation pump. All tanks, bins, and drums are vented to the tank vent collection system to limit fugitive emissions.



During GSI's operational campaigns in 1998, the gasifier operated on coal 5,278 hours, which represented an increase over 1997 operations of 144%. During heat-up operations, the gasifier operated on methane and a blend of coal/methane for over 976.4 hours (963 hours on methane, and 13.4 hours on a coal/methane mix). These hours have been substantially reduced from a 1997 total of 1,490 hours illustrating increased operator attention, newly established procedures to limit startup time and consume less methane for heat up operations, and less unscheduled outages. It must be reiterated that syngas generated during heat-up operations is not suitable for use as fuel for the combustion turbine and that coal/methane mix is simply a measure of transition from methane heat-up to coal operation. Methane operations indicated in the graph above indicate methane and coal/methane mix hours for heat-up of the gasifier and associated equipment and the transition onto full coal operations.

Coal feed to the gasifier totaled over 561,494 tons for 1998 and oxygen feed from the ASU to the gasifier totaled in excess of 442,000 tons. This material feed was utilized in the production of over 8.832,869 MMBtu of on-spec syngas. By-product slag produced from the process totaled approximately 70,228 tons.



In 1998 the Gasification and Slag Handling area contributed approximately 14.7%, or 286 hours, of downtime due to associated equipment failures or operational difficulties encountered with the alternate coal feedstock. Ash deposition from the gasifier to the inlet of the high temperature heat recovery unit appears to be well under control and did not contribute to downtime in 1998.

Slurry Mixers: Slurry mixers continue to be a source of downtime due to the corrosive/erosive nature of the slurry (and slurry/oxygen mix) and efforts continued throughout 1998 to improve the design and operation of these units. The following is an overall summary of downtime contributors and the corrective actions taken, or in progress, for the year:

- Two coal runs in early January were ended in a controlled fashion when a slurry mixer failure became evident by excessive cooling media loss from the mixer. A third similar mixer failure occurred during the first run of February and resulted in a controlled transfer off of coal operations. Investigation of these incidents revealed that the coal swap was being made at rates nearly 40% higher than in the past. This resulted in high flame temperatures during startup, which accelerated slurry mixer failure. Following these failures, the coal swap procedure was re-emphasized so that the swap will be carried out at a more moderate rate to avoid excessive temperatures when transitioning to coal.

- Despite the above operational improvements, a fourth slurry mixer failure occurred in early March. However, unlike the previous three failures, which exhibited excessive cooling media loss, this failure was traced to a failure in the oxygen feed section of the mixer. The other mixer was shut down in a controlled fashion to take the gasifier off line and allow change out of the failed mixer, which was eroded by the coal/water slurry. Inspections of these parts are now carried out with greater scrutiny during mixer rebuilds to address necessary repairs or replacement of these components to avoid similar failures.

- In early August, following an oxygen compressor trip, some difficulty was experienced returning to coal operations. As oxygen feed was initiated to the mixer, the gasifier tripped on high temperature. The root cause was traced to a slag mound in front of the mixer, which prevented proper mixing of the oxygen and slurry and resulted in high temperatures. To remove slag mounds after oxygen plant trips, a procedural change was implemented requiring the reactor to be de-slagged longer before returning to coal operations.

- Newly designed mixers, intended to enhance slurry/oxygen mixing, were installed in the gasifier late in 3Q98. While they were in service, the gasification plant was able to make capacity at slurry rates as low as 220 gpm per side (versus typical rates of 230-235 gpm).

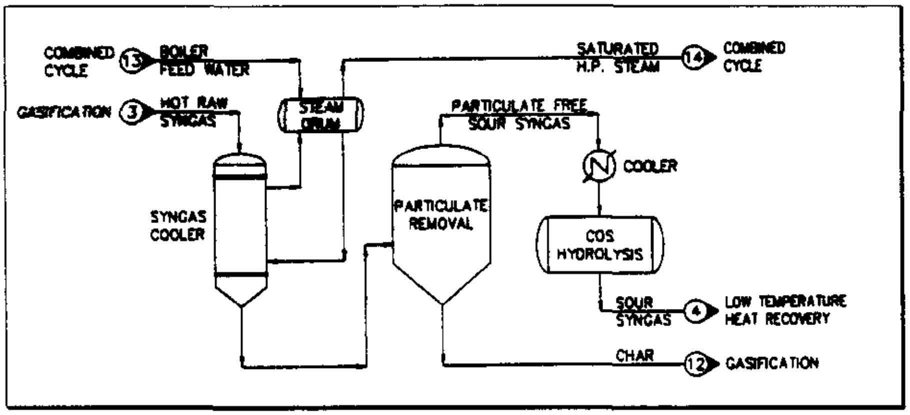
- In early October an internal cooling media leak was detected on one of the mixers, so both were replaced following the main air compressor trip. Internal inspection of the mixers revealed that swirling flow aggravated the erosion of the mixer throat by changing the oxygen and slurry flow pattern. The accelerated erosion significantly shortened the mixer life. Both design and material changes to the slurry mixers will continue in an effort to lower O&M cost. When coal operations resumed with standard mixers, no appreciable difference in gasifier performance was observed due to mixer operation.

Tap hole Plugging: The "tap hole" refers to the transition opening located in the center of the horizontal section of the gasifier that allows slag to flow into the slag quenching section. Plugging becomes a problem when characteristics of the slag change, which effect the ability of the non-gasified portion of the coal to flow as a liquid. The following events contributed to downtime in 1998 as a direct result of tap hole plugging:

- Operations were terminated in the second quarter, for an extended outage of 20 days, when a gasifier tap hole plug forced the unit off of coal operations. Subsequent de-slagging attempts on methane operations were unsuccessful so the gasifier was shutdown for manual removal of the plug. Investigation revealed that slag had not only plugged the tap hole but bridged over the grinders as well, which prevented slag from exiting the gasifier. The root cause of the incident appears to be due a combination of events. Higher slag viscosity in the Miller Creek coal was the primary factor, but this was exacerbated by the fact that the gasifier was run slightly cooler due to fouling problems in the high temperature heat recovery unit (HTHRU) and high-level excursions in the dry char recovery vessel. Improved knowledge of Miller Creek slag behavior and new operating guidelines allowed successful gasifier operation on various blends of Miller Creek and Hawthorn coal for the remainder of the year. Since implementation of the new guidelines, no unusual slag flow or ash deposition problems have been noted as a result of using Miller Creek coal.

- A tap hole plug during methane operation pre-empted coal operations in late December. Preliminary investigation indicates that an ash deposit fell from the second stage gasifier and blocked the tap hole, which had been re-bricked during the December outage. Maintenance personnel were able to clear the plug within the space of four days and heat up operations were reinitiated.

SYNGAS COOLING, PARTICULATE REMOVAL AND COS HYDROLYSIS

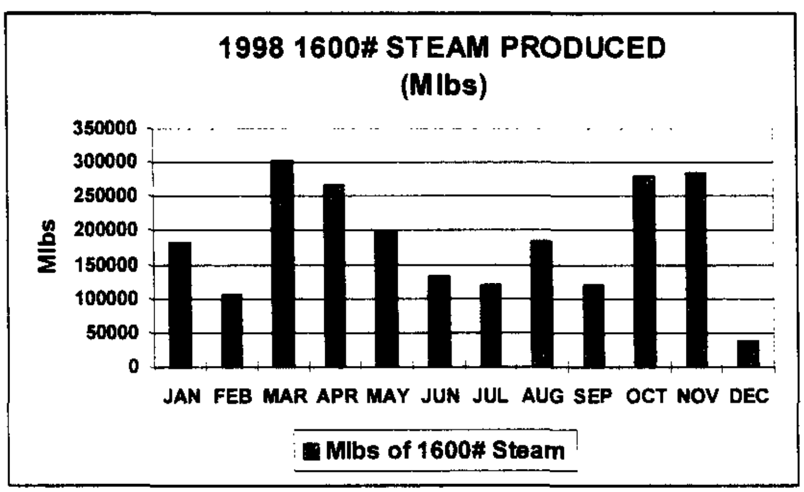


The gas and entrained particulate matter exiting the gasifier system is cooled below 1900 degrees F in a firetube heat recovery boiler system where saturated high pressure steam is produced. Steam from this High Temperature Heat Recovery Unit (HTHRU) is superheated in the HRSG for use in power generation.

The raw gas leaving the HTHRU passes through a barrier filter unit to remove the particulates. The recovered particulates are recycled to the first stage of the gasifier. The particulate free gas is cooled further before proceeding to the carbonyl sulfide (COS) hydrolysis unit.

COS is present in the hundreds of ppm concentration range and is not removed as efficiently as hydrogen sulfide (H_2S) by the Acid Gas Removal (AGR) system. In order to obtain a high sulfur removal level, the COS is converted to H_2S before the sour syngas enters the AGR. This is accomplished by catalytic reaction of the COS with water vapor to create H_2S and carbon dioxide (CO_2). The H_2S formed is removed in the AGR section and the majority of the CO_2 continues on with the raw syngas to the turbine.

Steam production, as shown in the graph at right, tracks the operational run history of the gasifier. Total 1600 psig steam production for 1998 was approximately 2,214 million pounds. This figure represents a production increase of approximately 129% over 1997 and a production in excess of 269% over 1996 steam production figures.



Operational difficulties and opportunities for improvement identified in 1998 will be broken down into the primary processes in this system. The three primary processes are identified as: HTHRU, particulate removal (dry char), and COS hydrolysis. Each component of this system is critical to the overall production capability of the gasification process. The following major events effected overall operation of this system in 1998:

HIGH TEMPERATURE HEAT RECOVERY UNIT (HTHRU)

Gas path flow characteristics changed with the implementation of several projects in 1997, which reduced ash deposition in the gas path up to the inlet screen of the HTHRU. However, inlet screen deposition/corrosion and boiler deposition continued to be of primary concern in 1998 and accounted for 254 hours of downtime (or 13.1% of total downtime for the plant).

- Although not directly responsible for downtime in the first quarter, heavy fouling of the HTHRU (boiler) continues to cause the unit to operate at elevated syngas outlet temperatures. While this does not pose an imminent problem with the HTHRU, elevated syngas temperatures (in combination with the acid gas environment) cause accelerated corrosion rates downstream. Attempts to remove the deposits off-line with high-pressure hydro-blast rigs, mechanical scrapers, and knockers have been unsuccessful. It is suspected that the unusual tenacity of the scale seen in February may be associated with the petroleum coke trial operation late in 1997. Solubility studies conducted on one tube of the boiler during the February outage, indicate that the deposition can be chemically softened, which may assist the cleaning operation. The test solvent removed a significant portion of the deposition and a mechanical cleaning apparatus is currently being designed to allow full-scale cleaning of the unit. Additionally, resultant corrosive wear of the main structural members of the boiler inlet screen necessitated a rebuild of the screen during the February outage.

- During a May/June outage an unsuccessful attempt was made to mechanically remove deposition from the HTHRU tubes. Mechanical cleaning with various types of rotary bits was attempted but proved to be inefficient and resulted in very little change in the HTHRU outlet syngas temperature. In the third quarter, however: a chemical cleaning utilizing the test solvent procedure, mentioned above, was completed with much more success. The chemical cleaning loosened the scale, which was readily removed by subsequent hydro-blasting. Upon returning to operation, an approximate 100°F decrease in HTHRU syngas outlet temperature was noted.

Boiler fouling is a long-term problem that will need to be addressed due to the expense of chemical cleaning as well as the risk of dry char element corrosion while running with a high boiler outlet temperature.

- In June, while operating with Miller Creek coal as a primary feedstock, boiler fouling accelerated due to the coal's ash composition. A significant increase in boiler syngas outlet temperature was also observed as the unit continued to operate on the Miller Creek coal feedstock. By the end of June, when the boiler was opened during an outage, a significantly increased degree of deposition was found on the tube-sheet screen and boiler tubes. The boiler fouling experienced while processing Miller Creek coal was determined to be caused by the higher iron content in the ash. Iron reduces the viscosity of molten ash entrained in the gas, which increases its tendency to adhere to surfaces such as the boiler screen and tube walls. It was found that by running the boiler inlet temperature cooler. the ash viscosity increases, thus minimizing its fouling characteristics. In August, utilizing a lower boiler inlet temperature, the plant successfully processed a 25% Miller Creek/Hawthorne blend with acceptable boiler fouling when compared to the initial run in June. However, fouling and plugging of the boiler continued to be a run limiting concern during the fourth quarter campaign. During a scheduled December outage, cleaning of the tenacious scale continued to cause higher than desired maintenance cost. The combination of a core drill and a mechanical scraper had to be utilized to clean the boiler tubes. Operations and engineering personnel will continue to review operating procedures and investigate HTHRU tube cleaning mechanisms into 1999 to reduce maintenance costs.

PARTICULATE REMOVAL (DRY CHAR FILTRATION)

The dry char recycle system is used to remove fine char and ash from the syngas stream and recycle it back to the first stage of the gasifier. In the recycle process, raw syngas (with entrained char and ash) first enters two parallel primary filters at a temperature of approximately 700 degrees F. The char is filtered as it flows vertically through tubular filter elements contained within the primary vessels. The char and ash form a cake on the exterior surface of the filter, which is periodically back-pulsed with high-pressure syngas, dislodging the cake from the filter. It then drops by gravity to the bottom of the conical-shaped outlet of the filter unit where it is drawn from the vessel and recycled back to the gasifier. Past performance of this system has indicated that inlet temperature. char loading, back-pulse gas temperature, and composition and design of the filter elements play critical roles in the operation of this system. In 1997 the dry char system accounted for approximately 25% (706 hours) of total plant down time. In 1998, through an increased understanding of system operation and continuing research into filter element composition and design, plant downtime due to the dry char system was reduced to 180 hours or only 9.3% of total downtime for the plant.

The following key areas of operation and mechanical malfunction were responsible for the majority of the downtime for 1998:

- The high temperature particulate removal system continued to experience high primary filter blinding rates, initially experienced in the fourth quarter of 1997, until the February outage. In February, new filter elements with increased resistance to blinding were installed. The particulate removal system operated with minimal primary filter blinding until early in the third quarter when, during an outage the filter system required cleaning and some replacements of filter elements. Due to supply constraints of the newer filter elements, older elements more susceptible to blinding were reinstalled in July. The high blinding rate limited the length of the subsequent run to the first week in September. A combination of old and new style elements was installed in September to maximize run time and minimize cost.

- Due to concerns over further element and inlet gas distributor damage, the plant was taken off line in the middle of May due to char breakthrough only one week before a scheduled outage date. The root cause of the filter failure was identified as corrosion of some of the filter elements due to elevated sour syngas temperatures throughout the dry char system (created by upstream fouling of the HTHRU).

- Dry char motive-gas ejector life, which was a problem in 1997, has been improved through the use of proper preventative maintenance procedures and improved materials of construction. In late April the system was shutdown for a scheduled inspection and no run limiting damage was observed on either ejector. However, one of the ejectors was proactively replaced with a modified ejector, designed for improved erosion resistance. Proactive replacement did not prevent an internal dry char ejector failure later in the run campaign due to a manufacturing error (during the unit's previous rebuild). The failure resulted in a high level in the dry char vessel and caused swings in the reactor temperature when char was emptied from the vessel. These thermal excursions, combined with the high slag viscosity associated with Miller Creek coal, resulted in gasifier tap hole plugging problems that ended second quarter operations. Failed dry char ejectors again contributed to downtime in July and August. Operations were terminated on July 28th and August 28th to allow change out of failed ejector motive gas nozzles. The plant continued to operate on methane during the ejector change so downtime was limited to about 3-4 hours in each instance. The newly designed char recycle ejectors lasted through the entire fourth quarter run campaign with no evidence of deteriorating performance.

- While changing the failed ejector in August, a back-pulse valve was also changed due to leak-by when in the closed position. Upon return to coal operations, a second back-pulse valve was discovered to be leaking. The run was terminated to allow replacement of the valve. The root cause of the failures appear to be high pulse gas temperatures that result when the pulse gas heater, used during start-up operations, is left in service after coal operation is established. Operations personnel have been instructed on the proper use of this heater to avert future pulse valve failures. Additionally, two pulse valves were taken out of service in the fourth quarter due to failure to provide a pulse. Inspection revealed that a retaining nut had come loose which prevented the valve plunger from coming off the seat. Improperly torqued retaining nuts were identified as the likely cause of the problem. During the subsequent outage, the retaining nuts on all 36 back pulse valves were torqued to the proper specification.

- The first run following the third quarter scheduled outage was terminated due to a leak, and subsequent fire, on the primary dry char filtration vessel inlet flange. The leak is suspected to have resulted from pipe movement encountered when new inlet ball valves were installed in this system (discussed below). Installation of the ball valves did not include inspection of downstream piping so it is possible that a shift in the flanges would lead to a breach in the gasket-sealing surface. The leak was wire wrapped and clamped to allow safe return to operation with a permanent repair made at the next planned outage. Inspection during a fourth quarter outage confirmed that misalignment of the sealing surfaces was indeed the root cause of this incident. While this was an isolated case that can be associated with project implementation in a very specific area, engineering has been advised to consider inspecting associated equipment and piping when movement within the system occurs during installation.

Several projects/equipment enhancements were made to the dry char system to enhance performance and/or to improve operability. The following were accomplished in 1998:

- A test cluster of ceramic filters, previously tested off-line in the slipstream unit, was installed in one of the primary vessels for evaluation. To avoid jeopardizing plant availability, failsafe devices were installed to prevent char breakthrough if a filter element failed. The failsafe devices were installed after extensive testing and evaluation and are used as a back up to the primary dry char filters. The failsafe device is a highly porous filter used to capture solids that might breakthrough the primary filter elements. These devices were installed on all alloy candle elements that were most susceptible to corrosion related failures.

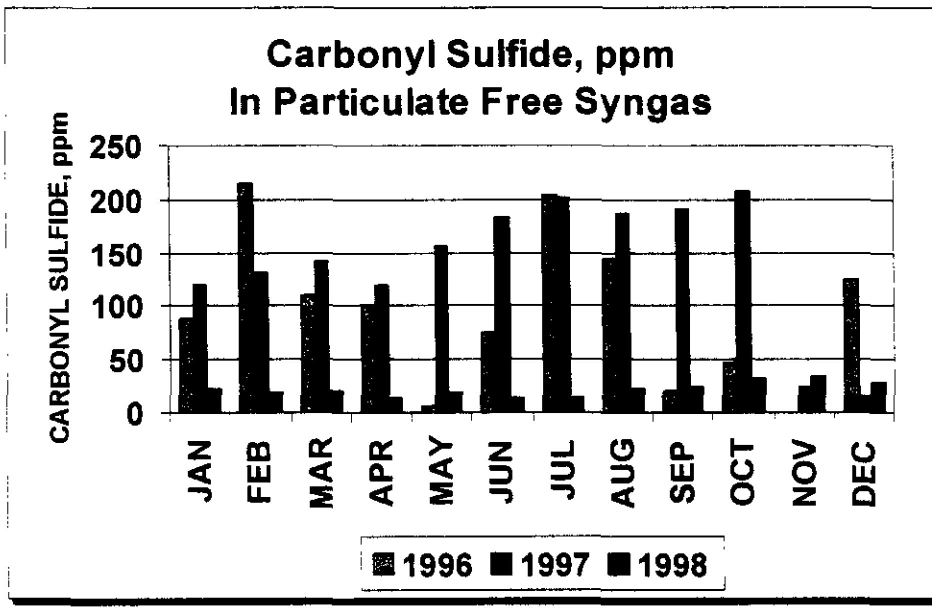
- Additionally, testing continued on several corrosion resistant candle filter alloys, which yielded some promising results. Corrosion rate data suggests that one of these alloys could more than double the life of the filters currently in service.

- The butterfly valves at the inlet to the particulate removal system were replaced with 24" ball valves during the September outage. Positive shutoff with the previous valves was impossible resulting in extended cooling and heating times for shutdowns and startups, respectively.

- Initial testing of an improved seat design for the hot gas filter system back-pulse valves was conducted. The evaluation proved the new design to be much more reliable than the original style valve seats. Consequently, all back-pulse valves were converted to the improved seat design. This eliminated all of the valve failure problems previously associated with seat failures.

CARBONYL SULFIDE HYDROLYSIS

The primary purpose of the carbonyl sulfide (COS) hydrolysis unit is to convert COS to H_2S. COS cannot be effectively removed from downstream processing and must be converted to H_2S to facilitate removal in the amine process. Conversion and subsequent removal of the COS results in lower total reduced sulfur (TRS) in the product syngas and lower sulfur dioxide emissions from the combustion turbine exhaust stack.

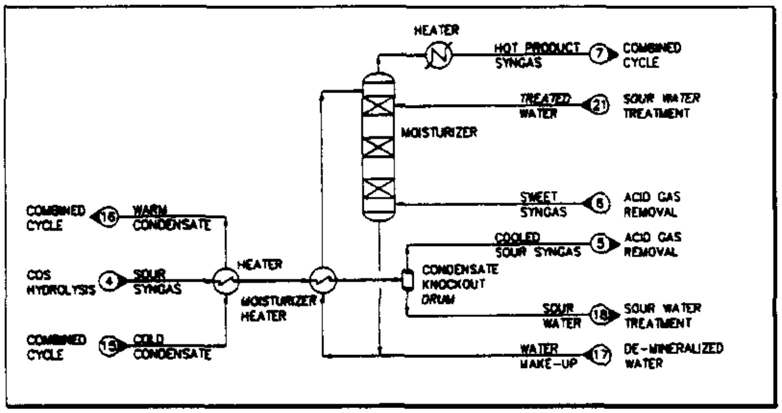


The chart at left depicts ppm levels of COS on a comparative basis between 1996, 1997 and 1998. As is illustrated by this graph, significant progress has been made in the control of COS from the hydrolysis unit and in operating the system on a more consistent basis. In 1996 the average ppm level of COS leaving the hydrolysis unit was 102.9 ppm, while the 1997 average increased to 139.4 ppm. These high values were due to catalyst contamination by arsenic and chlorides in 1996 and to partial degradation in 1997, resulting from a deflagration incident which reduced the total surface area of the catalyst and promoted channeling through the reactor bed. 1998 reflects the first year of optimum operation, as is indicated by an average value of 26.78 ppm of COS in the product syngas. This was achieved following catalyst bed replacement in the fourth quarter of 1997, and illustrates the capabilities of this unit when it is properly operated and maintained.

The chloride scrubbing system, installed in 1996 after chlorides were identified as a contaminant to the COS catalyst, plays an essential role in syngas preparation prior to COS hydrolysis. By removing a substantial portion of the chlorides entrained in the syngas, it not only protects the COS catalyst but also reduces the potential of chloride stress-corrosion cracking of the tube bundles in the Low Temperature Heat Recovery Unit (LTHRU). The chloride scrubbing system operated within design specification during 1998 with only minor problems associated with fouling of the de-mister pads and associated vessel packing.

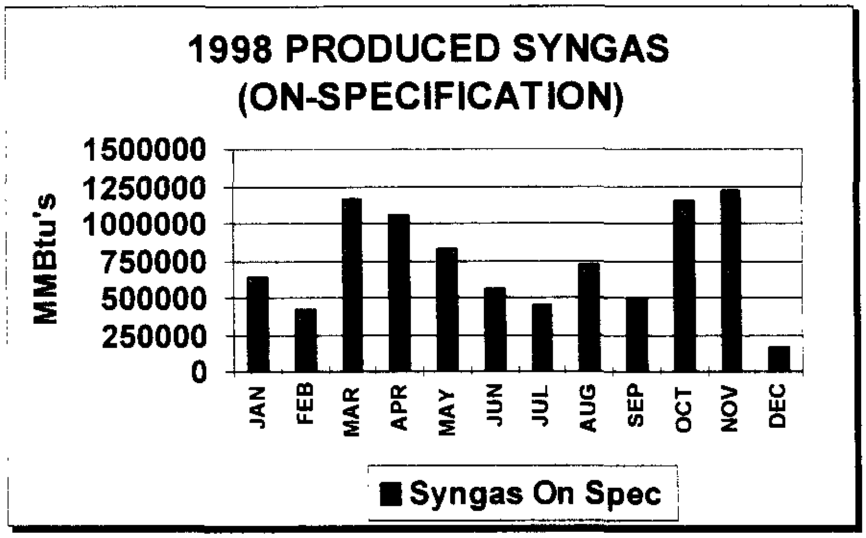
By emphasizing upstream control of contaminants (char and chlorides) in the syngas, operation and maintenance of the COS hydrolysis unit has been of minimal concern in 1998.

LOW TEMPERATURE HEAT RECOVER AND SYNGAS MOISTURIZATION



After exiting the COS hydrolysis unit, the remaining low level heat is removed from the syngas in a series of shell-and-tube exchangers located before the Acid Gas Recovery (AGR) system. This cooling condenses water, ammonia, carbon dioxide, and some hydrogen sulfide (H_2S) which produces sour water. The sour water is collected in the condensate knockout drum and sent to the sour water treatment unit. The heat removed prior to the AGR system provides moisturizing heat for the product syngas, steam for the AGR H_2S stripper, and condensate heat.

Cooling water provides trim cooling to ensure the syngas enters the AGR near its design temperature (approximately 100 degrees F). The cooled sour syngas is fed to an absorber in the AGR system where the solvent selectively removes H_2S to produce a sweet syngas low in total reduced sulfur. The sweet syngas is then moisturized to a water content of approximately 22%, by volume, using low level heat from raw syngas cooling. Moisturization is accomplished by contacting the sweet syngas and hot water counter-currently in a high surface area contacting column. After the moisturizer, the syngas is preheated before being directed to the combustion turbine. Moisturization and preheating of the syngas increases efficiency in the combustion turbine and reduces the steam requirement for NO_x control.



Sweet syngas (product syngas) production for 1998 totaled 8,857,869 MMBtu's with the highest production occurring in the fourth quarter. This production equals 142.7% of the production record set in 1997. Fourth quarter production set a new quarterly production record of 2.503,587 MMBtu's. This quarter included a scheduled December outage for maintenance and repair. Sweet syngas moisturization operated efficiently and provided a consistent product gas moisture content of approximately 20%-23% throughout 1998. Product syngas quality remained high and will be discussed later in this section.

The LTHRU contributed a total of 7 hours of plant downtime in 1998. While this is not significant enough to warrant concern, several key opportunities for operation and maintenance improvements were identified. The following areas of concern were noted during the 1998 operational period:

- Following an off-line cleaning of one of the exchangers during a maintenance outage, one of the LTHRU exchangers was hydro-tested for leaking tubes due to suspected failure. Approximately twenty tubes were found leaking and were subsequently plugged on both ends. One tube was extracted for failure analysis. The root cause was attributed to vibration, which is suspected to have occurred during use of a tube-sheet spray intended for on-line cleaning. This spray creates thermal shock on the inlet tube-sheet. The tube-sheet spray had been used quite frequently in an attempt to lower the exchanger differential pressure. This activity has been discontinued due to its limited efficacy and its contribution to tube failures.

- The plant had to be taken off line during the third quarter due to problems associated with the LTHRU. On July 30th, a temperature transmitter on the outlet of a condensate/syngas cross exchanger began reading erratically causing syngas flow through the exchanger to be fully by-passed. When the reading returned to normal, the by-pass valve closed before the main inlet valve opened due to the size and speed of the actuators on the valves. This caused the system to overpressure, which led to the plant tripping off coal operations. Software changes were made to prevent both valves from being closed simultaneously during coal operation.

PRODUCT SYNGAS QUALITY: Product syngas quality remained consistent throughout 1998. Miller Creek coal had virtually no effect on the quality of the product syngas.

Hydrogen Content: Hydrogen content (dry weight-percent) in the syngas varied from an average monthly low of 32.71% in October and November to a high of 33.82% in August. Average concentration for hydrogen in the product syngas for 1998 was 33.35%

Carbon Dioxide Concentration: Carbon dioxide (dry weight-percent) in the syngas varied from an average monthly low of 14.92% in December to a high of 16.06% in April. Average concentration for carbon dioxide in the product syngas for 1998 was 15.62%.

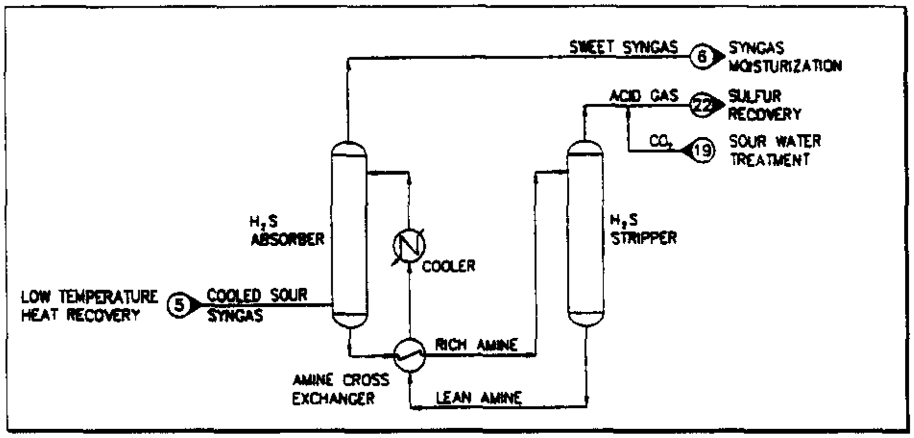
Carbon Monoxide Concentration: Carbon monoxide (dry weight-percent) in the syngas varied from an average monthly low of 44.25% in September to a high of 46.73% in December. Average concentration for carbon monoxide in the product syngas for 1998 was 45.54%.

Methane Content: Methane (dry weight-percent) in the syngas showed a slight variability throughout the year. A low value of 1.91% was recorded in September with a high of 2.29% being recorded in December. Average concentration for methane in the product syngas for 1998 was 2.06%.

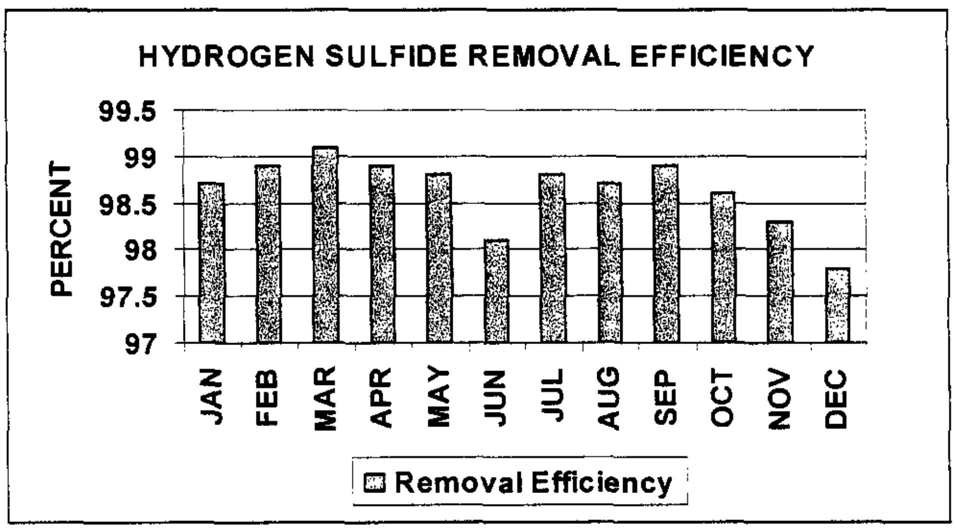
Hydrogen Sulfide Concentration: H_2S concentration (ppm) in the product syngas is a direct result of the operational characteristics of the Acid Gas Removal System. Variability can be directly attributable with system performance equipment difficulties in that system throughout the year. A high value of 107.24 ppm was recorded in June while a low value of 23.48 ppm was recorded in September. Average concentrations of hydrogen sulfide for 1998 was 75.24 ppm.

Carbonyl Sulfide Concentration: COS concentration (ppm) in the product syngas shows an expected low variability when compared to previous reporting periods. The COS hydrolysis unit operated more efficiently during 1998 when compared to previous years. COS in the product gas recorded an average high value of 36.63 ppm in June and an average low value of 9.03 ppm in March. The average value for COS in the product gas for 1998 was 26.78 ppm.

ACID GAS REMOVAL



The first step in the sulfur removal and recovery process is the Acid Gas Removal (AGR) system, which removes the hydrogen sulfide (H_2S) present in the sour syngas. The AGR system also produces a concentrated H_2S stream (acid gas) that is fed to the Sulfur Recovery Unit (SRU). The AGR system is a totally contained system and does not produce emissions to the atmosphere. H_2S is removed in the absorber using an H_2S solvent, methyldiethanol amine (MDEA). The H_2S rich solvent exits the absorber and flows to a reboiled stripper where the H_2S is steam stripped at low pressure. The concentrated H_2S stream exits the top of the stripper and flows to the SRU. The lean amine exits the bottom of the stripper and is cooled, then recycled to the absorber.



Hydrogen sulfide removal efficiencies remained fairly consistent throughout 1998 as can be seen by the chart at right. The efficiency calculation uses total combustion turbine stack and flare stack syngas emissions (as sulfur) compared to the total sulfur feed to the gasification plant (sulfur, dry-weight percent) for the most conservative estimate of performance.

The following significant events occurred during the 1998 operational campaign in the AGR system and are directly responsible for the minor variations seen in H_2S removal efficiency:

- Removal efficiency for the 1st quarter of 1998 decreased slightly compared to the last quarter of 1997 even though the plant processed an impressive 65% increase in syngas production. A vacuum distillation was performed on the acid gas absorbent (MDEA) to remove heat stable amine salts (HSAS), in the fourth quarter of 1997. The distillation significantly enhanced the removal efficiency of H_2S. Since then, low levels of contaminants, including HSAS, iron, and sodium, have collectively contributed to a decrease in removal efficiency. Additionally, campaign-extending strategies have been employed, which sacrifice removal efficiency in the short term but will allow the plant to run for a longer period at far below the product syngas total sulfur limit specified in the gas turbine's operating air permit.

- In June, removal efficiency of H_2S dropped to 98.1%. This small decrease can be attributed to a combination of factors. First, upon startup in June, there was a change in the gasifier coal feedstock to Miller Creek coal. This coal contains a higher weight percent sulfur. This created a greater load on the AGR system, leading to a slightly higher level of H_2S slippage from the removal system. Second, rising ambient air temperature in June increased the average amine solution temperature, which, in turn, decreased its stripping efficiency.

- In the third quarter, H_2S removal efficiency increased slightly above the second quarter average of 98.7%. This increase is significant in that the average amine temperature increased appreciably during the third quarter, which is typically detrimental to H_2S absorption. The ability to sustain removal efficiency in spite of rising amine solution temperature was accomplished by reducing the amine concentration. It has been found that by reducing the amine concentration, better stripping of the H_2S can be achieved. After talking with system consultants and amine manufacturers, this phenomenon appears to be unique to our process. However, further studies suggest that at lower amine concentrations, the solution's thermodynamic properties become closer to those of water. Specifically, the heat capacity of the amine solution increases appreciably. Therefore, for a given amount of energy released into the amine solution, the temperature change is less for lower amine concentrations. Furthermore, the absorption of H_2S and CO_2 (which is also stripped in the column) by the amine solution is an exothermic reaction. Since the amine is more selective toward H_2S than CO_2 at lower temperatures, lower amine concentrations lead to increased H_2S removal efficiencies.

- The removal efficiency for the fourth quarter decreased slightly from the third quarter average of 98.8%. Throughout the fourth quarter, operations employed strategies, which sacrificed H_2S removal efficiency in exchange for greater plant efficiency, increased availability, and cost reduction. Although there are other contributing factors, such as amine concentration and temperature, H_2S removal efficiency is chiefly a result of amine circulation rate. Higher amine circulation rates lead to more H_2S being stripped from the syngas. However, this has an overall negative impact on efficiency because the higher amine circulation rates linearly increased the HSAS formation rate. HSAS loading of the MDEA negatively effects removal efficiency and the removal of the salts and/or replacement of the amine solution have negative cost impacts on the operation of the facility.

HSAS forms when non-volatile acids react with amine irreversibly, meaning they are not stripped under the vapor heating in the stripping column. Typical HSAS compounds include formates, sulfates, thiocyanates, acetates, and oxalates. These salts accumulate within the amine over time, continually tying up (or binding) free amine thus the term "bound amine". Bound amine is not free to remove H_2S from the syngas and is typically corrosive to system components as the heat stable salts level increases.

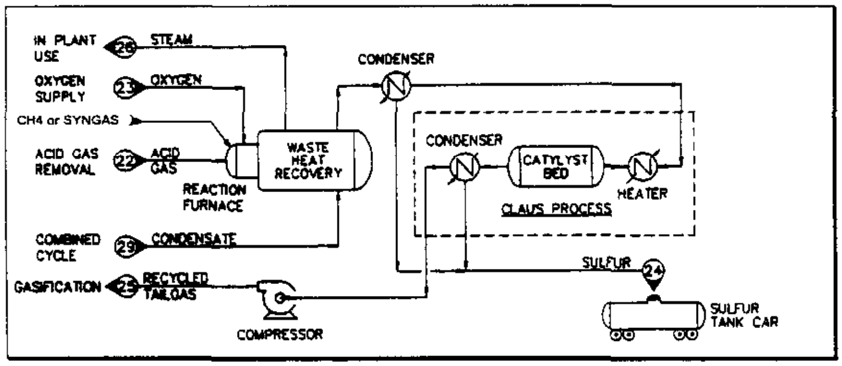
Ion Separation (ISEP) is designed to process approximately one (1) percent of the total MDEA flow in the system and remove HSAS so that column performance can be maintained. ISEP can be defined as reversible exchange of ions between a solid and a liquid in which no substantial change in the solid's structure occurs. The following represent key operational characteristics and improvement projects developed for the ISEP unit in 1998:

- Throughout the first quarter of 1998 the ISEP unit salts removal rate increased by 40%. Towards the end of the first quarter, the rate of salts removal was approaching the rate of formation within the AGR. This increase in performance can be attributed to several events. In the early part of the first quarter the ISEP resin was replaced due to suspected resin fouling. Additionally, operational fine-tuning occurred, which yielded the immediate result of an approximate 20% increase in removal. Finally, as the salt concentration rises, the absorption reaction equilibrium is driven forward, increasing removal efficiency.

- In the second quarter, progress in the ISEP unit operation experienced setbacks. The canisters containing the ion exchange resin started experiencing reliability problems. It appeared that the resin canisters were being chemically attacked by the combination of chemicals used within the unit. A test canister, constructed of an alternate material, was placed in service for an evaluation period. Also, test coupons were installed to determine the chemical resistance of other potential alternative materials.

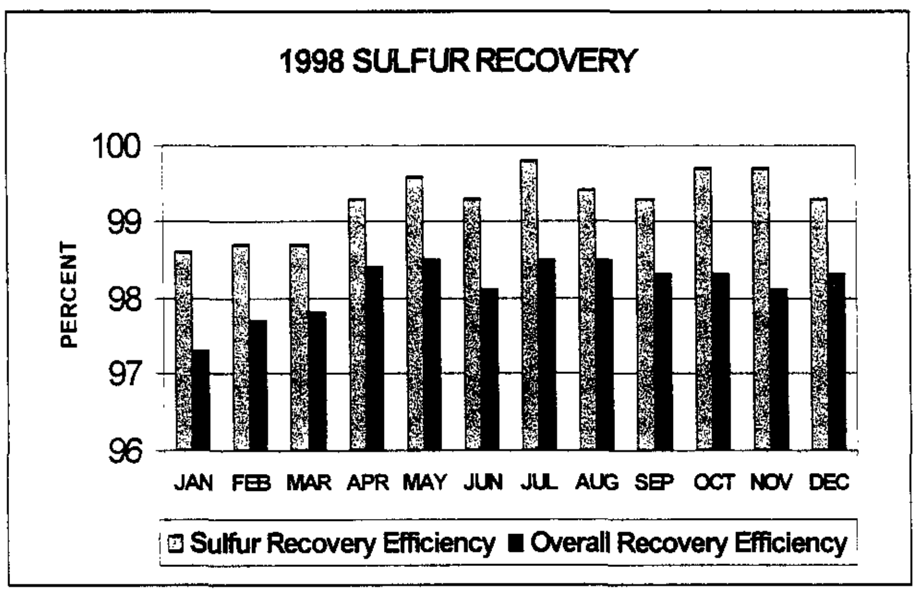
- The fourth quarter, plans for an expansion of the ISEP unit were developed. The planned expansion includes increasing the canister height to increase capacity and changing the material of construction from fiberglass to a metal alloy for increased mechanical integrity.

SULFUR RECOVERY



The concentrated H_2S stream from the acid gas removal system, and the CO_2 and H_2S stripped from the sour process water, are fed to a series of catalytic reaction stages where the H_2S is converted to elemental sulfur. The sulfur is recovered as a molten liquid and sold as a by-product. A tailgas stream, composed of mostly CO_2 and N_2 with trace amounts of H_2S, exits the last catalytic stage.

The tail gas from the Sulfur Recovery Unit (SRU) is hydrogenated to convert all the sulfur species to H_2S, cooled, compressed and then directed to the gasifier. This allows for a very high sulfur removal efficiency with minimal recycle requirements. Provisions in the system will allow for final treatment of the tail gas in the tail gas incinerator. A tank vent stream is also treated in the incinerator. The tank vent stream is composed of air purged through various in-process storage tanks and contains very small amounts of acid gases. The high temperature incinerator efficiently destroys the H_2S remaining in the stream by converting it to SO_2 before the exhaust gas is vented to the atmosphere from a permitted air emissions source.



Sulfur recovery efficiencies indicated at left are split into two specific areas. The blue columns indicate the efficiency of the SRU by comparing total stack emissions with total sulfur feed to the SRU. *Overall Plant removal efficiencies* (green columns) compare total joint venture emissions (as sulfur) verses total sulfur feed to the gasifier.

Variations in SRU sulfur recovery efficiency throughout 1990 are explained as follows:

- The efficiency decline noted in the first quarter was due, in part, to dilution of the H_2S and SO_2 throughout the catalyst beds of the SRU. This dilution was the direct result of an increase in combustion by-products due to additional fuel feed to the Claus reaction furnace. This was done in an attempt to raise the furnace temperature to increase ammonia destruction. It was previously thought that ammonia was initiating a reaction, which produced iron sulfide that was responsible for plugging several lines in the SRU. However, little benefit was realized from the increase in the reaction furnace temperature and those efforts were terminated.

- January efficiencies were low due to a trip of PSI's auxiliary boiler causing a loss of medium pressure steam to the recovery unit. As a result, the acid gas pre-heater lost steam pressure, sending cooler acid gas to the Claus reaction furnace. This, in turn, caused the reaction furnace to cool and prevented it from maintaining the proper concentrations necessary for the catalyst beds.

- Sulfur recovery efficiencies increased significantly in the second quarter from 98.8% to 99.4%. This is chiefly due to the use of two recycle compressors. In the past, questionable compressor reliability has prevented operations from running both machines. One machine was kept off line for use as a backup in the event of a primary compressor failure. With the improved reliability of these compressors, operations became more comfortable running both machines, which allows for more tail gas to be recycled and less directed to the tail gas incineration furnace.

Also contributing to greater sulfur removal efficiency in the second quarter was the decision to reduce the operating temperature of the Claus reaction furnace. The benefits of this are two fold. First, there is the obvious economic gain of using less fuel. Second, less fuel combusted in the reaction furnace decreases the amount of dilution of the H_2S and SO_2. Since the Claus catalyst beds are seeing higher concentrations of these two compounds, equilibrium dictates that the reaction will be shifted towards products. This means that a greater amount of sulfur entering the SRU will be recovered. Feeding less fuel to the reaction furnace should additionally increase the life of the Claus catalyst. During the June outage, the first catalyst bed was replaced with fresh catalyst. Laboratory results indicated that the catalyst had experienced a 40-50% deactivation. Analysis of the catalyst revealed that coking, or coating of the catalyst surface with hydrocarbon combustion products primarily caused the deactivation.

As a result of the above changes, sulfur recovery efficiency remained high during the third quarter. However, for the greater part of the third quarter, problems in the tail gas quench column have created pressure problems within the sulfur recovery unit. Operations compensated for theses problems by running two recycle compressors. Efforts to reduce the amount of supplemental fuel continued in the third quarter with success. Between the second and third quarters there has been a 30% reduction in the supplemental fuel required to fire the Claus reaction furnace.

The recovery efficiencies presented for December indicate a significant decrease. However, the facility started an extended outage on December 4th, which created elevated emissions associated with shutdown decontamination. This, in conjunction with a relatively small amount of sulfur feed for the month, yielded an atypical removal efficiency. Fourth quarter overall recovery efficiency is down slightly from the third quarter average of 98.3%.

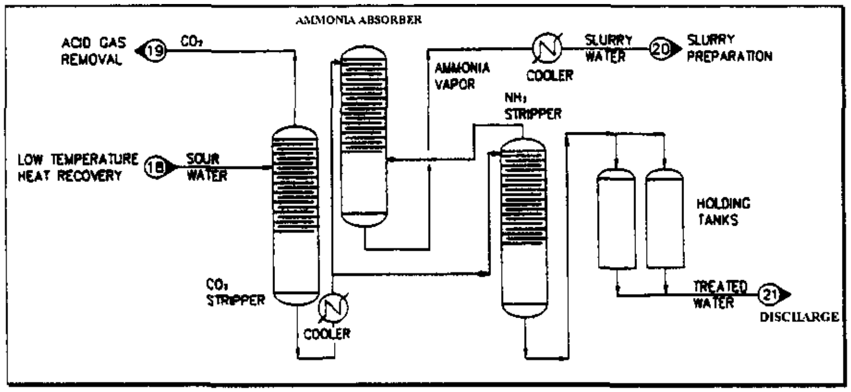
Several noteworthy projects were implemented in 1998 in the sulfur recovery area of the facility. The following outlines those projects and their effect on overall operation:

- One project in the first quarter was intended to lower O&M costs and reduce the risk of exposing operators to molten sulfur. The seal leg for the first sulfur condenser has been modified to facilitate removal of material causing flow restrictions. Presently in the evaluation period, the new design allows for removal of the material collecting in the bottom of the seal leg without cutting apart the seal leg. Seal leg drain modifications have also been made which will reduce the potential to expose operators to liquid sulfur.

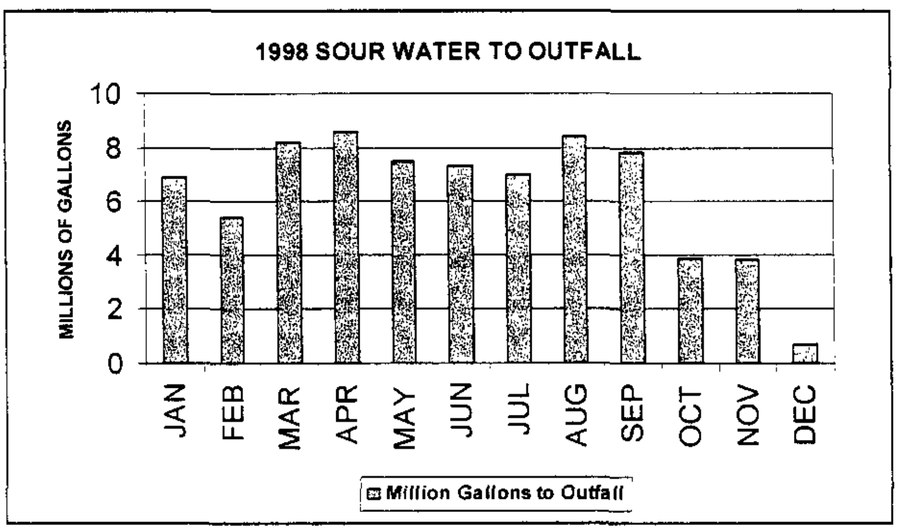
- Another project, implemented in the second quarter, is intended to improve safety and increase compressor reliability. The seal legs off of the first stage suction drums on the tail gas recycle compressors continuously over-pressure, allowing tail gas to escape into a sump where it was recovered by the tank vent system. To prevent the seal legs from over-pressuring, they were routinely blocked-in requiring operations personnel to manually de-inventory the condensed liquid in the suction drum. Occasionally, the unit would go unchecked until a high liquid level would trip the compressor. During the June outage, the seal legs were extended to prevent over-pressuring, thus reducing operator exposure to tail gas and increasing compressor reliability.

- A maintenance project of significant importance occurred during the outage in early September. Because of a hydrogenation by-pass valve leak, sulfur dioxide was allowed to react with the H_2S in the tail gas quench column, forming elemental sulfur. This sulfur plugged the column, heat exchanger, and filters within the quench loop. Once the by-pass valve was repaired, the entire quench loop was flushed with a 25% caustic solution, which was heated to 150 °F. The flush was successful and there has been no more evidence of sulfur formation within the column.

SOUR WATER TREATMENT

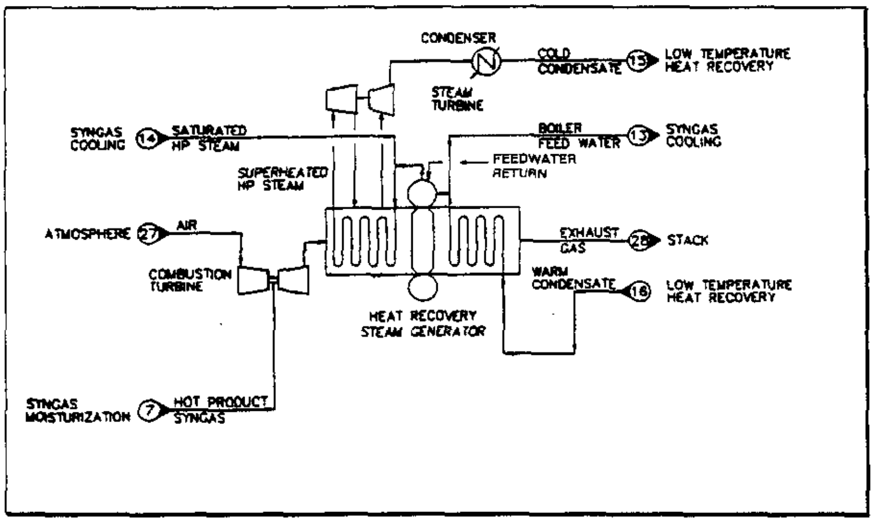


Water condensed during cooling of the "sour" syngas contains small amounts of dissolved gases, i.e. carbon dioxide (CO_2), ammonia (NH_3), hydrogen sulfide (H_2S), and trace contaminants. The gases are stripped out of the sour water in a two step process. First the CO_2 and the bulk of the H_2S are removed in the CO_2 stripper column by steam stripping. The stripped CO_2 and H_2S are directed to the SRU. The water exits the bottom of the column, is cooled, and a major portion is recycled to slurry preparation. Any excess water is treated in the ammonia stripper column to remove the ammonia and remaining trace components. The stripped ammonia is combined with the recycled slurry water. The treated water can be directed to the moisturizer or discharged from the plant. Prior to discharge, the water passes through two activated carbon filters for further processing. If out of specification for discharge, the treated water can be stored in holding tanks for further testing or recycle to the sour water system. Discharge of this water stream is controlled or regulated as a combined stream with PSI's plant discharge into the permitted water outfall pond.



As depicted at left, sour water to the outfall varied from a high in April of 8.6 million gallons to a low in December (a plant shutdown month) of 0.7 million gallons. In the second quarter, a significant amount of work was done on the carbon beds. High differential pressures across the beds caused damage to the vessel internals. During the June outage, structural modifications were made to ensure the vessel could withstand the higher differential pressures. Specific information about the quality of the water to the outfall is covered under the 1998 Environmental Monitoring Plan Annual Report and can be used as an additional reference to provide more specific information about discharge quality.

COMBINED CYCLE POWER GENERATION



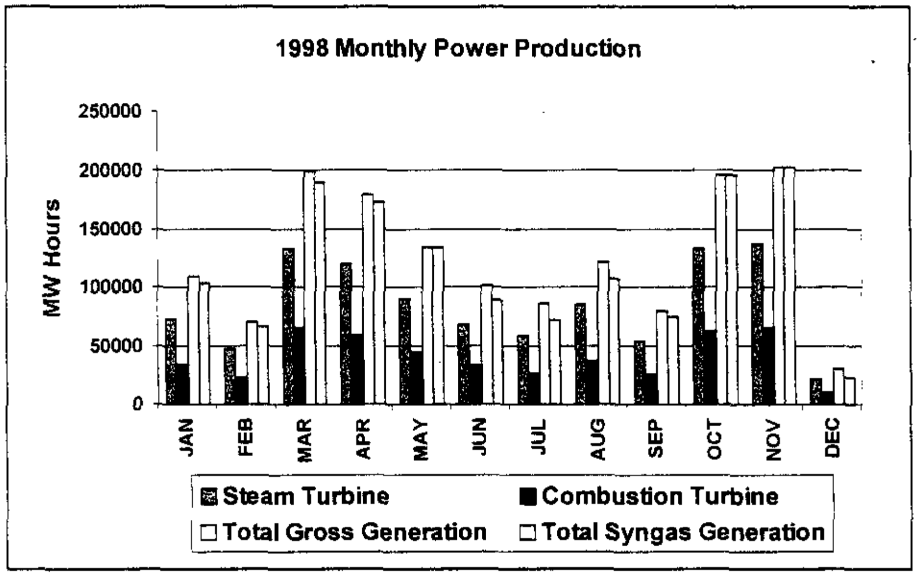
The combined cycle system consists of a combustion turbine generator, heat recovery steam generator (HRSG), reheat steam turbine generator, condenser, deaerator, flash drums, condensate pumps and boiler feedwater pumps.

The gas turbine (GT) is a nominal 192 MW advanced cycle combustion turbine fueled primarily by syngas. Fuel moisturization and steam injection controls NOx emissions and increases power output. Combustion air is drawn through inlet filters from outside the building housing the gas turbine. Combustion exhaust gases are routed to the HRSG. No. 2 fuel oil is used as back-up fuel for the gas turbine during startup and shutdown, and for other periods when syngas is unavailable. Fuel oil is stored in tanks located within the existing plant.

The HRSG recovers heat from the GT exhaust gases to generate high-pressure steam. This steam, combined with steam from the syngas HTHRU, re-powers the Unit 1 reconfigured steam turbine. Steam generated in the HRSG is piped to and from the steam turbine through extensive piping additions. The HRSG receives GT exhaust gases and generates steam at 1600 psig and 1000 degrees F (main steam) and re-heats extraction steam from the steam turbine back to 1000 degrees F at about 750 psig extraction pressure (reheat steam). The HRSG is specifically designed for high operating efficiency and configured for horizontal flow through a series of vertical heat transfer modules. Design of the HRSG is optimized for a syngas-fired gas turbine.

The Wabash River Station Unit 1 steam turbine is located in the existing powerhouse. The steam turbine was originally supplied by Westinghouse and went into commercial operation in 1953 at a nominal rating of 99 MW.

The turbine was designed for reheat operation with five levels of extraction steam used for feedwater heating. To maximize efficiency, feedwater is heated in both the HRSG and the gasification plant. With the need for extraction steam from the steam turbine eliminated, the steam previously extracted passes through the steam turbine to generate 105 MW of power. As a result, minor modifications to the turbine steam path ensure acceptable steam path velocities. The generator and main power transformer continue to be used and have required only minimal modification.



As can be seen by the chart at left, the fourth quarter of 1998 produced the largest total power output for the year. The months of October and November show a back-to-back high peak month operation, which has not been accomplished by the facility since beginning operation in 1995. With the exception of December (a plant outage month) the plant consistently produced in excess of 50,000 megawatt hours during 1998. Additionally, this was the first year where total megawatt hour production exceeded 1.4 million.

The following table illustrates production during 1998:

	1 QTR	2QTR	3QTR	4QTR	TOTAL
Combined Cycle Operating Hours On Syngas	**1,270**	**1,449**	**993**	**1,427**	**5,139**
Longest Continuous Run Hours On Syngas	**475**	**510**	**257**	**427**	
Maximum CT Output (MW)	**192**	**192**	**192**	**192**	
Maximum ST Output (MW)	**98**	**98**	**98**	**98**	
Total Gross Generation (MWHours) On Syngas	**359,689**	**395,683**	**254,000**	**420,188**	**1,429,560**

Budget Period 3 Activities

Budget Period 3 began on November 18, 1995. The costs shown reflect operational expenditures along with major process improvements implemented in 1998. Operations and systems data collected during the year will assist in the demonstration and commercialization of the technology.

	Revised Baseline Budget (per Cont. App. for Budget Period 3)	Actual Budget Period 3 Spending as of 12/31/98
Participant Share	$52,300,566	$64,032,578
DOE Share	$52,300,566	$48,898,439
Total	$104,601,132	$112,931,017

DOE Reporting and Deliverables

Spending and budget reports were submitted on both a monthly and quarterly basis according to the requirements of the Cooperative Agreement. Project reviews and Joint Venture quarterly reports were provided to the DOE. The following reporting requirements were submitted in accordance with Attachment C, sections 6 and 7 of the Cooperative Agreememt:

- Project Management Plan
- Environmental Monitoring Reports
- Operations Summary Reports

Other Activities

Several public relations and educational activities were carried out in 1998. Appendix C (Tab C) provides a list of selected public information and trade and technical papers presented by Dynegy or PSI personnel related to the WRCGRP.

In 1998, Gasification Services, Inc. received the Indiana State Governor's Award for Excellence in Recycling. The award was presented to only two manufacturing facilities out of 109 nominated. The award was presented to the plant for its continuing work in SO_2 emission reductions (along with the recovery of sulfur and its use as a viable by-product), water recycling efforts, metal and waste recycling, and donating recyclable materials to charitable and civic organizations during 1997.

1999 ACTIVITIES AND MILESTONES

Activities in 1999 will focus primarily on continued evaluation of new project installations and renewed focus on proper gasifier operations. Major activities for 1999 will include the following:

- Evaluation of the Dry Char system element metallurgy/materials of construction.
- Continue to evaluate gasifier temperature control to aid in prevention of ash deposition.
- Achieve an increasingly effective understanding of the system and subsystem operating characteristics.
- Maintain/improve the expected dispatch orders in the Cinergy system.
- Fulfill the provisions of the Environmental Monitoring Plan.
- Obtain the data base and experience-base necessary to advance and meet the commercial markets for the technology.

Other Activities

Other activities of significance include meeting the DOE review and reporting requirements and further development of effective operations and maintenance programs. During 1999 community relations and education programs will be continued.

APPENDIX A

Glossary of Acronyms

Appendix A
Glossary of Acronyms

CAAA	-	**Clean Air Act Admendments**
CCT	-	**Clean Coal Technology**
CGCC	-	**Coal Gasification Combined Cycle**
COS	-	**Carbonyl Sulfide**
DOE	-	**Department of Energy**
EPA	-	**Environmental Protection Agency**
HHV	-	**Higher Heating Value**
HRSG	-	**Heat Recovery Steam Generator**
IDEM	-	**Indiana Department of Environmental Management**
ISEP	-	**Ion Separation unit**
LGTI	-	**Louisiana Gasification Technology, Inc.**
NEPA	-	**National Environmental Policy Act**
NPDES	-	**National Pollutant Discharge Elimination System**
P&ID	-	**Piping and Instrument Drawings**
PMP	-	**Project Management Plan**
PON	-	**Program Opportunity Notice**
WRCGRP	-	**Wabash River Coal Gasification Repowering Project**

APPENDIX B

List of Figures

Appendix B
List of Figures

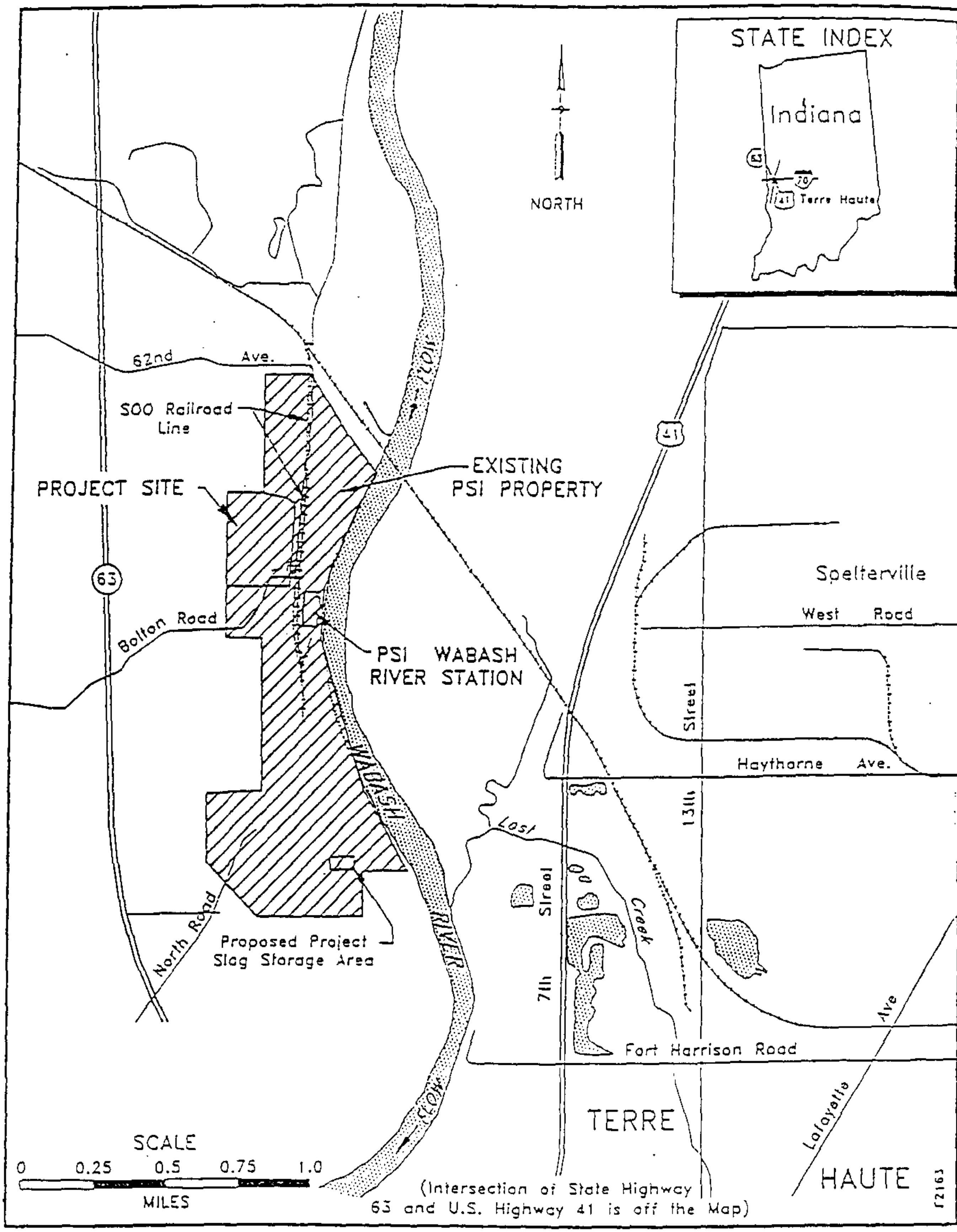


Figure 1 General Location Map Showing the Site of the Project

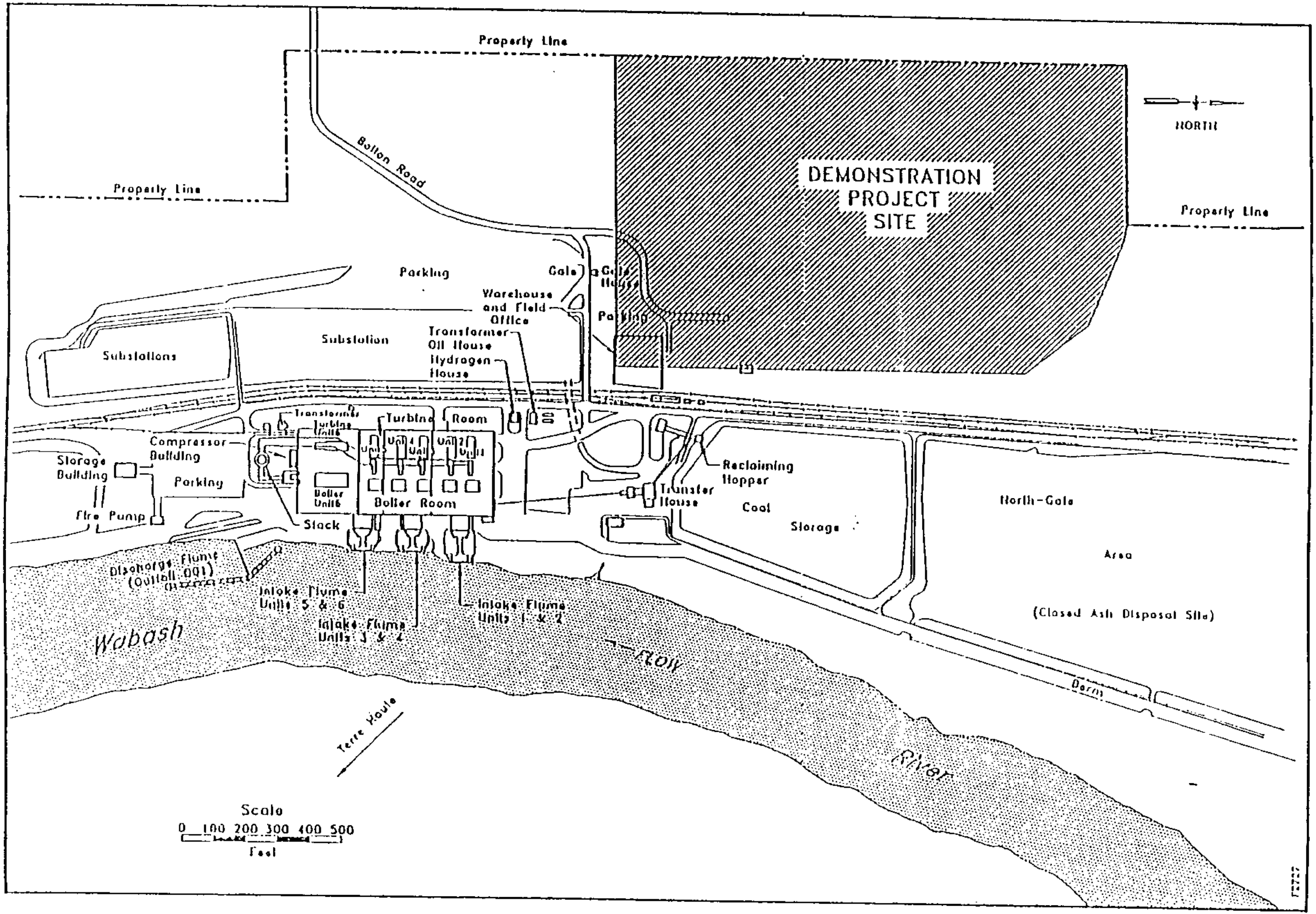


Figure 2 Site Map of the Wabash River Generating Station

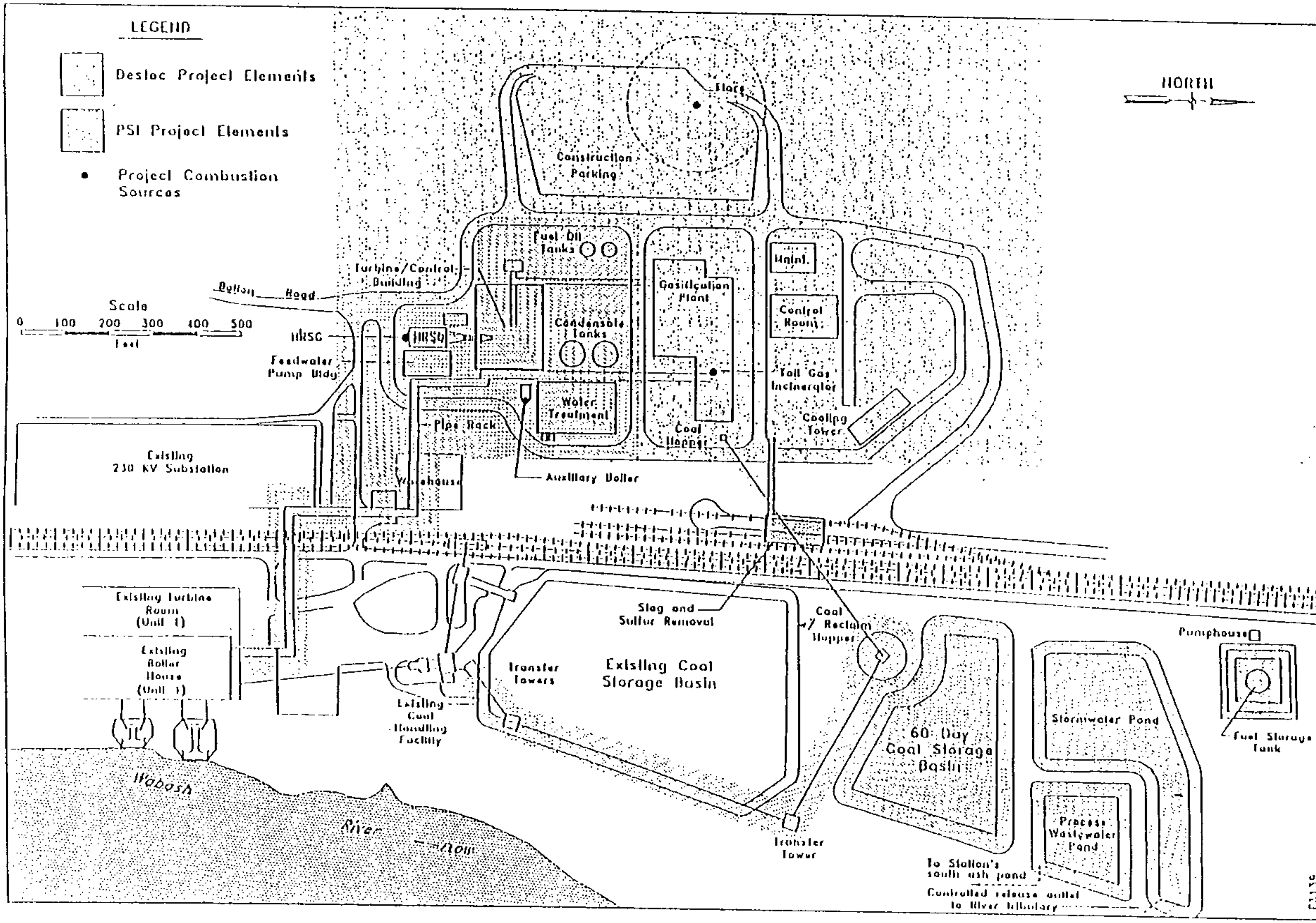


Figure 3 Project Plot Plan

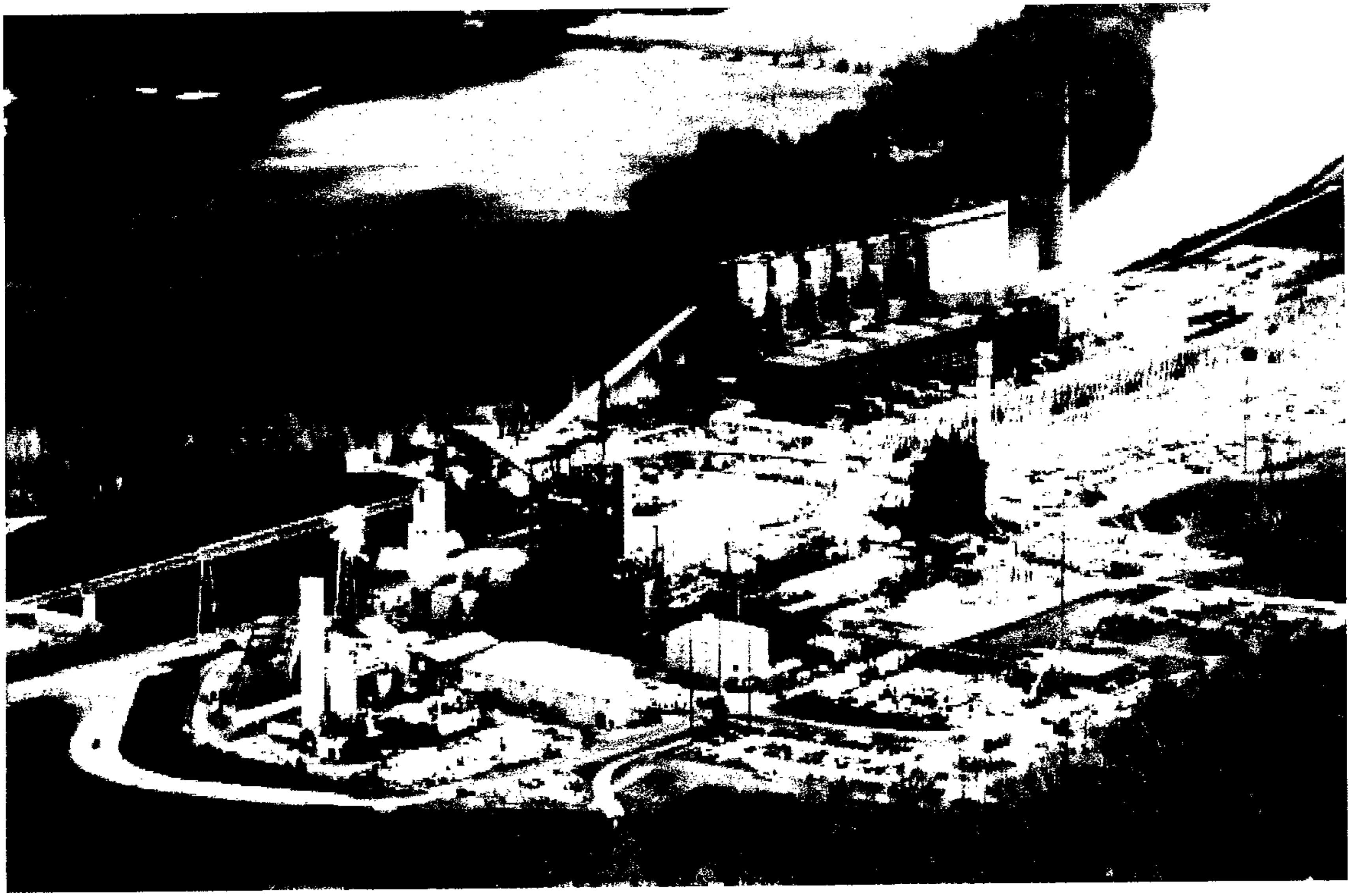


Figure 4

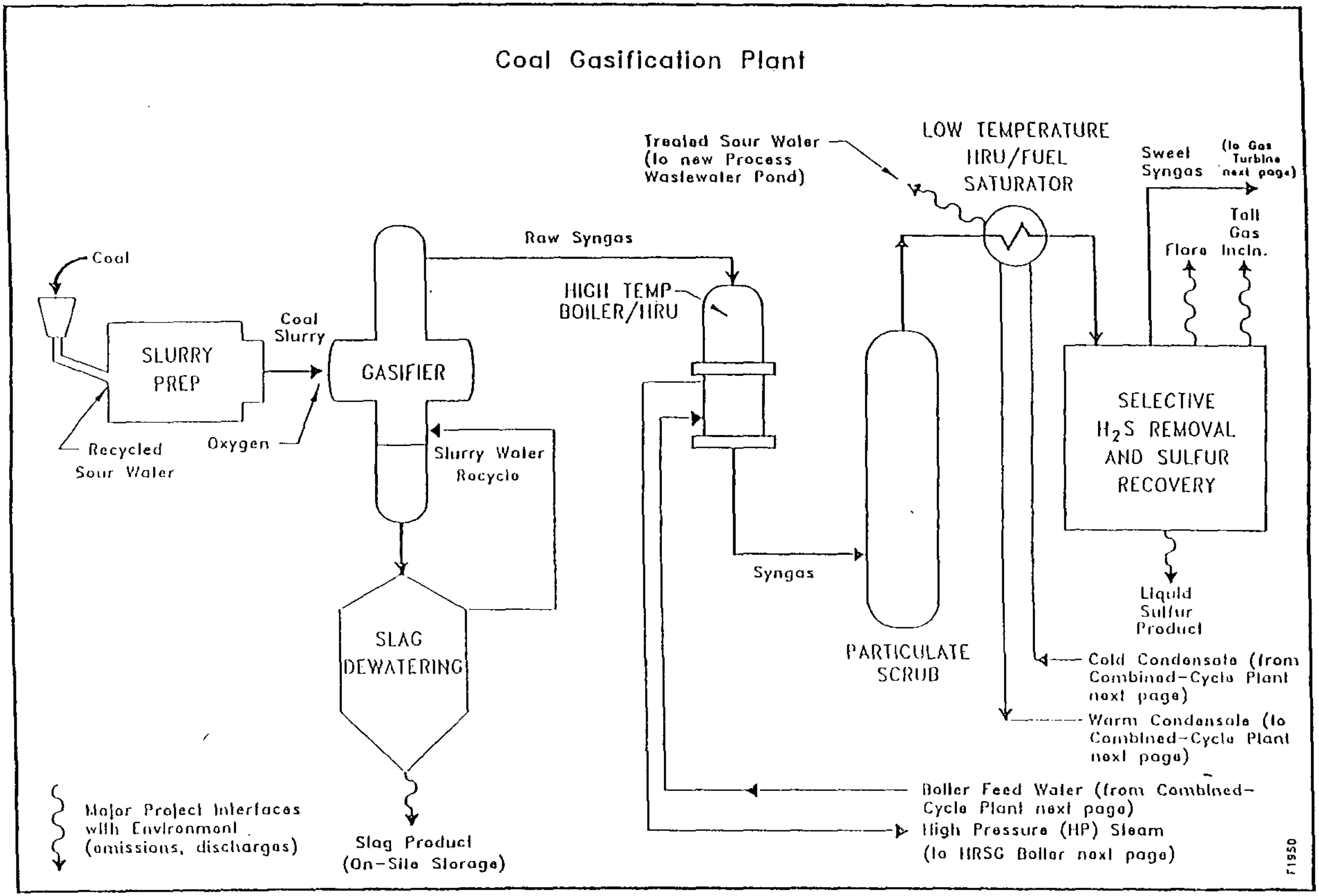


Figure 5 Conceptual CGCC Process Schematic

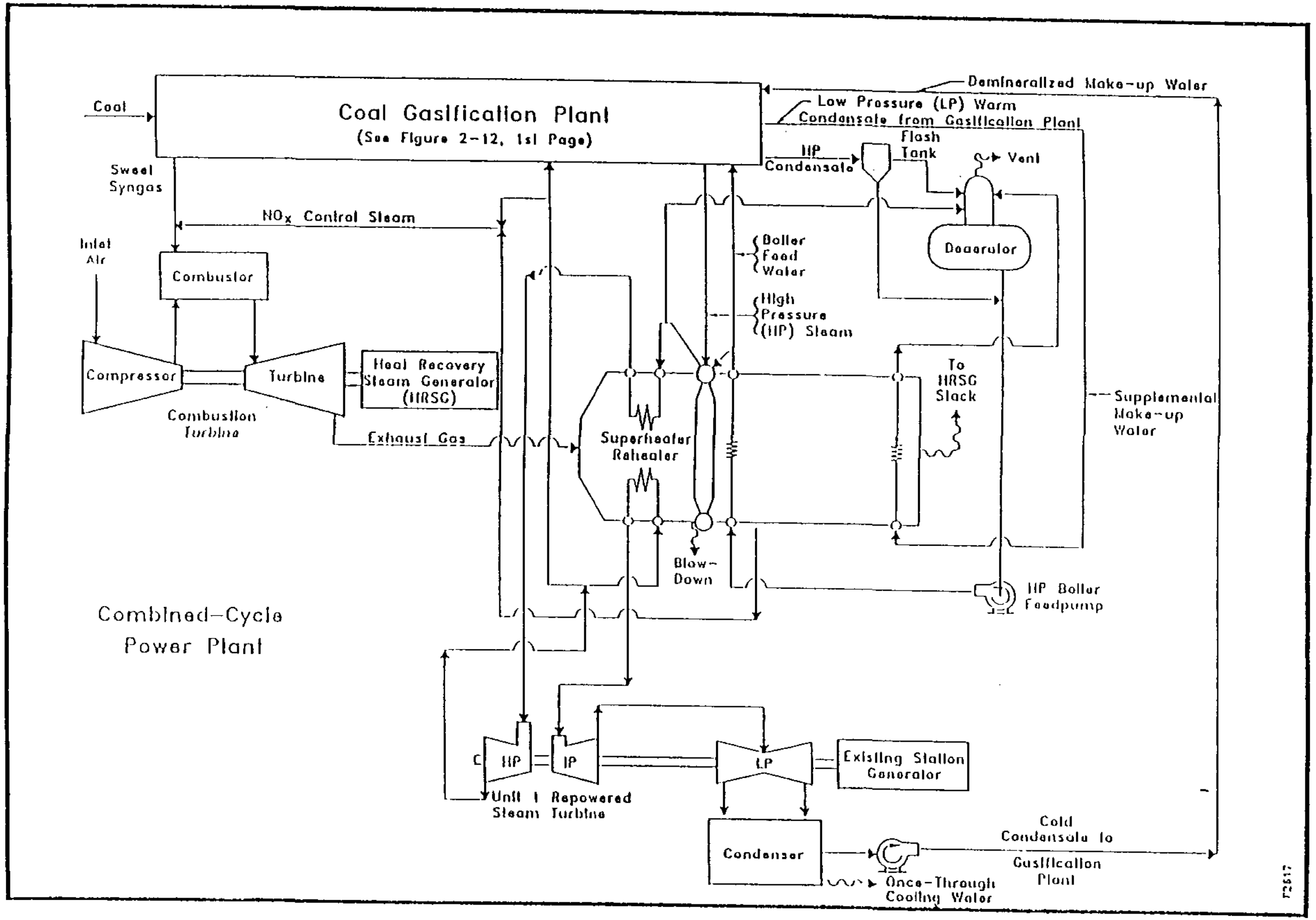


Figure 5A (Continued)

Block Flow Diagram

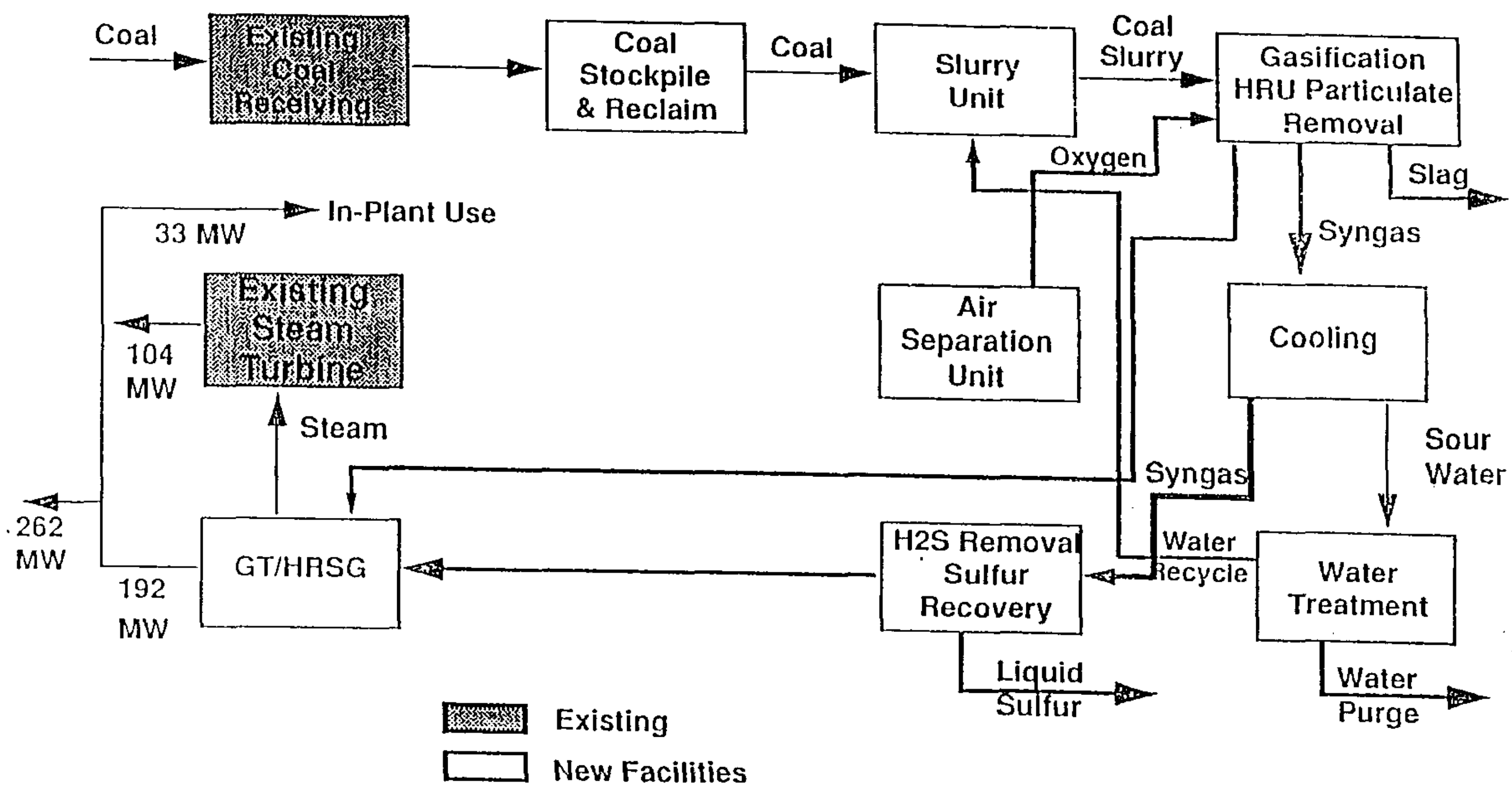


Figure 6

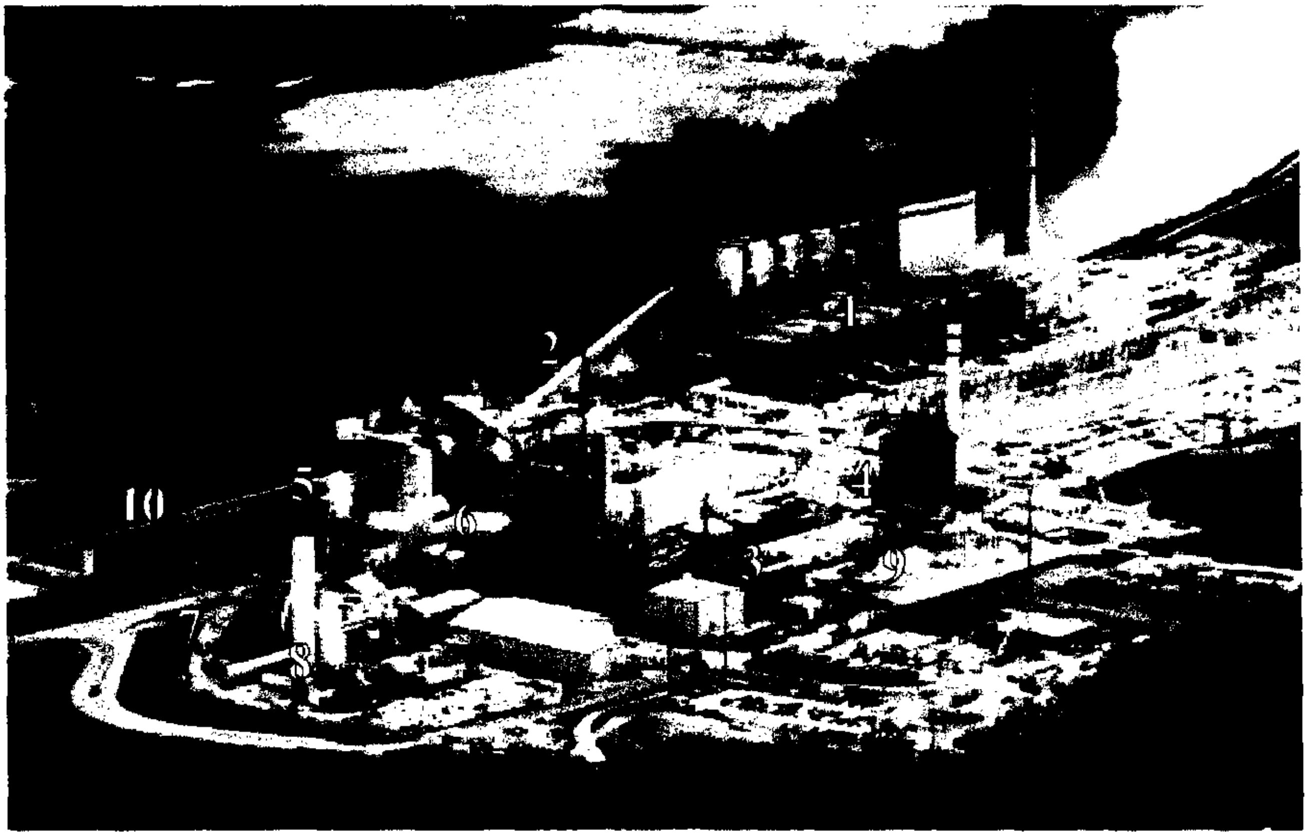


Figure 7

1. Existing Wabash Station
2. Existing coal transfer tower
3. Gas turbine building
4. Heat recovery steam generator
5. Coal receiving silo
6. Gasifier
7. Cooling Tower
8. Oxygen plant
9. New substation
10. Existing coal pile

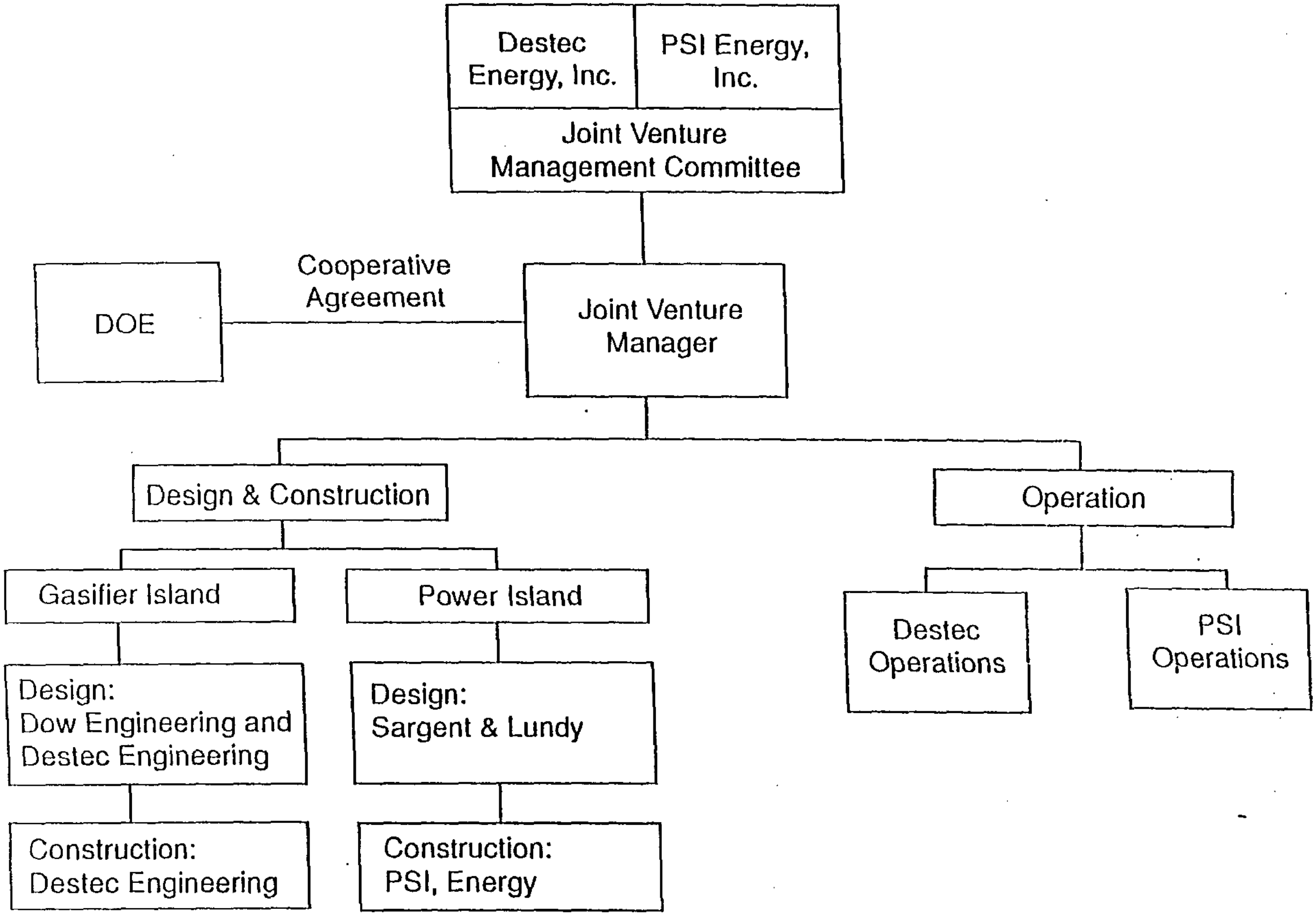


Figure 8 Project Organization

WABASH RIVER COAL GASIFICATION REPOWERING PROJECT

LIST OF PROJECT MILESTONES

Sept. 1998

WBS	MILESTONE	Nov. 1992 Proj. Mgmt. Plan **Original Baseline**	Nov. 1993 Proj. Eval. Plan **Revised Baseline**	June 2, 1995 Contin. Appl'n **Revised Baseline**	May 1996 Proj. Mgmt. Plan **Current Baseline**	**Completion Date**
1.1.04	Signing of Gasification Services Agreement	06/24/92	06/24/92	06/24/92	06/24/92	06/24/92
1.1.05	Completion of Funding	03/15/92	11/19/92	11/19/92	11/19/92	11/19/92
1.1.06	Receipt of Air Permits	03/01/93	05/28/93	05/27/93	05/27/93	05/27/93
	Receipt of NPDES Permit Modifications	12/01/92	12/01/92	12/06/93	12/06/93	12/06/93
1.1.07	NEPA Completion	10/01/92	05/28/93	05/28/93	05/28/93	05/28/93
1.1.08	Receipt of IURC Certificate of Need	03/01/93	05/26/93	05/26/93	05/26/93	05/26/93
1.1.10	Project Management					
	Project Management Plan	10/31/92	12/04/92	12/04/92	12/04/92	12/04/92
	Financing Plan & Licensing Agreements	02/28/93	04/30/93	04/30/93	04/30/93	04/30/93
	Project Definition & Preliminary Plant Design	02/28/93	03/15/93	03/15/93	03/15/93	03/15/93
	Continuation Application	02/28/93	05/05/93	05/28/93	05/28/93	05/28/93
	Formal Project Review	03/15/93	03/30/93	03/30/93	03/30/93	03/30/93
	Draft Environmental Monitoring Plan	04/30/93	03/31/93	03/31/93	03/31/93	03/31/93
1.1.13	DOE Award	07/27/92	07/27/92	07/27/92	07/27/92	07/27/92
1.1.30	Award of EPC Subcontract for Oxygen Plant	11/15/92	12/15/92	12/15/92	12/15/92	12/15/92
1.2.01	Project Management					
	Environmental Monitoring Plan	06/30/93	06/30/93	07/28/93	07/28/93	07/28/93
	40% Completion Formal Project Review	06/30/94	06/30/94	04/05/94	04/05/94	04/05/94
	90% Completion Formal Project Review	04/30/95	04/30/95	03/09/95	03/09/95	03/09/95
	Final Public Design Report	07/31/95	01/31/95	07/01/95	07/01/95	07/07/95
	Test Plan	05/25/95	05/25/95	07/01/95	07/01/95	07/08/95
	Plant Startup Plan	07/31/95	07/31/95	05/25/95	05/25/95	05/25/95

Figure 9

WABASH RIVER COAL GASIFICATION REPOWERING PROJECT

LIST OF PROJECT MILESTONES

Sept. 1998

WBS	MILESTONE	Nov. 1992 Proj. Mgmt. Plan Original Baseline	Nov. 1993 Proj. Eval. Plan Revised Baseline	June 2, 1995 Contin. Appl'n Revised Baseline	May 1996 Proj. Mgmt. Plan Current Baseline	Completion Date
	Continuation Application	07/31/95	01/31/95	06/02/95	06/02/95	06/02/95
1.2.04	Start of On-Site Dirtwork	12/01/92	06/01/93	06/01/93	06/01/93	06/01/93
	Release of Gasification Plant Site	09/01/93	09/10/93	09/17/93	09/17/93	09/17/93
1.2.05	Mobilization to Site	09/01/93	09/10/93	09/17/93	09/17/93	09/17/93
1.2.20	Award of High Temperature Heat Recovery Unit	11/01/92	11/03/92	11/03/92	11/03/92	11/03/92
	Award of Gasifier Vessels	01/10/93	01/21/93	01/21/93	01/21/93	01/21/93
	Jobsite Reciept of HTHRU	09/01/94	09/01/94	07/15/94	07/15/94	07/15/94
	Jobsite Reciept of Gasifier	07/01/94	07/01/94	05/15/94	05/15/94	05/15/94
1.2.22	Start of Foundation Work	09/15/93	10/08/93	10/08/93	10/08/93	10/08/93
	Setting of First Gasifier	09/01/94	09/01/94	06/08/94	06/08/94	06/08/94
	Setting of Second Gasifier	11/01/94	11/01/94	06/14/94	06/14/94	06/14/94
	Start of Refractory Installation	09/15/94	09/15/94	08/10/94	08/10/94	08/10/94
	Initial Firing with Coal	08/15/95	07/01/95	07/01/95	07/01/95	08/17/95
	Initial Delivery of Syngas	08/15/95	07/01/95	07/01/95	07/01/95	08/25/95
1.2.29	Completion of 100 Hour Test	10/01/95	08/15/95	08/15/95	11/18/95	11/18/95
1.2.30	Jobsite Receipt of Main Air Compressor	09/01/94	09/01/94	07/15/94	07/15/94	07/15/94
	Setting of Column	08/01/94	08/01/94	03/30/94	03/30/94	03/30/94
	Delivery of Oxygen	07/15/95	07/01/95	06/19/95	06/19/95	06/14/95
1.2.43	Construction Power/Water Available	09/01/93	10/06/93	10/20/93	10/20/93	10/20/93
1.2.50	Award of Coal Handling Subcontract	04/01/93	09/03/93	09/03/93	09/03/93	09/03/93
	Delivery of Coal to Syngas Facility	07/15/94	01/15/95	05/18/95	05/18/95	05/18/95
1.2.60	Award of STG Modification Subcontract	01/01/93	01/01/93	06/04/93	06/04/93	06/04/93

WABASH RIVER COAL GASIFICATION REPOWERING PROJECT

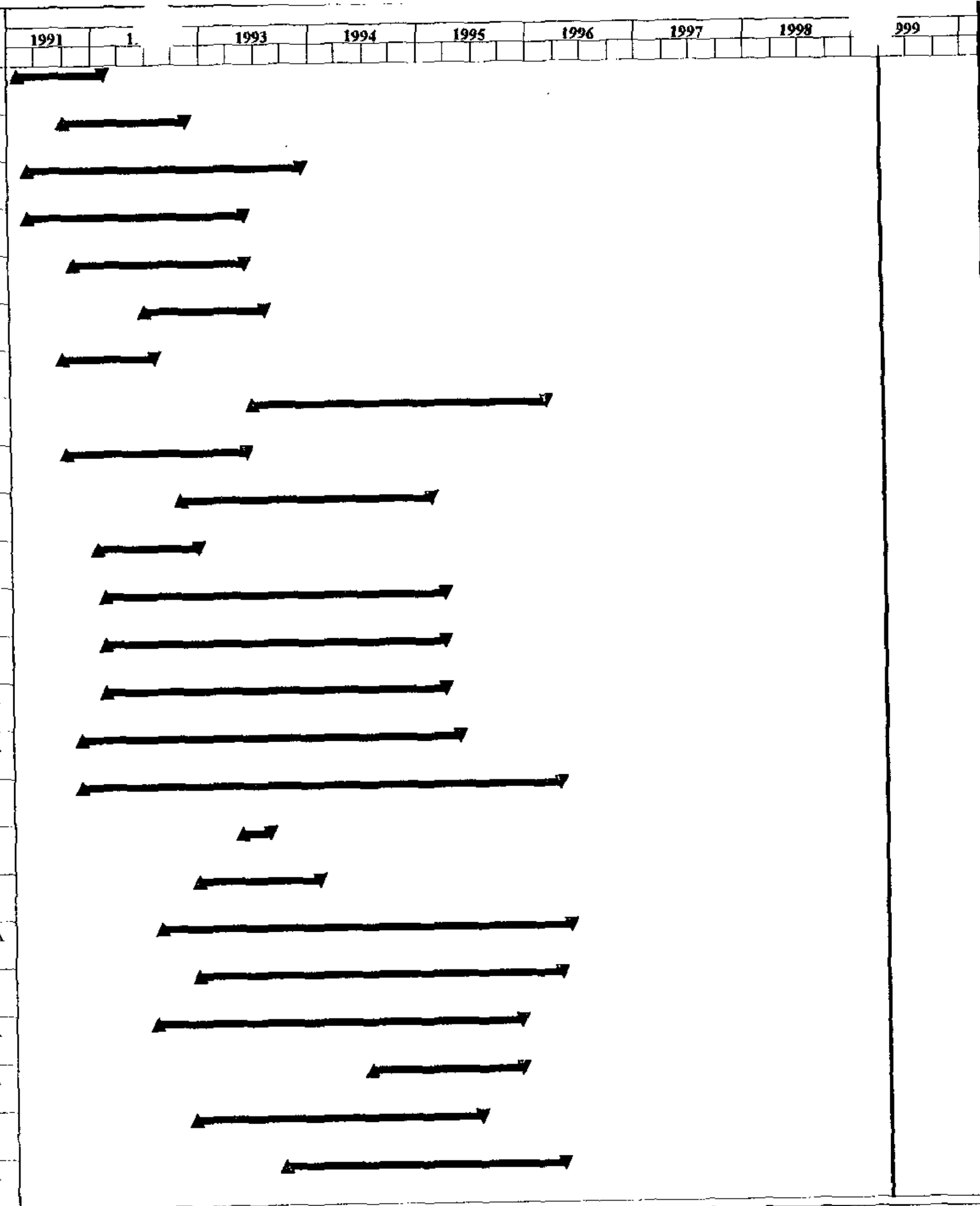
LIST OF PROJECT MILESTONES

Sept. 1998

WBS	MILESTONE	Nov. 1992 Proj. Mgmt. Plan **Original Baseline**	Nov. 1993 Proj. Eval. Plan **Revised Baseline**	June 2, 1995 Contin. Appl'n **Revised Baseline**	May 1996 Proj. Mgmt. Plan **Current Baseline**	**Completion Date**
1.2.70	Award of Gas Turbine Generator (GTG)	01/31/92	01/31/92	01/31/92	01/31/92	01/31/92
	Award of Heat Recovery Steam Generator (HRSG)	10/15/92	10/15/92	10/15/92	10/15/92	10/15/92
	Jobsite Delivery of GTG	03/01/94	01/01/94	03/18/94	03/18/94	03/18/94
1.2.75	Hydrotest of HRSG	04/15/95	04/15/95	03/31/95	03/31/95	03/31/95
	Synchronization of GTG	05/15/95	01/15/95	06/07/95	06/07/95	06/10/95
1.2.81	GTG Operation on Oil	01/01/95	01/01/95	06/07/95	06/07/95	06/09/95
	GTG Operation on Syngas	05/15/95	08/15/95	08/15/95	10/03/95	10/03/95
1.3.01	Project Management					
	Startup and Modification Report	12/01/95	12/01/95	11/01/95	01/01/99	
	Project Management Plan Update		not represented	11/01/95	05/01/96	05/16/96
	Formal Project Reviews	Annual				
	Draft Final Technical Report	07/31/98	07/31/98	09/30/98	01/01/99	
	Technology Performance & Economic Evaluation	11/30/98	11/30/98	10/01/98	02/01/99	
	Final Technical Report	12/31/98	12/31/98	11/30/98	02/28/99	

Figure 9

Activity ID	Activity Description	% Comp.	Early Start	Early Finish
1010	OVERALL PROJECT - SCOPE DEFINITION	100	01MAY91A	14FEB92A
1050	FINANCE/FUNDING	100	01OCT91A	15NOV92A
1060	PERMIT PREPARATION & SUBMITTAL	100	07JUN91A	06DEC93A
1070	NEPA PROCESS	100	07JUN91A	28MAY93A
1080	IURC APPROVAL	100	01NOV91A	26MAY93A
1100	PROJECT MANAGEMENT/ENVIRONMENTAL PLANS	100	19JUN92A	30JUL93A
1130	DOE COOPERATIVE AGREEMENT	100	16SEP91A	27JUL92A
1140	PROCESS CONSULTANTS & FEES	100	15JUN93A	29FEB96A
1200	GASIFICATION PLANT PROCESS DESIGN	100	01OCT91A	30MAY93A
1220	GASIFICATION PLANT AREA DESIGN	100	15OCT92A	01FEB95A
1300	OXYGEN PLANT PACKAGE DESIGN	100	10JAN92A	15DEC92A
1400	UTILITIES DESIGN	100	02FEB92A	15MAR95A
1500	COAL HANDLING DESIGN	100	01FEB92A	15MAR95A
1600	REPOWERING DESIGN	100	01FEB92A	15MAR95A
1700	GAS TURBINE AREA DESIGN	100	12NOV91A	01MAY95A
1900	POWER GENERATION PROJECT MGMT/COMMON ENGS	100	12NOV91A	01APR96A
2010	PROJECT MANAGEMENT PLAN	100	01MAY93A	30JUL93A
2040	SITE PREPARATION	100	01DEC92A	14JAN94A
2050	GASIFICATION PLANT CONST MANAGEMENT	100	01AUG92A	01MAY96A
2060	GAS TURBINE AREA CONSTRUCTION MANAGEMENT	100	01DEC92A	01APR96A
2150	GP PRE-OPERATIONS MANAGEMENT	100	12JUL92A	18NOV95A
2160	GT SELECTION & TRAINING PLANT OPERATORS	100	30JUN94A	18NOV95A
2200	GASIFICATION PLANT EQUIPMENT PROCUREMENT	100	15NOV92A	30JUN95A
2220	GASIFICATION PLANT CONSTRUCTION	100	13SEP93A	01APR96A



Project Start 01JUN91
Project Finish 01JUN99
Data Date 31MAR99
Run Date 11MAR99

Early Bar
Progress Bar
Critical Activity

6216

Sheet 1 of 2

DESTEC ENGINEERING, INC.
WABASH RIVER COAL GASIF REPOWER PROJ
DOE PROJECT PLAN

FIGURE. 10

Activity ID	Activity Description	% Comp.	Early Start	Early Finish
2290	GAS PLANT ACCEPTANCE TESTING	100	25OCT95A	18NOV95A
2300	OXYGEN PLANT PROCUREMENT & CONSTRUCTION	100	15DEC92A	17FEB96A
2430	UTILITIES CONSTRUCTION	100	14JUN93A	01DEC94A
2500	COAL HANDLING PROCUREMENT & CONSTRUCTION	100	03MAY93A	01APR96A
2600	REPOWERING PROCUREMENT & CONSTRUCTION	100	04JUN93A	01APR96A
2700	GT AREA EQUIPMENT PROCUREMENT	100	31JAN92A	30NOV94A
2750	GAS TURBINE AREA CONSTRUCTION	100	13SEP93A	01APR96A
2810	GAS TURBINE ACCEPTANCE TESTING	100	01JUN95A	01APR96A
2990	PLANT PERFORMANCE TESTING	100	11OCT95A	18NOV95A
3010	PROJECT MANAGEMENT PLAN UPDATE	100	01DEC95A	16MAY96A
3060	ENVIRONMENTAL REPORTING	95	01DEC95A	01JUN99
3130	WARRANTY ADMINISTRATION	100	01DEC95A	02DEC96A
3140	GP COMMERCIAL OPERATION - DEMONSTRATION PERIOD	95	01DEC95A	01JUN99
3240	GT COMMERCIAL OPERATION - DEMONSTRATION PERIOD	100	01DEC95A	02DEC96A
11301PD	PRE AWARD PERIOD	100	16SEP91A	01AUG92A
11311BP	1ST BUDGET PERIOD	100	01AUG92A	30JUN93A
20402BD	2ND BUDGET PERIOD	100	30JUN93A	30NOV95A
30403BD	3RD BUDGET PERIOD	95	01DEC95A	01JUN99
11312PD	PHASE I DESIGN	100	01AUG92A	01FEB95A
20403PD	PHASE II CONSTRUCTION	100	01DEC92A	30NOV95A
30514PD	PHASE III OPERATION	95	01DEC95A	01JUN99

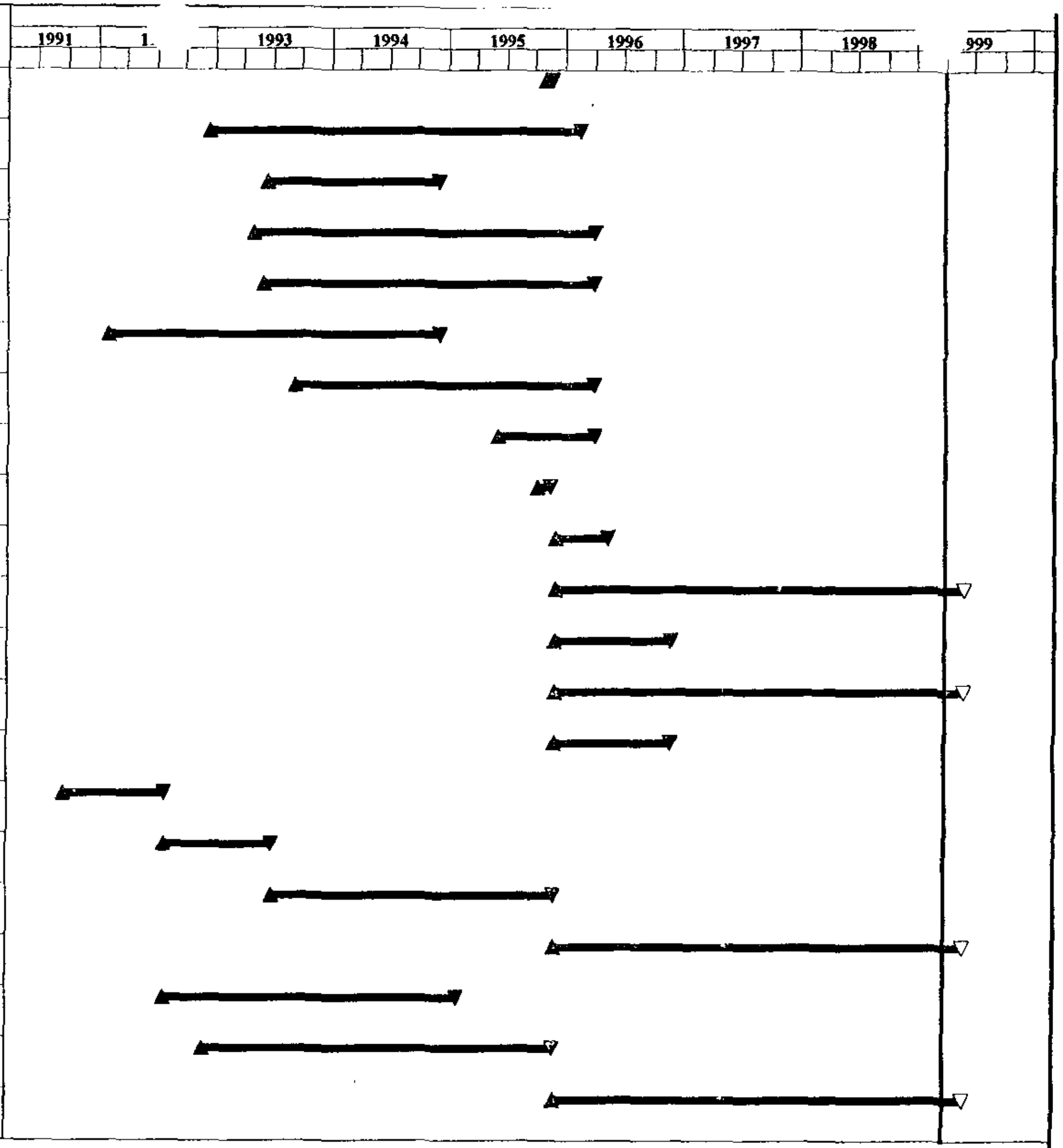


FIGURE 10

PLANT OPERATION STATISTICS
1998

GASIFICATION PLANT

PERFORMANCE DATA

Coal Gas Efficiency	73.89 %
Gasifier on Coal (Hours)	5,279
Gasification Plant Capacity Factor (Produced)	56.6 %
Gasification Plant Capacity Factor (Delivered)	55.0 %

PRODUCTION DATA

Syngas on Spec (MMBtu)	8,832,869
1600# Steam (Mlbs)	2,214,393
Sulfur (Mlbs)	24,902
Slag, Moisture Free (Mlbs)	70,228

DELIVERED PRODUCTION

Actual Syngas Delivered (MMBtu)	8,578,518
1600# Steam (Mlbs)	2,184,810

MATERIAL/ENERGY USED

Coal, Moisture Free (Tons)	490,741
Coal (MMBtu)	12,071,728
Intermediate Pressure Steam (Mlbs)	146,421
Electrical Power, Total (MWh)	268,792
Oxygen, (Tons)	442,322
Fuel Gas (Mlbs)	9,751

POWER PLANT

PERFORMANCE DATA

Combustion Turbine Operating Hours (Syngas)	5,139
Combustion Turbine Operating Hours (Total)	5,763
Steam Turbine Operating Hours	5,641

PRODUCTION DATA

Combustion Turbine Generator (MWH)	1,023,123
Steam Turbine Generator (MWH)	490,515

Figure 11

APPENDIX C

List of Technical and Trade Publications Concerning WRCGRP

Appendix C
LISTING OF TECHNICAL PUBLICATIONS
(PUBLIC INFORMATION)

DATE	TITLE/SOURCE	AUTHOR(S)
September 1998	"Alternate Fuel Testing at the Wabash River Coal Gasification Repowering Project" Dresden, Germany	Amick
September 1998	Gasification Panel Participation/Presentation Energy Performance for the Chemical and Pulp and Paper Industries Workshop Cincinnati, OH	Amick
October 1998	"The Third Year of Commercial Operation at Wabash River" 1998 Gasification Technologies Conference, San Francisco, CA	Lynch

APPENDIX D

Run Documentation and Production Graphs

Appendix D
Run Documentation and Production Graphs

1998 Run Documentation

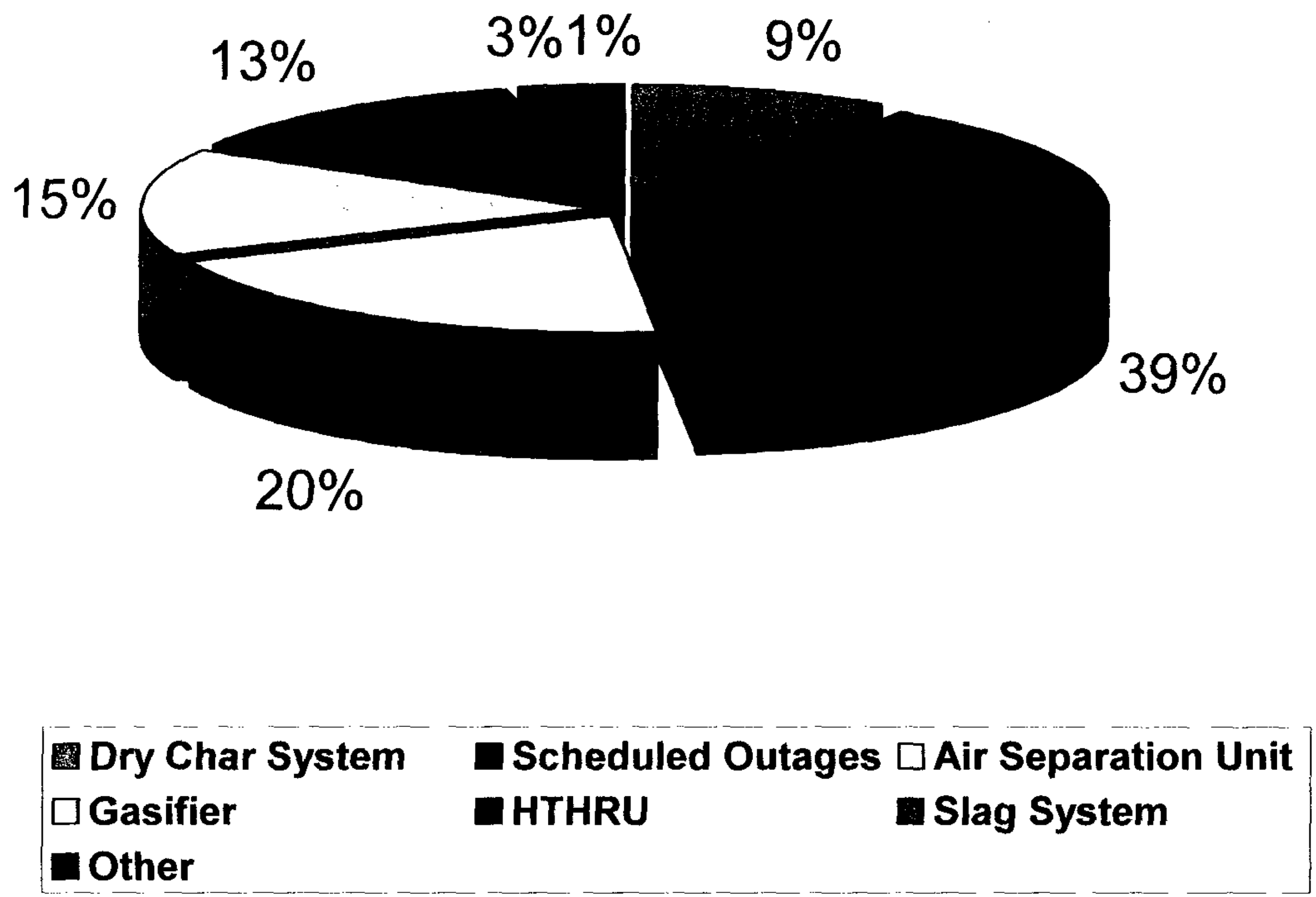
RUN	START	FINISH	DURATION (Hours)	REASON FOR TERMINATION
JAN98A	1/1/98 21:00	1/3/98 22:22	49.36	Manual trip due to failed M-120B, slurry mixer.
JAN098B	1/5/98 14:19	1/5/98 21:27	7.14	Gasifier trip on low O2:fuel ratio due to loss of Oxygen. Blown fuse on O2 vent valve in ASU.
JAN98C	1/6/98 02:45	1/8/98 19:48	65.05	Manual trip due to failed M-120A, slurry mixer.
JAN98D	1/10/98 04:30	1/10/98 07:01	2.52	Manual trip due to PSI's main syn-gas stop/ratio valve leaking.
JAN98E	1/10/98 15:53	1/11/98 20:57	29.07	Manual trip due to malfunction of main air compressor surge valve in the ASU preventing O2 delivery.
JAN98F	1/18/98 14:16	1/25/98 07:18	161.02	Gasifier Trip on O2:coal ratio due to malfunction of main air compressor guide vanes in the ASU preventing O2 delivery.
JAN98G	1/28/98 22:24	1/28/98 23:21	0.95	Gasifier trip on high oxygen to fuel ratio due to magmeter drifting low.
JAN98H	1/29/98 00:57	2/1/98 00:00	71.03	Continuing
FEB98A	2/1/98 00:00	2/4/98 02:39	74.65	Manual gasifier trip due to failed M-120B, slurry mixer.
FEB98B	2/5/98 04:52	2/5/98 22:36	17.73	Gasifier trip on O2:coal ratio due to 15KV power interruption and subsequent loss of main air compressor preventing O2 delivery.
FEB98C	2/7/98 07:22	2/13/98 21:18	157.93	Manual gasifier trip for first quarter 1998 scheduled maintenance.
MAR98A	3/1/98 10:12	3/2/98 10:21	24.14	Manual gasifier trip due to false knock out drum level and subsequent shutdown of the recycle syngas compressor.
MAR98B	3/2/98 13:45	3/5/98 15:38	73.88	Manual gasifier trip due to failed M-120A, slurry mixer.
MAR98C	3/7/98 03:40	3/27/98 02:40	479.00	Tripped gasifier on low boiler drum level.
MAR98D	3/27/98 04:28	3/27/98 08:00	3.53	Manual gasifier trip due to problems with the combustion turbine stop ratio valves.

RUN	START	FINISH	DURATION (Hours)	REASON FOR TERMINATION
MAR98E	3/27/98 14:00	4/1/98 00:00	106.00	Continuing
APR98A	4/1/98 00:00	4/2/98 14:46	38.75	Manual trip for scheduled replacement of slurry mixers M-120C and M-120D.
APR98B	4/3/98 10:03	4/11/98 22:08	204.08	Tripped off of coal operations due to loss of slurry flow from P-102. Slurry delivery shortage resulted in gasifier trip on HI-HI oxygen-to-coal ratio.
APR98C	4/12/98 14:30	4/13/98 07:25	16.92	Transferred off of coal operations due to CT trip caused by exciter breaker.
APR98D	4/13/98 15:59	4/28/98 09:32	353.55	Transferred off of coal operations for scheduled inspection of dry char ejectors, J-156A and J-156B.
APR98E	4/30/98 12:55	5/1/98 00:00	11.08	Continuing
MAY98A	5/1/98 00:00	5/21/98 23:09	503.15	Transferred off of coal operations due to char break through in V-155A.
JUN98A	6/10/98 13:06	6/10/98 17:23	4.28	Transferred off of coal operations due to high sulfur in product syngas during activation of new hydrogenation catalyst.
JUN98B	6/11/98 02:01	6/17/98 03:39	145.63	Transferred off of coal operations due to oil leak on inboard bearing of oxygen compressor, N-400.
JUN98C	6/19/98 15:48	6/19/98 16:55	1.12	Transferred off of coal operations due to blown rupture disks on slurry pumps P-110B and P-110C.
JUN98D	6/19/98 19:33	6/27/98 13:15	185.70	Transferred off of coal operations due to slag removal difficulties, gasifier taphole plugged.
JUL98A	7/20/98 08:48	7/28/98 22:09	205.35	Transferred off coal operation to change out dry char recycle ejector, J-156B.
JUL98B	7/29/98 01:09	7/30/98 18:22	41.22	Gasifier tripped on high pressure when a false temperature on a syngas exchanger, E-163 momentarily closed valves in the main syngas path.
JUL98C	7/30/98 22:10	8/1/98 00:00	25.83	Continuing
AUG98A	8/1/98 00:00	8/4/98 11:32	83.53	Gasifier tripped on O2:coal ratio when the oxygen compressor shutdown due to a loose power supply wire to a digital input card.

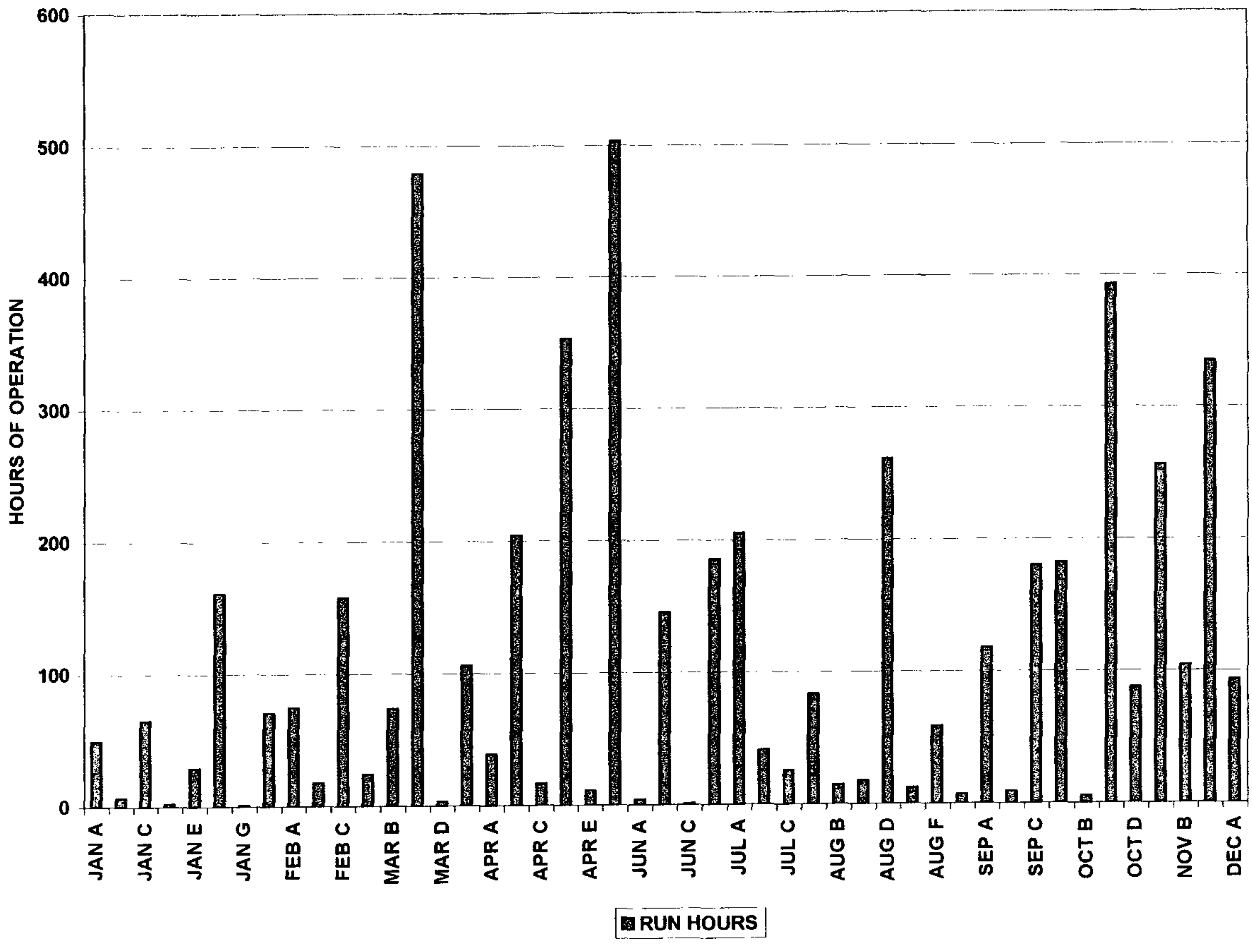
RUN	START	FINISH	DURATION (Hours)	REASON FOR TERMINATION
AUG98B	8/9/98 04:03	8/9/98 18:43	14.67	Gasifier tripped on O2:coal when the main air compressor shutdown due to a failed power supply to the guide vanes.
AUG98C	8/14/98 15:05	8/15/98 08:54	17.82	Gasifier tripped on O2:coal when a blown fuse on the 15KV potential transformer tripped both the oxygen and main air compressors in the ASU.
AUG98D	8/17/98 03:01	8/28/98 00:05	261.07	Transferred off coal operation to change out dry char recycle ejector, J-156B.
AUG98E	8/28/98 04:06	8/28/98 16:10	12.07	Transferred off coal operation to replace a failed dry char backpulse valve.
AUG98F	8/28/98 22:15	8/31/98 09:02	58.78	Transferred off coal to repair a sour water leak on the outlet of the chloride scrubbing column, C-165.
AUG98G	8/31/98 16:52	9/1/98 00:00	7.13	Continuing
SEP98A	9/1/98 00:00	9/5/98 21:56	117.93	Transferred off coal operation for third quarter scheduled maintenance outage.
SEP98B	9/22/98 03:18	9/22/98 12:28	9.17	Transferred off coal operation to repair syngas leak on the dry char vessel inlet flange.
SEP98C	9/23/98 12:04	10/1/98 00:00	179.94	Continuing
OCT98A	10/1/98 00:00	10/8/98 14:11	182.18	Gasifier tripped on loss of oxygen due to trip of the main air compressor when the power switch to the vibration protection equipment was accidentally turned off.
OCT98B	10/10/98 09:04	10/10/98 14:18	5.23	Transferred off coal operation to allow repair of the main water line coming to the combustion/steam turbine plant.
OCT98C	10/11/98 03:04	10/27/98 12:05	393.02	Transferred off coal operation to prevent hydrocarbon breakthrough on air separation unit mole sieve which failed to regenerate properly.
OCT98D	10/28/98 08:27	11/1/98 00:00	87.55	Continuing
NOV98A	11/1/98 00:00	11/11/98 16:01	256.02	Gasifier tripped on low steam drum level due to loss of boiler feed water.
NOV98B	11/12/98 14:57	11/16/98 23:15	104.30	Gasifier tripped on high oxygen to coal ratio when the suction of the slurry stuffing pumps plugged.

RUN	START	FINISH	DURATION (Hours)	REASON FOR TERMINATION
NOV98C	11/17/98 01:24	12/1/98 00:00	334.60	Continuing
DEC98A	12/1/98 00:00	12/4/98 21:11	93.2	Transferred off coal operations for fourth quarter scheduled maintenance outage.

1998 Downtime Analysis



OPERATIONAL RUN PERIODS FOR 1998



Monthly Plant Performance Data

	JAN	FEB	MAR	APR	MAY
PERFORMANCE DATA					
Coal Gas Efficiency	75.01	75.19	70.2	69.97	70.61
Gasifier on Coal (Hours)	386.21	250.32	686.48	624.42	503.17
PRODUCTION DATA					
Syngas on Spec (MMBtu)	640743	415197	1163287	1057500	823729
1600# Steam (Mlbs)	182479	105959	301501	265524	197757
Sulfur (Mlbs)	1724	1187	3303	2978	2271
Slag, Moisture Free (Tons)	5122	3333	9368	8535	6648
DELIVERED PRODUCTION					
Actual Syngas Delivered (MMBtu)	619052	405904	1128977	1028532	803478
1600# Steam (Mlbs)	164968	105428	301009	265134	197741
MATERIAL/ENERGY USED					
Coal, Moisture Free (Tons)	35794	23292	65454	59637	46446
Coal (MMBtu)	880539	572989	1610214	1467091	1142605
Intermediate Pressure Steam (Mlbs)	15042	9746	8173	17719	12651
Electrical Power, Total (MWh)	22244	20344	26022	25194	21232
Oxygen, (Tons)	33138	21125	59198	53277	40570
Fuel Gas (Mlbs)	2155	845	1149	498	302
PLANT EMISSION DATA					
Average Total Sulfur in Syngas (ppm)	87.54	79.21	75.98	87.17	100.6
Total SO2 Emissions (lbs)	96328	60666	161714	111780	85575
SO2, (Total Plant lbs/MMBtu of Coal Feed)	0.103	0.098	0.1	0.075	0.071
POWER PLANT PRODUCTION DATA					
Combustion Turbine Generator (MWh)	73935	47905	132768	120087	89708
Steam Turbine Generator (MWh)	35432	22691	66187	59214	44832
Total Gross Generation (MWh)	109367	70596	198955	179292	134540
Total Syngas Generation (MWh)	102870	67160	189659	172069	134495

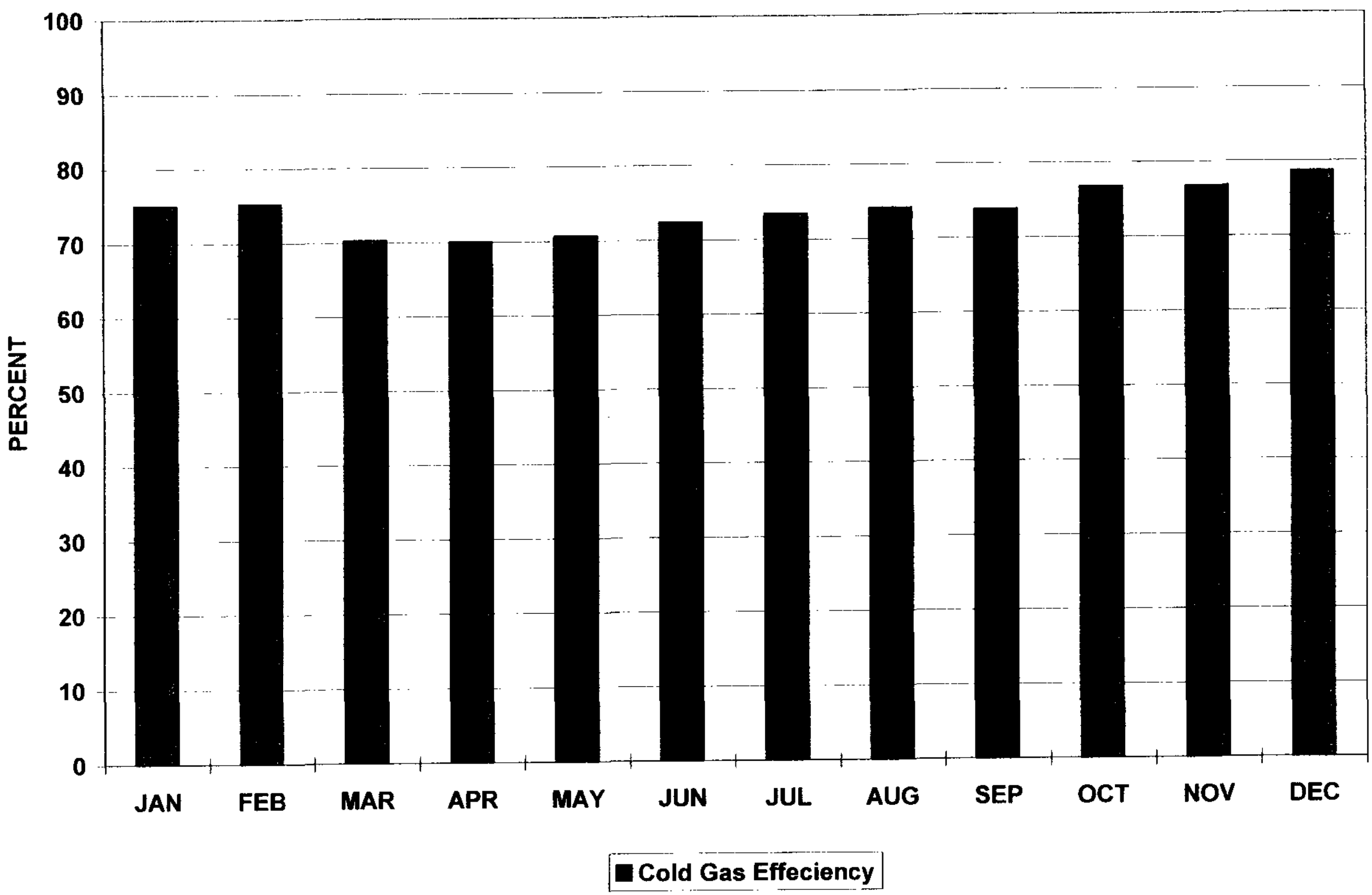
Monthly Plant Performance Data

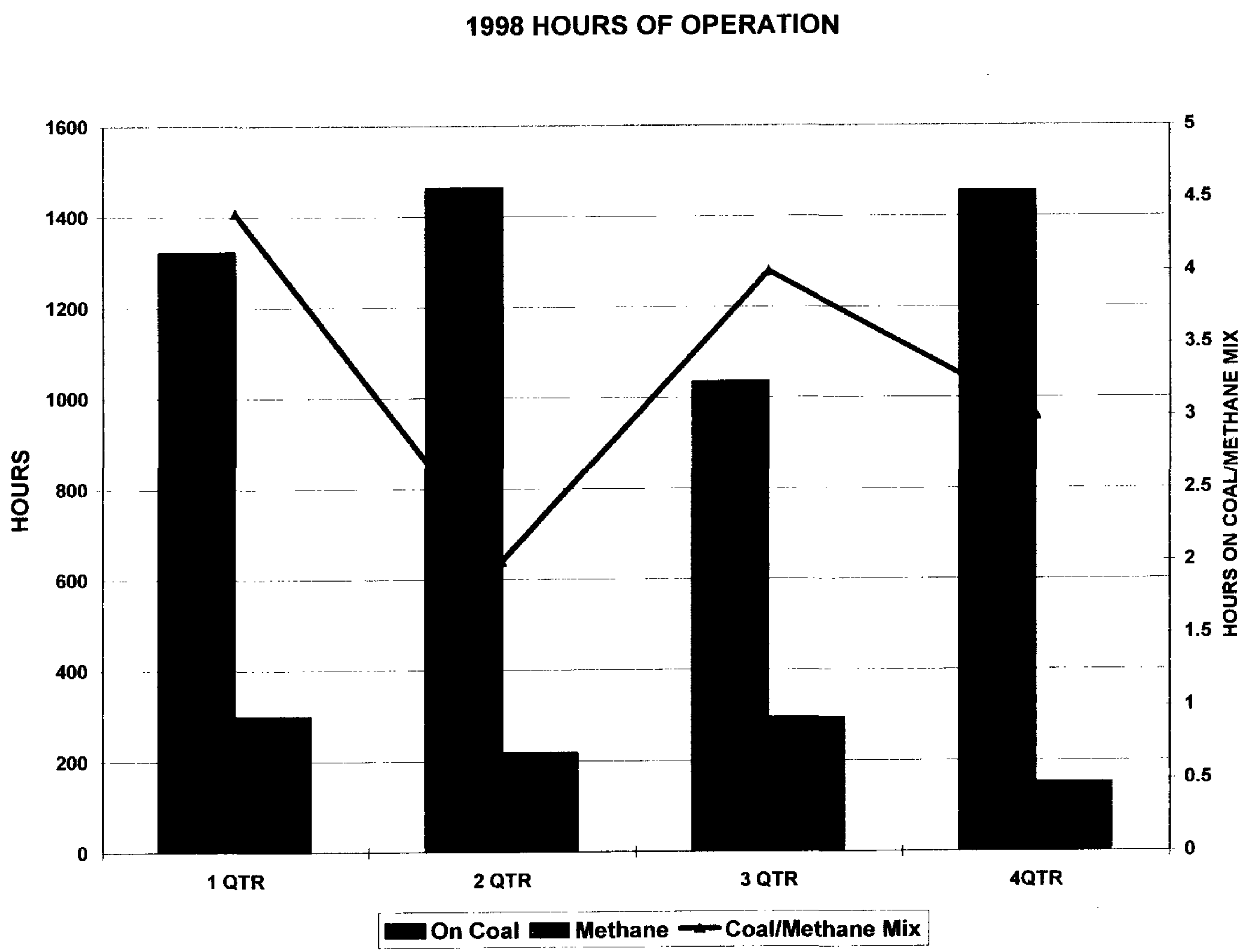
	JUN	JUL	AUG	SEP	OCT
PERFORMANCE DATA					
Coal Gas Efficiency	72.31	73.35	74.08	73.8	76.75
Gasifier on Coal (Hours)	336.78	272.72	455.69	307.05	667.99
PRODUCTION DATA					
Syngas on Spec (MMBtu)	553705	447787	719963	480371	1155078
1600# Steam (Mlbs)	133854	119336	184989	120700	279726
Sulfur (Mlbs)	1533	1297	2016	1412	3359
Slag, Moisture Free (Tons)	4347	3555	5700	3863	8979
DELIVERED PRODUCTION					
Actual Syngas Delivered (MMBtu)	537357	433914	674473	473241	1134140
1600# Steam (Mlbs)	132120	119162	183203	119334	277888
MATERIAL/ENERGY USED					
Coal, Moisture Free (Tons)	30375	24842	39835	26994	62738
Coal (MMBtu)	747240	611131	979954	664061	1543395
Intermediate Pressure Steam (Mlbs)	11244	9620	13516	9602	16471
Electrical Power, Total (MWh)	20144	21109	23516	21202	25699
Oxygen, (Tons)	27725	22580	36459	24787	56270
Fuel Gas (Mlbs)	1306	461	1008	446	620
PLANT EMISSION DATA					
Average Total Sulfur in Syngas (ppm)	145.61	96.23	96.6	86.62	115.69
Total SO2 Emissions (lbs)	89772	43412	86815	60082	130601
SO2, (Total Plant lbs/MMBtu of Coal Feed)	0.118	0.067	0.084	0.082	0.084
POWER PLANT PRODUCTION DATA					
Combustion Turbine Generator (MWh)	68394	59783	84634	54447	132709
Steam Turbine Generator (MWh)	33400	26908	37109	25722	63601
Total Gross Generation (MWh)	101794	86691	121743	80169	196310
Total Syngas Generation (MWh)	89119	72179	106622	74794	196015

Monthly Plant Performance Data

	NOV	DEC
PERFORMANCE DATA		
Coal Gas Efficiency	76.72	78.64
Gasifier on Coal (Hours)	694.96	93.18
PRODUCTION DATA		
Syngas on Spec (MMBtu)	1215447	160062
1600# Steam (Mlbs)	284480	38088
Sulfur (Mlbs)	3436	386
Slag, Moisture Free (Tons)	9548	1230
DELIVERED PRODUCTION		
Actual Syngas Delivered (MMBtu)	1182704	156746
1600# Steam (Mlbs)	282319	36504
MATERIAL/ENERGY USED		
Coal, Moisture Free (Tons)	66742	8592
Coal (MMBtu)	1641138	211371
Intermediate Pressure Steam (Mlbs)	16320	6317
Electrical Power, Total (MWh)	25343	16743
Oxygen, (Tons)	59076	8117
Fuel Gas (Mlbs)	113.9	847
PLANT EMISSION DATA		
Average Total Sulfur in Syngas (ppm)	133.01	131.61
Total SO2 Emissions (lbs)	148110	23733
SO2, (Total Plant lbs/MMBtu of Coal Feed)	0.09	0.089
POWER PLANT PRODUCTION DATA		
Combustion Turbine Generator (MWh)	136975	21778
Steam Turbine Generator (MWh)	65738	9681
Total Gross Generation (MWh)	202713	31459
Total Syngas Generation (MWh)	201837	23341

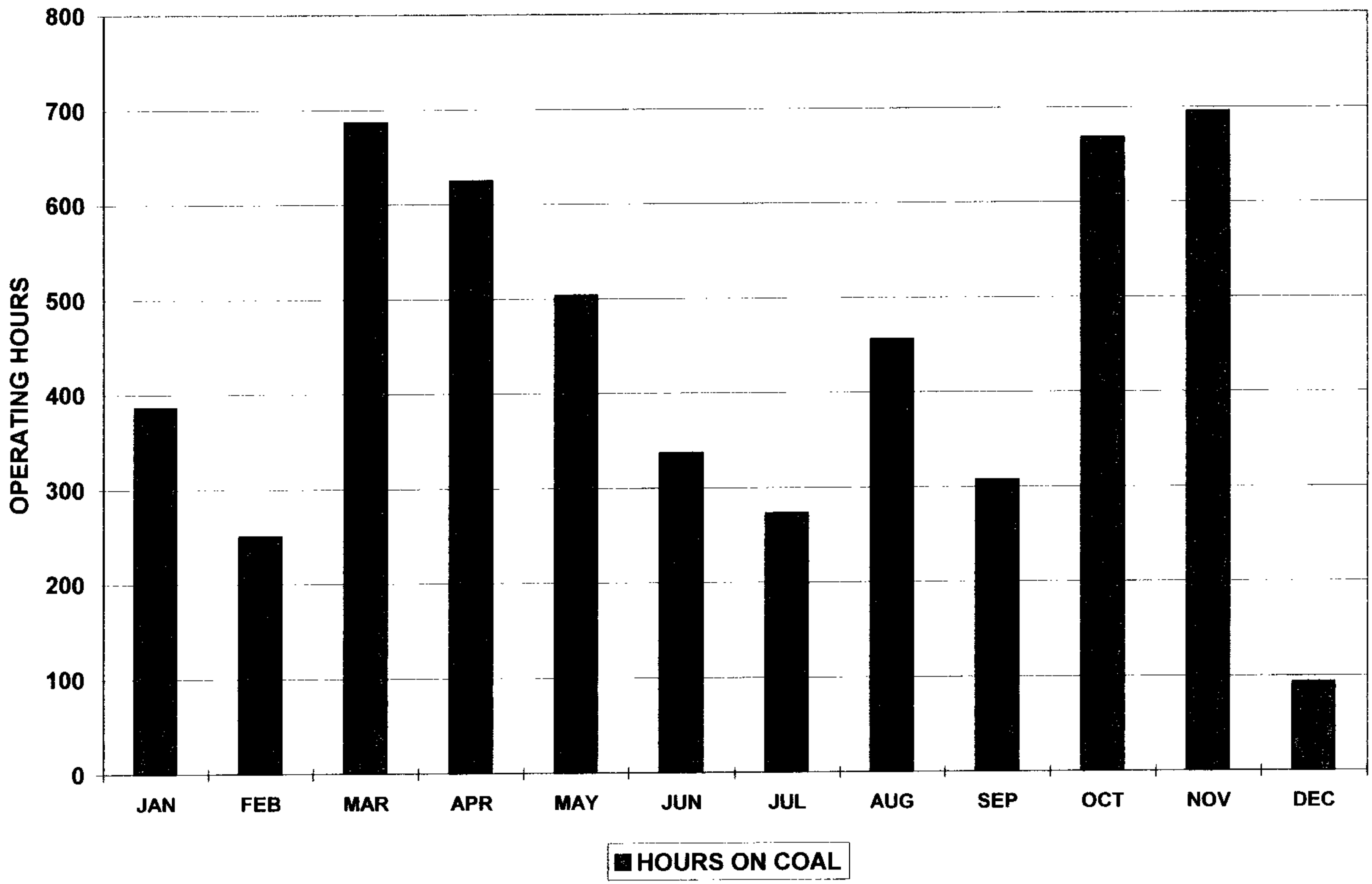
1998 COLD GAS EFFICIENCY

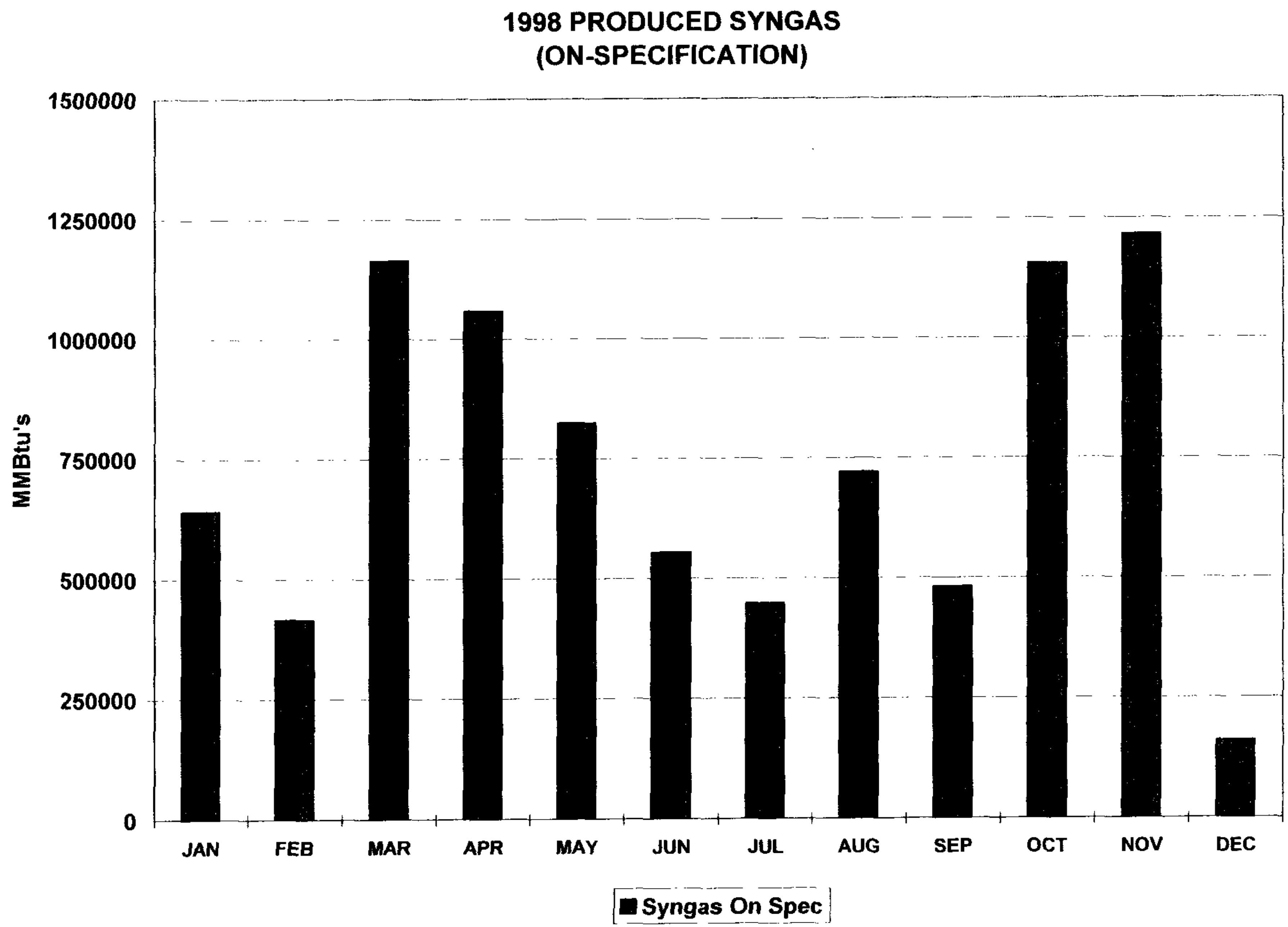


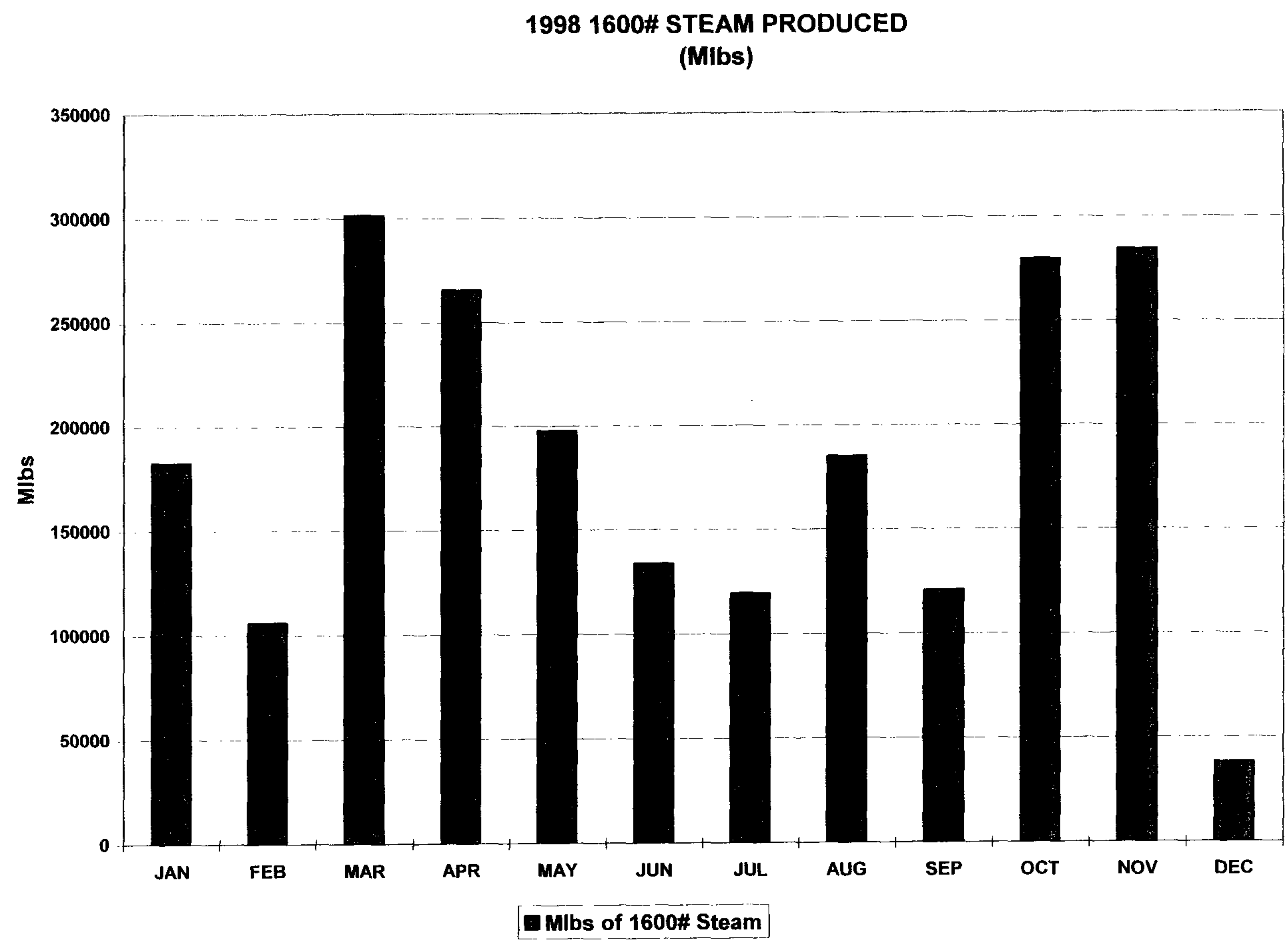


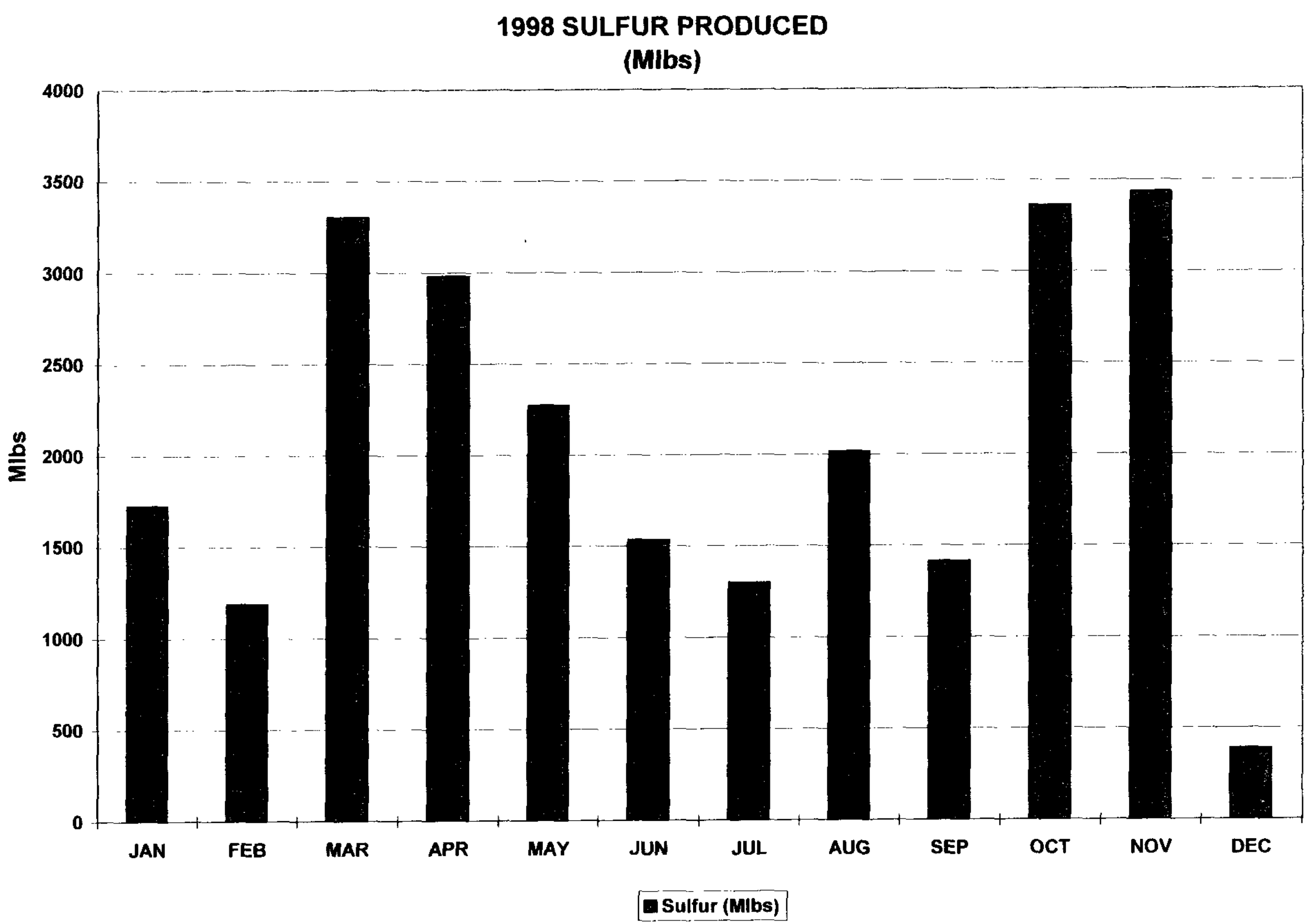
1998 HOURS OF OPERATION
HOURS
1600
1400
1200
1000
800
600
400
200
0
HOURS ON COAL/METHANE MIX
5
4.5
4
3.5
3
2.5
2
1.5
1
0.5
0
1 QTR
2 QTR
3 QTR
4QTR
On Coal
Methane
Coal/Methane Mix

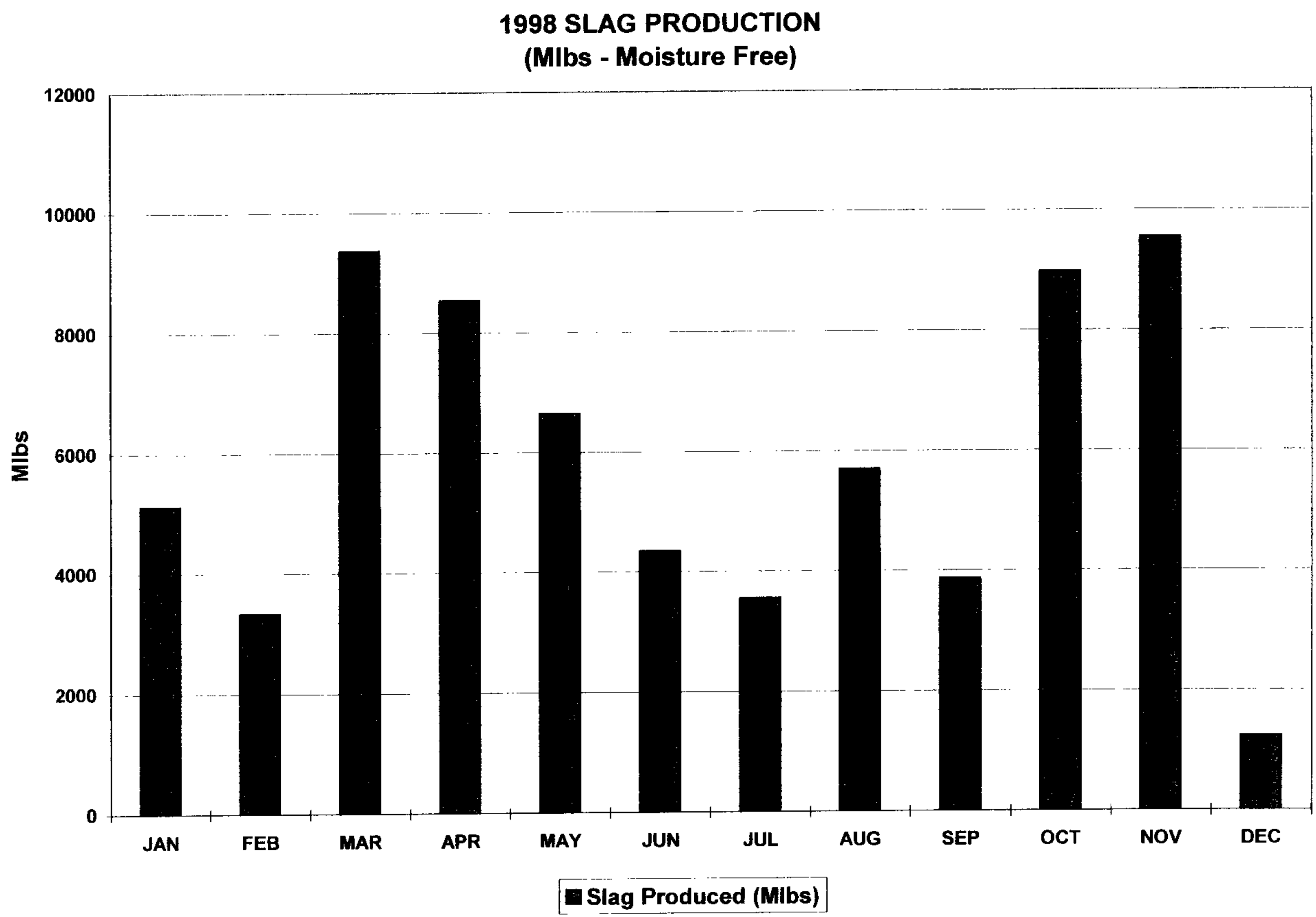
1998 GASIFIER HOURS ON COAL

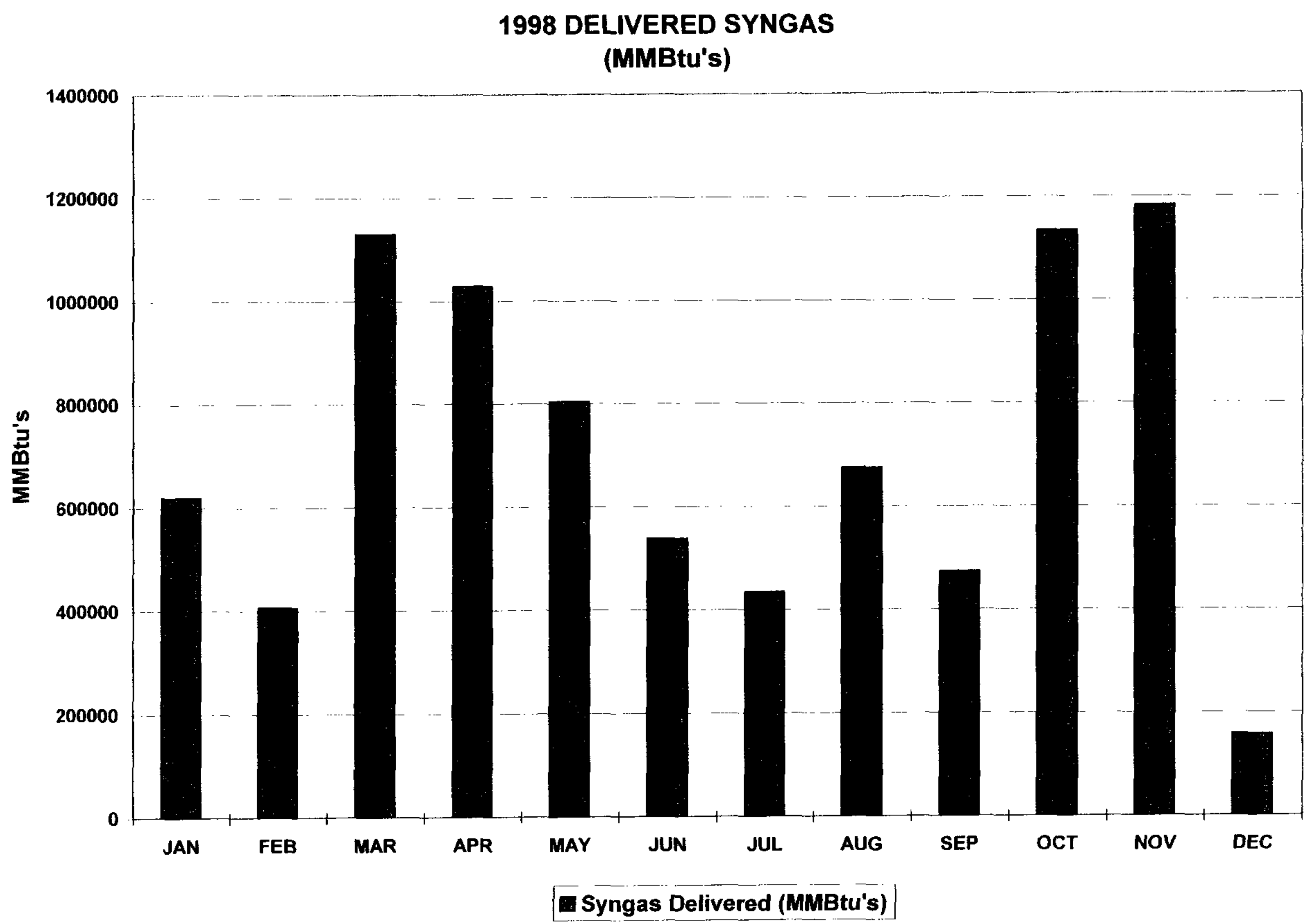



1998 PRODUCED SYNGAS
(ON-SPECIFICATION)
1500000
1250000
1000000
750000
500000
250000
0
MMBtu's
JAN
FEB
MAR
APR
MAY
JUN
JUL
AUG
SEP
OCT
NOV
DEC
Syngas On Spec

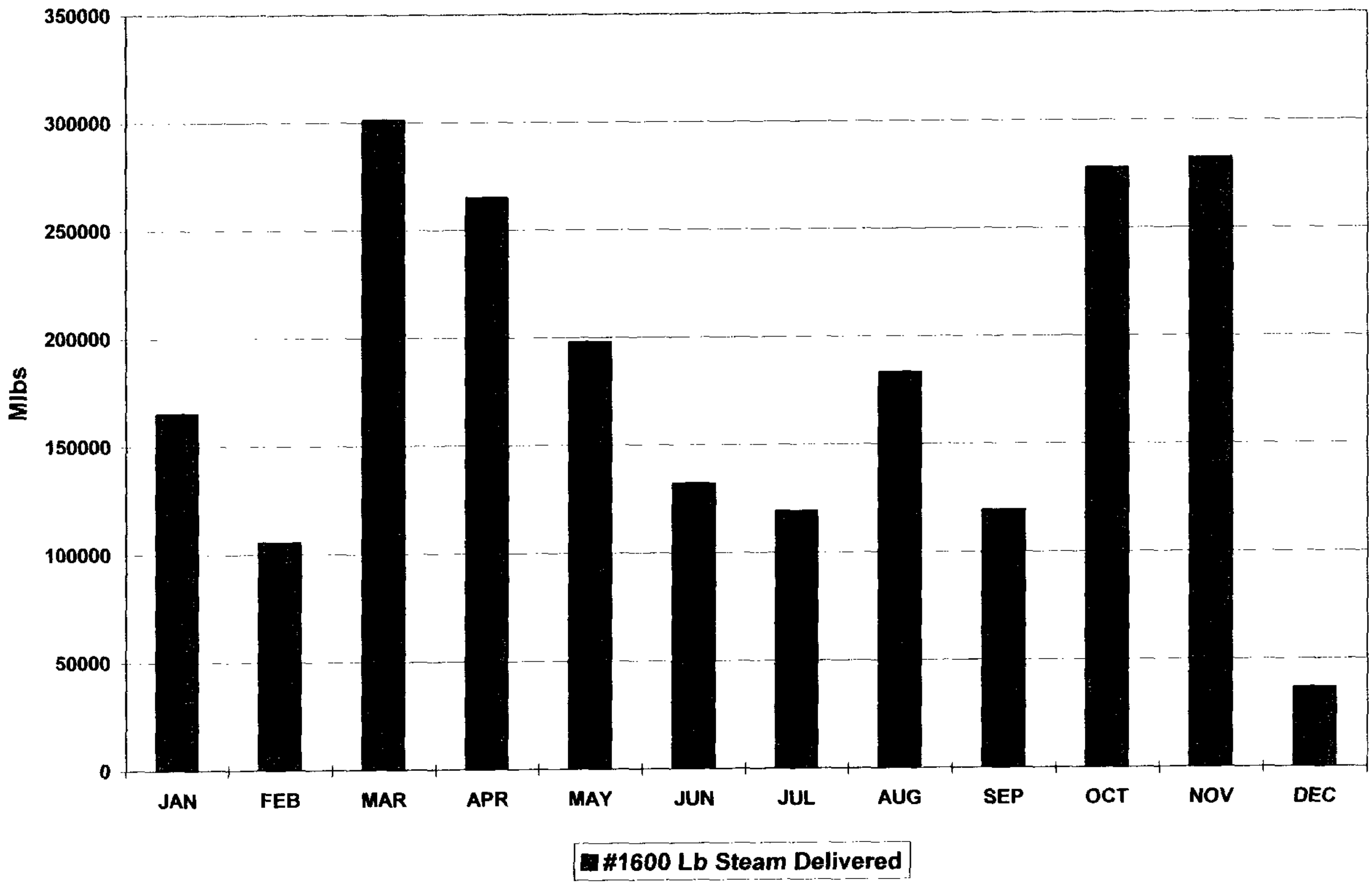

1998 1600# STEAM PRODUCED
(Mlbs)
Mlbs
350000
300000
250000
200000
150000
100000
50000
0
JAN
FEB
MAR
APR
MAY
JUN
JUL
AUG
SEP
OCT
NOV
DEC
Mlbs of 1600# Steam


1998 SULFUR PRODUCED
(Mlbs)
Mlbs
4000
3500
3000
2500
2000
1500
1000
500
0
JAN
FEB
MAR
APR
MAY
JUN
JUL
AUG
SEP
OCT
NOV
DEC
Sulfur (Mlbs)

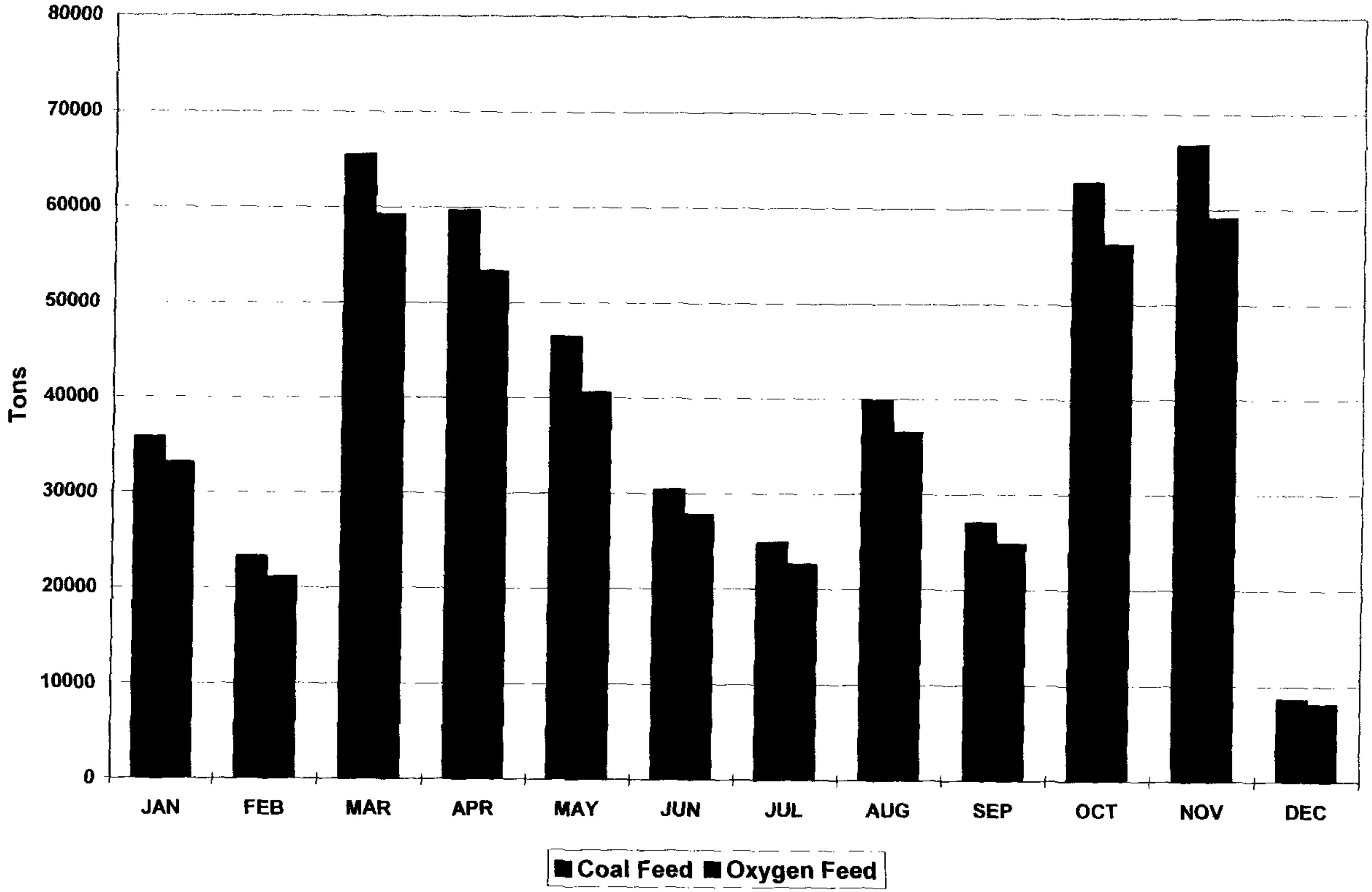

1998 SLAG PRODUCTION
(Mlbs - Moisture Free)
12000
10000
8000
6000
4000
2000
0
Mlbs
JAN
FEB
MAR
APR
MAY
JUN
JUL
AUG
SEP
OCT
NOV
DEC
Slag Produced (Mlbs)

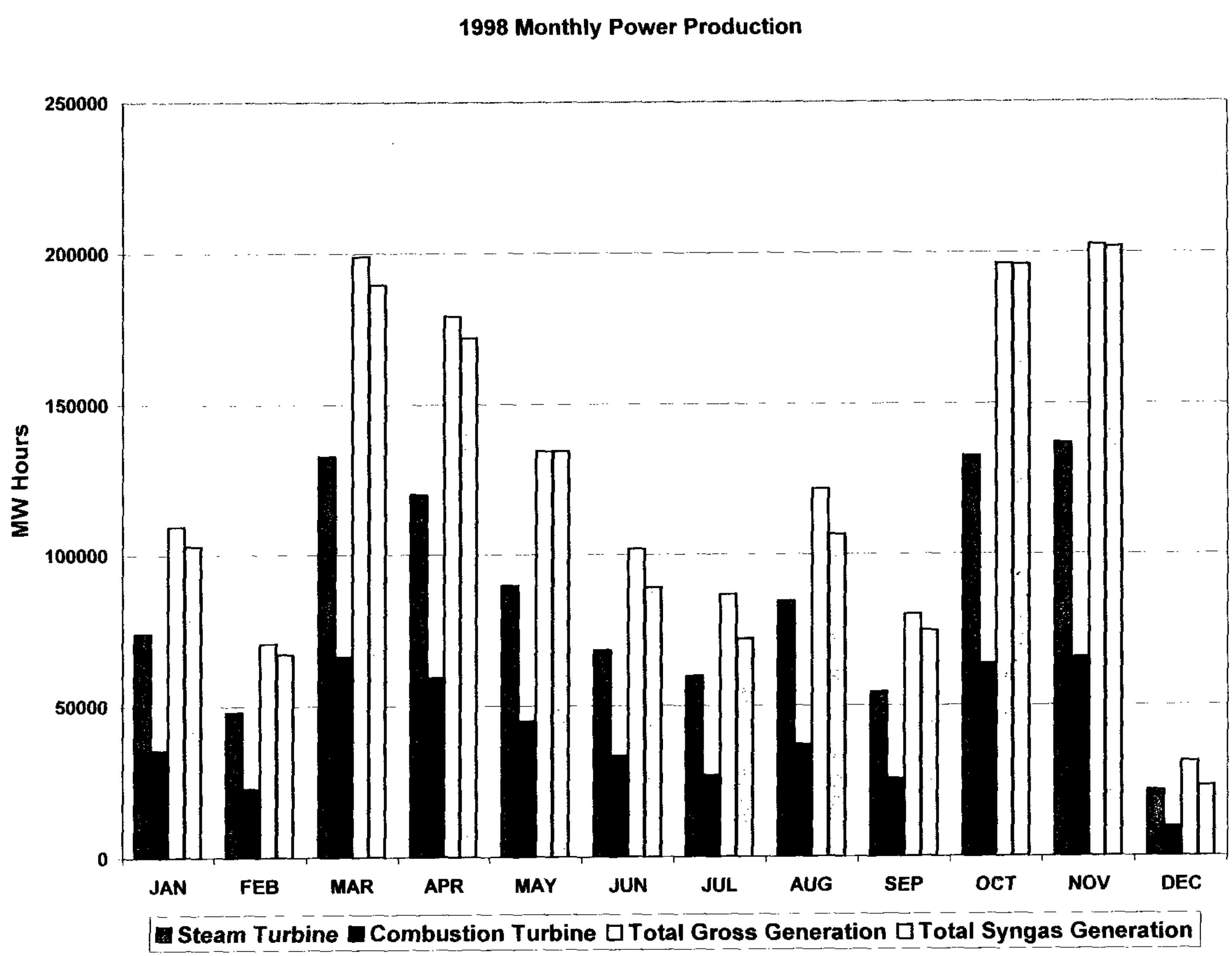

1998 DELIVERED SYNGAS
(MMBtu's)
MMBtu's
1400000
1200000
1000000
800000
600000
400000
200000
0
JAN
FEB
MAR
APR
MAY
JUN
JUL
AUG
SEP
OCT
NOV
DEC
Syngas Delivered (MMBtu's)

1998 DELIVERED #1600 LB STEAM
(Mlbs)

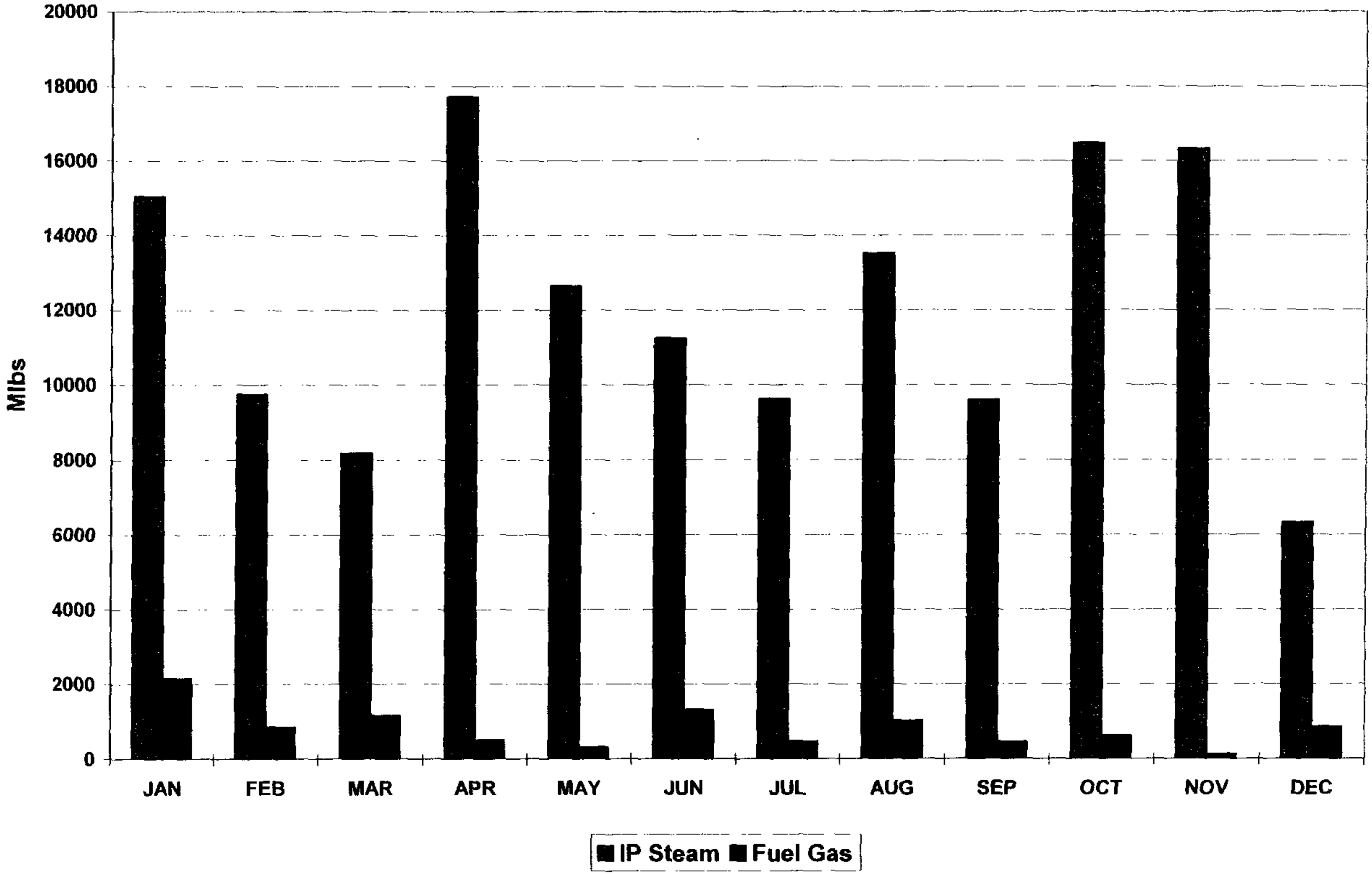


1998 FEED TO GASIFIER
(TONS)

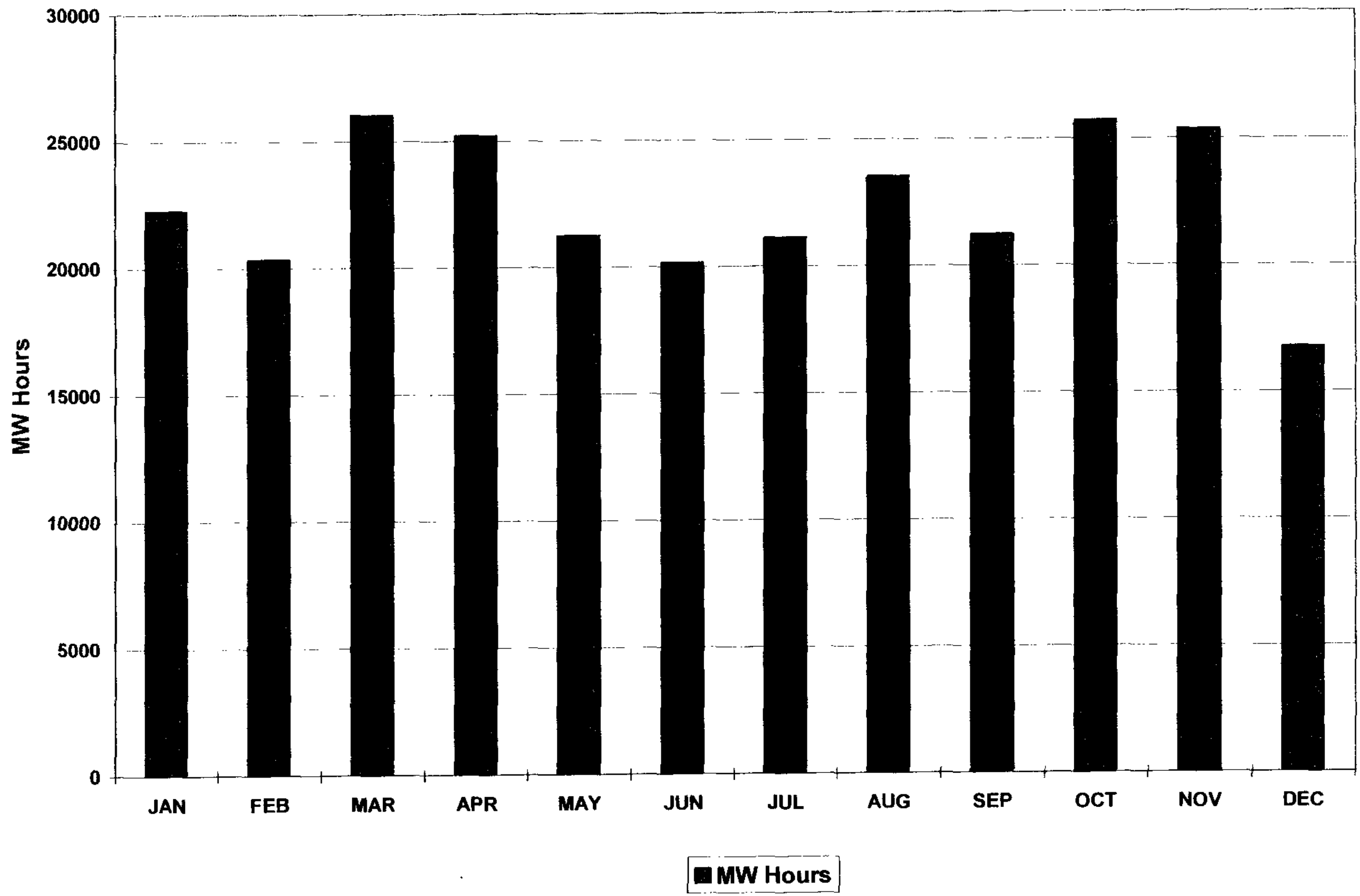



1998 Monthly Power Production
250000
200000
150000
100000
50000
0
MW Hours
JAN
FEB
MAR
APR
MAY
JUN
JUL
AUG
SEP
OCT
NOV
DEC
Steam Turbine
Combustion Turbine
Total Gross Generation
Total Syngas Generation

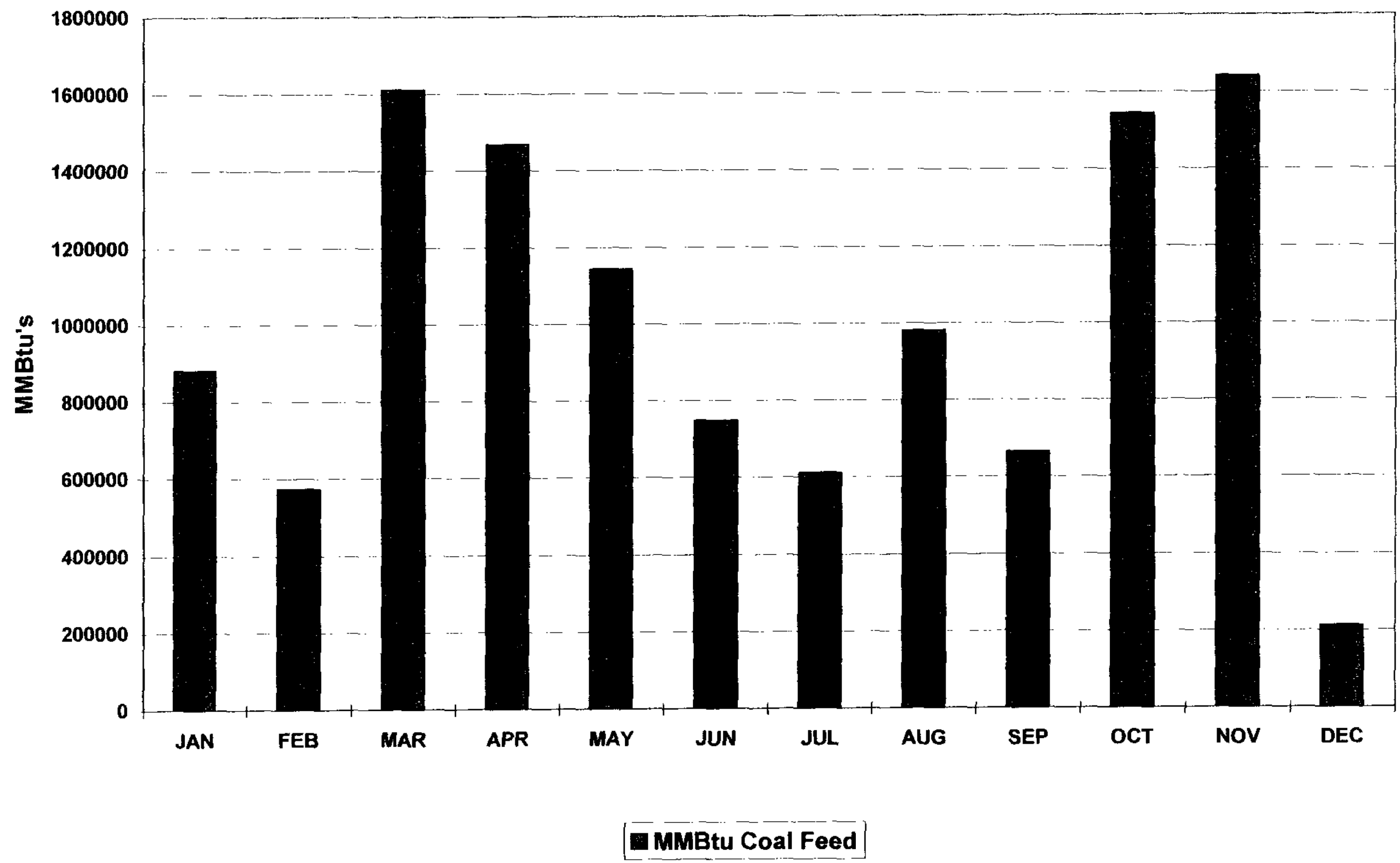
1998 ENERGY UTILIZATION (GASIFIER)
(Mlbs)

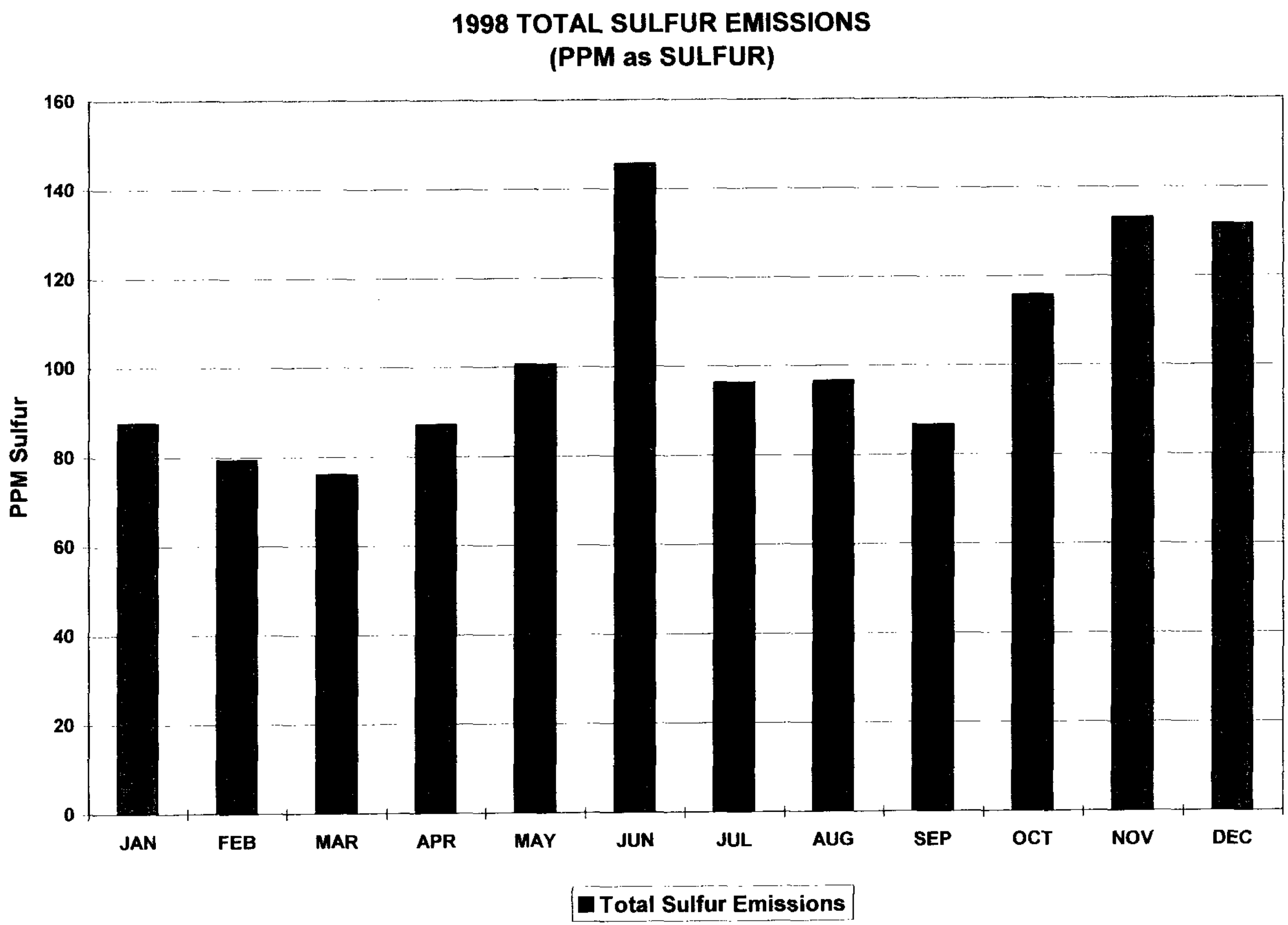


1998 ELECTRICAL ENERGY UTILIZATION
GASIFICATION PLANT (MWH)



1998 COAL FEED TO GASIFIER
(MMBtu's)




1998 TOTAL SULFUR EMISSIONS
(PPM as SULFUR)
PPM Sulfur
160
140
120
100
80
60
40
20
0
JAN
FEB
MAR
APR
MAY
JUN
JUL
AUG
SEP
OCT
NOV
DEC
Total Sulfur Emissions

1998 POUNDS OF SO_2/MMBtu OF COAL FEED (TOTAL REPOWERING EMISSIONS)