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1.0 ABSTRACT

This study examines the feasibility of applying the concepts of Coal Gasification and Combined Cycle Technology to the re-powering of existing steam turbine-electric generating facilities. The primary objectives of this study include (1) the determination of the feasability of designing a technically sound system embodying this technology; (2) the determination of the potential for displacing foreign oil by the project; (3) the identification of any constraints and/or barriers that might impede the accomplishment of such a project; and (4) the evaluation of the potential benefits of such a system.

The design as developed in this study utilizes two existing steam turbine generators, Units #9 and #11 (approximately 30MW and 35MW in size, respectively) at United Illuminating's Steel Point Station in Bridgeport, Connecticut. Steam for operating these units would be supplied, in part, from a Heat Recovery Steam Generator (HRSG) which extracts heat from the hot exhaust gasses of a 108MW combustion turbine. This turbine would be fired with a low Btu fuel gas from a Coal Gasifier System which, for purposes of developing this study, is a Westinghouse air blown system, similar to the Westinghouse Process Development Unit (PDU) located at Waltz Mill, PA. Heat is also recovered in the gas cool-down system located in the outlet from the gasifier, where superheating of steam originating in the HRSG occurs.

The gasifier is capable of utilizing the same range of coals which would be burned in Unit #3 at Bridgeport Harbor Station if that unit were on coal. All of the coal preparation facilities necessary to operate the gasifier, as well as all facilities necessary to meet air and water discharge quality requirements have been considered and are included in the design and cost estimates. Coal delivery is assumed to be by barge with short term storage provided at the Steel Point site. Long term storage would be maintained at Bridgeport Harbor Station where extensive coal handling equipment, including a continuous bucket barge unloader, now exists.

Although the system is designed around the use of commercially available, state-of-the-art components and equipment, a completely integrated, electric generating plant, such as is being proposed here, has not yet been demonstrated. However, the designs developed as part of this study combine these components, utilizing well developed and technically sound concepts in such a way as to provide a reasonable degree of confidence in the workability of the total system.

In addressing economics of the project, a number of different scenarios were tested for sensitivity where it was determined that certain assumptions had a fair degree of uncertainty associated with them.

This study represents one element of a many faceted effort now under-way within United Illuminating to address its future energy needs. This particular study is of interest to UI because it offers (1) the potential for reducing oil dependency; (2) the possibility of improving cycle efficiency and extending the useful life of existing facilities; (3) the feasibility of re-vitalizing a facility located within a major load center which would enhance electric reliability and present some attractive possibilities for a co-generation, district heating application in the central portions of Bridgeport.

Although the results of the study produce a number of clear conclusions, they also stimulate additional questions, the resolution of which would require further study and more detailed design.

The final resolution of these questions that still remain may have a significant effect on the final conclusions concerning the viability of this project, and it is for this reason that further study is required.

2.0 EXECUTIVE SUMMARY

2.1 Perspective

The United Illuminating Co. (UI) is an investor owned utility serving the electric requirements of approximately 280,000 customers in the south central part of Connecticut (New Haven, Bridgeport, and the surrounding communities). UI's service territory covers an area of about 335 square miles.

UI presently depends on foreign oil for approximately 92% of its electric generations requirements. A major effort has been and continues to be directed toward reducing this dependency. This presently includes participation in several New England Power Pool (NEPOOL) "pool planned" nuclear units, the burning of Refuse Derived Fuel (RDF) at its Bridgeport Harbor Station Unit #1, and the planned burning in Unit #2, and the possible conversion of Unit #3 at Bridgeport Harbor Station to coal.

Consistent with UI's objective of reducing its dependency upon oil to the greatest extent possible, UI embarked on a study of utilizing coal derived fuel in existing equipment at one of its generating facilities. The concept centers around the "re-powering" of steam turbine equipment by means of a "combined-cycle" system which employs a gas turbine and a heat recovery steam generator topping cycle. This concept is not new to the industry. In fact, many combined cycle systems are presently in operation. However, in this case, the source of fuel for the combustion turbine is somewhat unique in that it is in the form of a low Btu gas supplied from a coal gasifier. The fuel gas is "cleaned up" prior to being burned in the combustion turbine, thereby, addressing the emissions problem normally associated with the direct burning of coal as a fuel. This design increases the capacity of the existing cycles, and improves their efficiency. The use of coal would displace the oil burned in the cycles being studies and elsewhere within United Illuminating's system.

2.2 Study Objectives

This study was undertaken to determine the feasibility of designing, constructing and operating a combined-cycle, coal gasification system utilizing state-of-the-art equipment and relatively proven engineering concepts. In addition, the economic viability of the project was to be examined with particular attention given to the potential for cost savings and displacement of oil. Also, an objective of the study was to identify any constraints and/or barriers that might prevent or delay the implementation of such a project.

2.2 Study Objectives (Cont'd.)

The economics of installing and operating such a system will be compared with that of other alternatives, such as the conversion of UI's Bridgeport Harbor Station Unit #3 to coal, so that the relative cost effectiveness of the various options can be evaluated.

2.3 Description of Systems

The equipment considered for re-powering in the study includes Units #9 and #11 steam turbine generators at United Illuminating's Steel Point Station in Bridgeport, Connecticut. Unit #9 is a 30MW General Electric machine which was placed in service in 1941. Steam at 625 psi, 850 F, is supplied to this machine by two (2) oil fired, Babcock and Wilcox "F" type boilers (converted from coal to oil in 1967).

Unit #11 is also a General Electric machine approximately 35MW in size. It was placed in service in 1950. Steam at 900 psi, 900 F is supplied to this turbine from a single Babcock and Wilcox "RB" type oil fired boiler (converted from coal to oil in 1967).

The Steel Point site as shown in Chart I is located in an urban area in Bridgeport and has docking facilities on Bridgeport Harbor. Sufficient space is available at this site for the construction of the facilities required for this project. Although some coal could be stored on the site (approximately 15 days supply), it is anticipated that primary long term coal storage would be at UI's Bridgeport Harbor Station. Bridgeport Harbor Station is directly across the harbor from Steel Point Station. A 75 day supply would be stored at this location with barge transfer to Steel Point on an as-needed basis. The coal used in the gasifier will be compatible with the coal that would be burned in Bridgeport Harbor Station Unit #3 if it were converted to coal, thereby eliminating the problems associated with maintaining separate inventories. The proposed site layout for coal storage and the coal gasification facilities is shown on Chart II.

The system design includes the installation of a new 108MW gas fired Combustion Turbine with a Heat Recovery Steam Generator (HRSG) in its exhaust. A significant quantity of heat is also recovered in the Gas Cooldown section of the Coal Gasification System, and the steam generated in these two areas is utilized by #9 and #11 steam turbines for electric generation. A schematic diagram of the proposed system is shown on Chart III.

2.3 Description of Systems (Cont'd.)

Fuel gas for the combustion turbine is supplied from a Westinghouse Coal Gasification System where a low Btu gas is produced (approximately 150 Btu/SCF). The gas is cleaned prior to use in the Combustion Turbine to provide an environmentally compatible and relatively efficient coal-to-electricity cycle. The coal gasification/combined cycle system developed in this study has been designed with operating flexibility in mind, although it would probably be operated in a base load mode most of the time in view of its relatively competitive production cost. The gasification system is modularized. This modular approach, along with the ability to operate the combustion turbine on fuel oil, tends to increase the availability and operability of all or part of the capacity of the system. Although much of this flexibility was not considered in the preliminary runs of the economic analysis, subsequent sensitivity scenarios examined the effect of these considerations.

Further the designs were developed such that the ability to operate the #9 and #11 cycles in their present configuration is not compromised.

2.4 Potential Impact

Construction of the facility proposed in this study would result in (1) the conversion of 60-65MW of existing oil fired capacity to coal and, (2) the addition of approximately 108MW of new coal fueled capacity to the system. It would also result in significant improvements in the total cycle efficiencies (including Units #9 and #11), allowing this equipment to be competitive with many newer units on the system. It could therefore, result in the returning to effective use of older equipment which might otherwise see limited use because of its low efficiency and oil based energy source.

The installation of the system described in this study offers the potential for displacing approximately 1,000,000 barrels of oil annually. However, the actual amount will be dependent on many factors which include such things as system load growth, the addition of other non-oil-fueled generating capacity, and system availability.

2.5 Site Considerations

Although most of the components being considered in making up the system are state-of-the-art and relatively proven, the integration of these components into a coordinated system such as is required in this scheme is a relatively new element.

2.5 Site Considerations (Cont'd.)

Similar projects are in design but no actual operating experience is available. Accordingly, this particular project offers some unique opportunities to gain operating experience on an electric utility system.

Steel Point Station, including Units #9 and #11 are presently used in a peaking mode of operation because of the availability of other more competitively priced generating facilities. The limited need for these facilities in the immediate future would allow for their use in developing and demonstrating a relatively unproved concept with its early inherent lack of reliability and/or availability. Retention of the ability to operate the equipment in its present mode would allow such demonstration to proceed without exposing UI's system to a reliability loss.

The existing equipment that would be used in the system is very compatible with the additions being proposed both from a size and a steam requirements view point and its condition is such that many more years of reliable operation can be reasonable expected.

The site of the proposed installation offers many unique features as well as some rather difficult problems. Its urban location presents some interesting opportunities but also presents problems in the form of limited land area and environment considerations. Particular attention was given in the conceptual design to both air and water pollution impacts.

The plant is located in a region of the country that has become extremely dependent on foreign oil and has a desperate need for establishing viable alternatives. Demonstration of solutions to problems unique to this region such as environmental, transportation and waste disposal will be useful in evaluating other similar applications.

The existing facility also offers some interesting challenges concerning the feasibility of re-powering relatively old but still useful equipment and accomplishing this in such a way as to make the total cycle efficiency competitive with newer generating units. Also, because of the location and the variety and type of equipment at the station, the facility could become part of a co-generation district heating project currently under examination in Bridgeport.

The urban location of this generating station, offers an opportunity to locally supply some of the electrical needs of a major load center. This would contribute to reliability and reduce the need for additional transmission lines into the area.

2.5 Site Considerations (Cont'd.)

The type and variety of equipment at Steel Point Station offers the very significant advantage of flexibility of operation that is so necessary in developing and demonstrating a new technology. This is an extremely important consideration in evaluating a project of this type.

The plant site is adequate in size to accommodate the installation of all of the equipment required for the project including coal storage (15 days), fuel preparations, fuel gas cleanup, and waste treatment facilities. In addition, its proximity to Bridgeport Harbor Station with its existing coal barge unloading and handling facilities, is such that supplemental coal storage for an additional 75 days can be effectively provided at that site.

2.6 Technology Assessment

This study has resulted in the design of a power generation system which is reasonably compatible with standard utility requirements for such systems. This includes flexibility of operation to allow for changing load situations as well as addressing the standards of reliability and availability for such equipment.

All of the equipment and components making up this integrated system have been shown to be commercially available. Although a system such as this has not yet been operated on an integrated basis, proven technology has been utilized in developing the system resulting in a high degree of confidence for the successful operation of the system. Some of the areas in which some uncertainty still remains include (1) reliability and availability of the gasifier and (2) the burning of low Btu gas in the Combustion Turbine and the long term effects on turbine components as a result of using this fuel.

Although components of specific manufacturers were used in the study in order to arrive at some realistic cost estimates, there are many alternatives available, which would have to be more fully evaluated if this project were to proceed beyond the feasibility study phase. However, it is felt that the overall impact of considering the use of equipment other than what was assumed in the original conceptional design, would be small and would not significantly affect the conclusions that result from the study. Other factors that could have significant impact on the competitiveness of this concept when compared to other alternatives include evolving developments in the area of High Temperature Gas Turbine design and Hot Gas Desulfurization Systems. However, these concepts are, at this time, considered to be developmental and are not, therefore, evaluated in this study.

2.7 Environmental Considerations

With respect to air pollution regulations, the Coal Gasification System will be classified as a new source. It is expected that the air and water pollution control equipment included as part of this system will bring all emissions into compliance with applicable emission and discharge standards.

However, because of the magnitude of emissions of SO_2, the system will be subject to Prevention of Significant Deterioration (PSD) review. At this time, no PSD Permit Applications have been filed in Connecticut. Should this be the first such application, it would set a so-called "Baseline Date" and "Baseline Concentration" for the Bridgeport area and would consume some portion of the air resources available for other SO_2-emitting projects in the future. Detailed air quality analyses would be required.

In addition, the Bridgeport area is presently exceeding the secondary ambient air standard for Total Suspended Particulates (TSP). As a result, it is likely that all emissions of TSP from the Coal Gasification System would have to be "OFFSET" by equal or greater reductions of TSP emissions from other sources in the area.

Ash from the gasifier appears to be acceptable for landfill purposes which therefore, makes it more easily handled and disposed of than that which is produced by more conventional means. Also, the fuel gas clean-up systems that are proposed produce elemental sulfur that is suitable for resale rather than a product that has no useful purpose and could be costly to dispose of. In addition, the methods used in the fuel-gas clean-up are ones that are tried and proven as being commercially available and reliable.

Overall, from an environmental point of view, the Coal Gasification Combined Cycle system being proposed would appear to produce air, water and solid waste impacts, at least as acceptable as, and perhaps more-so, than most other alternatives that would allow the use of high sulfur coal.

2.8 Environmental Assessment

It has been reasonably established that the system being proposed herein can be constructed on the Steel Point site and operated in an environmentally acceptable manner. Disposal of ash and sulfur must be addressed further but should present less of a problem than would be encountered with the direct burning of coal. Because of its urban location, considerable attention would have to be given to the aesthetic aspects of this facility, but it is felt this potential problem could be successfully addressed. Other areas that would require further study and consideration

2.8 Environmental Assessment (Cont'd.)

include; (1) the effect of cooling towers; (2) vehicular traffic; (3) dredging and construction in navigable waters; (4) noise, and (5) flaring of gas from the gasifier during periods of emergency.

2.9 Costs

Capital, operating and maintenance cost estimates for the study were developed by Dravo Corporation with some input from UI. These estimates were prepared utilizing a variety of sources including (1) equipment or system supplier estimates; (2) sub-contractor estimates; (3) vendor quotes, and (4) Dravo in-house estimating data. The source of data for all of the major cost items in the system is shown in the cost breakdown summary found in Section 8 of the report. The total project cost is estimated to be $90,000,000 in 1980 dollars. A breakdown showing the costs for each area of the system is given below.

Area	Installed Cost
Fuel Supply and Preparation	$ 7,774,000
Coal Gasification	8,354,000
Fuel Gas Cleanup	18,667,000
Gas Combustion Turbine Generator	18,381,000
Heat Recovery	27,592,000
Utilities and Facilities	1,188,000
Water Treatment	1,341,000
Waste Treatment and Disposal	6,703,000
Total Project Cost (1980)	$90,000,000

The above estimate was further adjusted to account for UI costs, interest during construction and inflation consistent with start of construction in 1984 with completion in January, 1987. Also included was an allowance for coal storage in the amount of a 75 day working inventory. The total cost for the project, based on a January, 1987 start-up and including all of the above, is estimated to be $159,208,000.

The coal price used in UI's base economic study is $1.90 (1980) per million Btu's (delivered) which, for 12,500 Btu coal, results in a delivered cost of $45.00 per ton. The base coal price used in this study is consistent with the coal price used in the Bridgeport Harbor Station Unit #3 coal conversion studies performed by UI.

2.9 Costs (Cont'd.)

Operating and maintenance costs used in the study include manning requirements developed by Dravo as summarized in Section 9.0. Operating labor costs are based on data supplied to Dravo by UI, with maintenance costs based on a percentage of capital costs as shown in Figure 9.2 (Section 9) of the report. Additional variable expenses accounted for in the study include by-product disposal and raw material consumption resulting from the operation of the CG/CC system. All of these costs should be considered preliminary at this point but are adequate for purposes of this conceptual study.

2.10 Assumptions

All assumptions used in the economic studies were made consistent with those used in the coal conversion studies for Bridgeport Harbor Station and are listed below.

It was assumed that the system would come on line in January, 1987 with the study period extending from 1985 to 2004. An attempt was made to identify the project's sensitivity to changes in system load growth by using UI's low-band forecast of 1.9% (1980-1989) and 1.1% (1990-2004), and a load growth of 2.3% per year. Sensitivity to fuel prices was also determined by testing similar and different rates of escalation for coal and oil. The effect of assumed availability of the system was also tested.

The nuclear units in which UI is participating are assumed to remain on schedule, consistent with presently published in-service dates.

A summary of the more significant assumptions are listed as follows:

Plant Associated Costs

2.10.1 Costs

2.10.1.1 Total project cost based on indicated start-up date.

- o Installing CG/CC system for start-up in January, 1987.

  $127,076,000*
  16,716,000 AFC
  15,416,000 Working Capital

  $159,208,000 Total

2.10 Assumptions (Cont'd.)

- o Converting BPH 3 to coal with a SO_2 scrubber for start-up date in mid-1985.

  $ 97,114,000
  8,766,000 AFC
  31,468,000 Working Capital

  $137,348,000 Total

- o Converting BPH 3 to coal with a baghouse (no scrubber) for start up in mid-1985.

  $30,470,000
  2,701,000 AFC
  37,299,000 Working Capital

  $70,470,000 Total

*$90,000,000 (1980) escalated for 1/87 start-up on a "cash flow" basis.

2.10.1.2 Additional variable expenses (by-product disposal and raw material consumption by scrubber) resulting from burning coal. (Additional expenses for taxes, insurance and O & M etc. are presented in Appendix A).

- o BPH 3 with scrubber - 26.1¢ per million Btu in 1980 esc. at 7% per year.
- o BPH 3 without scrubber - 10.2¢ per million Btu in 1980 esc. at 7.5% per year.
- o CG/CC system - 10.2¢ per million Btu in 1980 esc. at 7.5% per year.

2.10.1.3 Low-sulfur coal -- 1-1/2% sulfur priced @ 200¢ per million Btu in 1980 and escalated annually at 7%.

2.10.1.4 High-sulfur coal -- 3-1/2% sulfur priced @ 180¢ per million Btu in 1980 and escalated annually at 7%.

2.10.1.5 Low-sulfur oil -- 0.5% sulfur priced @ 459¢ per million Btu at the end of 1979 and escalated annually at 7%.

2.10 Assumptions (Cont'd.)

2.10.1.6 High-sulfur Oil -- 2.2% sulfur priced @ $12/barrel (194¢ MMBtu) less than low-sulfur oil.

2.10.1.7 Refuse-derived-fuel -- 20% less expensive than oil. BPH 1 & 2 burning 60% oil and 40% RDF.

2.10.1.8 Ash disposal cost -- $17.50 per ton escalated annually at 7-1/2% from 1979.

2.10.2 Financial Associated Costs

2.10.2.1 Cost of Money (Non-Certifiable)

	Amount	Rate	Cost
Debt	50%	10.00%	5.00%
Pref. Stock	15%	10.00%	1.50%
Common Stock	35%	15.00%	5.25%
	100%		11.75%

2.10.2.2 Cost of Money (Certifiable Air and Water Pollution)

	Amount	Rate	Cost
Debt	50%	7.50%	3.75%
Pref. Stock	15%	10.00%	1.50%
Common Stock	35%	15.00%	5.25%
	100%		10.50%

2.10.2.3 State and Federal Taxes:

Federal income tax rate - 46%
Investment tax credit rate - 10%
Connecticut corporation business tax rate - 10%
Credit on state gross earnings tax - 5% of investment cost of air and water pollution control equipment.

2.10.2.4 Local taxes:

Property tax - Estimated Bridgeport mill rate, 66.9 applied to all non-certifiable capital expenditures after depreciation and equalization to 60% and 70% respectively.

Sales tax - 7.5% for all non-certifiable investments.

2.10 Assumptions (Cont'd.)

2.10.2.5 Depreciation:

	Book	Tax
Method	Straight Line	Sum-of-the years digits
Life	30 years	23 years

2.10.2.6 Insurance Cost:

0.1% of investment cost.

2.10.2.7 Escalation:

7% per year for capital investments
8% per year for highly labor-intensive work (e.g., O & M)

2.10.3 Other Assumptions

2.10.3.1 Load Growth:

UI low-band forecast (3-1-80 PFEC Report) of 1.9% (1980-1989) and 1.1% (1989-2004)

2.10.3.2 Study Period

1985 to 2004

2.10.3.3 Design Coal

Avg. Heat Value 12,500 Btu/lb, Ash 10%, Low Sulfur 1-1/2%, High Sulfur 3-1/2%

2.10.3.4 Unit data

o Coal Gasification/Combined Cycle System

The CG/CC system is not allowed to come off line except for scheduled overhauls (must-run unit)
Net capacity - 165.5 MW

o BPH 3 burning coal with a SO_2 scrubber

When burning coal, BPH 3 is not allowed to come off line except for scheduled overhauls (must-run unit)
Net capacity - 384.7 MW

2.10 Assumptions (Cont'd.)

- o BPH 3 burning coal with a baghouse (no scrubber)

  When burning coal, BPH 3 is not allowed to come off line except for scheduled overhauls (must-run unit)
  Net capacity - 388 MW

2.10.3.5 UI Nuclear Entitlements

The nuclear units must run at full load and are not allowed to come off line except for scheduled overhauls.

Unit	MW	Comm. Operation Date
Seabrook 1	189.8 (16.5%)	June, 1984
Seabrook 2	189.8 (16.5%)	April, 1986
Millstone 3	42.4	May, 1986
Pilgrim 2	37.9	June, 1987

2.10.3.6 Forced Outages of Generating Units

Forced outages of generating units are simulated by derating the unit using its estimated effective forced outage rate (EFOR).

2.10.4 Additional Studies - Assumptions

In the analysis presented in the addendum, the key assumptions are changed to the following:

- o Load Growth 2.3% per year
- o Coal and Oil Prices escalate annually @ 7% and 9%, respectively.
- o EFOR Schedule for CG/CC System:

Year	EFOR
1	64.5%
2	43.0%
3	36.6%
4	28.0%
5	28.0%
6 & Beyond	21.5%

This EFOR schedule was chosen to model the expected decrease in unscheduled outages as the CG/CC system matures. The schedule is based on data established by the NEPOOL

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2.10 Assumptions (Cont'd.)

Generation Task Force for the modeling of new coal-fired steam generating units.

For the purposes of the economic study, a combination of operating cases as described in Section 6.2 of the report were used. This was done to establish some operating flexibility so the facility would, within limits, respond to varying load conditions. For the maximum generation case (Case II) where excess steam appears to be available from the gasifier and combustion turbine Heat Recovery Steam Generator (HRSG), UI increased the output of #11 turbine from 30.8MW to 35.0MW so as to utilize all of the steam available from the system. This rating for Unit #11 appears to be reasonable based on past operating data, and running at this load results in effective use of all of the steam produced under this assumed scenario.

Other alternatives for utilization of the excess steam produced under these conditions could include directing it to #8 and #10 topping turbines with their exhaust supplying process heat in a co-generation mode or possible utilization of all of the excess steam above nameplate rating of #9 and #11 units for co-generation purposes directly. Detailed design would be required in order to establish the optimum use of this steam consistent with required matching of components.

2.11 Other Applications

The facilities at UI's English Station in New Haven (Units #7 and #8) closely approximate those at Steel Point (#9 and #11) in many respects. These similarities include unit size, unit heat rate and system dispatch. Although site layout and available land area at English Station are not ideally suited for the CG/CC layout as proposed for Steel Point Station, it is felt that with minor modifications, such a system could be installed at Engligh Station. It is also felt that the economics and conclusions resulting from this study could be applied to a similar proposal for Engligh Station with a reasonable level of confidence in their accuracy.

2.12 Summary of Results

It is apparent that the installation of a CG/CC System at Steel Point Station would result in a substantial reduction in UI's use of foreign oil. Oil savings could average 800,000 barrels per year with the low load growth scenario and in excess of 1 million barrels per year assuming a load growth of 2.3% per year.

2.12 Summary of Results (Cont'd)

It would also help in diversifying UI's fuel mix by further reducing its dependancy on any one particular source of fuel. The option to return to oil as a fuel if problems developed with the new equipment would also remain since the existing boilers would be left intact so that they could still supply steam to #9 and #11 cycles if required. The combustion turbine could also be fired on distillate oil if its capacity were needed and fuel from the gasifier were unavailable.

The rather impressive quantities of oil that would be displaced with the operation of this cycle, result in significant "production cost" savings.

Unfortunately, because of the lack of any need for additional capacity in our system during the time period covered by this study, no credit can be given toward the cost of the project for the new capacity resulting from the project (assuming present load growth predictions). Since the cost of this excess capacity will not be allowed into UI's base rate, all of the costs associated with the project are compared to savings resulting from the operation of the CG/CC system. This severely penalizes this option when compared to other alternatives which do not result in new capacity being added to the system.

These savings would vary depending upon the relative price of oil and coal as well as the capacity factor of the facility. The capacity factor in turn is impacted by factors such as electrical load growth and the availability of less expensive generation on the system. However, even given this wide range of assumptions, the savings that would result from the facility appear to be inadequate to offset the fixed and variable costs associated with the project during its early years of operations.

Attached Chart IV shows the amount of oil that would be displaced (expressed in MWHR's) by each of the programs UI is currently pursuing or considering and the degree of fuel diversification that would result from the successful implementation of these programs. Chart V displays this information in terms of oil displaced by these programs. It is estimated that, given the availability of the presently committed nuclear facilities and the successful conversion of BH #3 to coal, the operation of a CG/CC facility at Steel Point would further reduce UI's oil consumption by 950,000 barrels/year in 1980 as is shown on Chart V. Savings for other years are also shown on Charts IV and V. Possible additional savings that may result from an all New England dispatch are not considered in these analyses.

2.12 Summary of Results (Cont'd.)

Chart VI shows the economics associated with the installation of the CG/CC facility at Steel Point with Unit #3 converted to coal as the basis for comparison. Other major assumptions are identified on the Chart. It is evident that through 1992 cost penalties would arise from the installation of the CG/CC facility and these penalties would not be compensated for on a cumulative basis until 1995. The main body of the report discusses this analysis in further detail and also considers cases with differing assumptions. Essentially, Chart VI is representative of the general conclusions to be drawn from these various cases, and actually represents the case of least penalties.

The uneconomic nature of the facility during its early years of operation, is due in large measure to the nature of UI's projected capacity mix during the late 1980's and early 1990's and projected load growth during this period. The need for additional base load non-oil capacity during this period is limited by the anticipated presence of nuclear capacity and BHS Unit #3 on coal. Under these conditions, the CG/CC facility would generate sufficient revenues to cover total annual operating and maintenance costs but only part of those fixed costs associated with the installation of the system. Chart VII Curve #1 shows these penalties in the early years and the increasing contribution to fixed charges that could occur with time as a result of a projected load growth of 2.3% per year. In 1992, under these conditions, the project becomes essentially self supporting with projected revenues adequate to pay for the variable and fixed costs associated with the project. Chart VIII shows the cumulative savings that would result if fixed charges were excluded.

2.13 Conclusions

Based on a purely economic analysis of the CG/CC facility, it must be concluded that the facility cannot be justified, at best until the early 1990's. However, other considerations, of a non-economic but nevertheless significant nature, would tend to mitigate this conclusion.

The installation of this facility at the Steel Point site would provide a unique opportunity to demonstrate an unproven technology under actual system operating conditions. The site and the existing equipment offer a number of opportunities to address the many questions that must eventually be answered before this technology will be applied on a large scale. The study shows that the existing equipment at Steel Point Station

2.13 Conclusions (Cont'd.)

is very well matched with the new equipment being proposed and the existance of a variety of equipment allows for consideration of many combinations of cycle arrangements and energy saving concepts. For example, the Steel Point facilities include condensing turbines, non-condensing turbines,low pressure, intermediate pressure and high pressure cycles. Further, significant flexibility of operations and dispatch of equipment is possible because of the low demand expected in the next several years for this station. Also, the site is located in an urban area which has expressed an interest in, and has a high potential for district heating, thereby creating the possibilities for a combination "re-powering, co-generation-district-heating" project. These features provide a first hand learning experience for UI, other utilities, equipment vendors and the government and the opportunity to assess and further develop coal gasification technology for a number of different applications.

This site presents an opportunity to test a potential energy option in an urban setting where transportation, environmental and operational considerations can be evaluated and if successful, applied to other existing urban generating sites that are located at or near major load centers. Despite the numerous problems that surround such a concept, there are many positive aspects to such a proposal. These include the very significant advantages of increased system reliability, improved efficiency resulting from reductions in electrical transmission distances, and the rejuvenating of intra-structure made obsolete by changing technology. Obviously, all of the questions associated with the urban siting problems of such a facility would have to be addressed and answered if this project were to proceed. Many of these questions, as they apply to the Steel Point site, have already been investigated in a preliminary way in this study with the results indicating the prospects for actually licensing the Steel Point Site for such a purpose are encouraging. The results of an actual licensing effort at this site would be extremely helpful in evaluating the prospects for other similar installations.

The possibilities for further intergration of the CG/CC at Steel Point Station with district heating in the City of Bridgeport presents a very intriguing but realistic scenario for consideration. UI is presently involved in an in-depth study along with the City of Bridgeport to evaluate the feasibility of a district-heating project. Such an integration would even further increase the value of this project as a testing ground for these concepts.

2.13 Conclusions (Cont'd.)

As mentioned at the beginning of this section, it appears that this project cannot be economically justified, at best until the early 1990's. However, each of the areas discussed above has some value associated with it which must be evaluated not only by UI but by others who could potentially gain from this project moving ahead.

2.14 Recommendations

The conclusions of this preliminary study effort demonstrate that unique opportunities exist for a number of different but interested groups to attain desired goals. The study is also realistic in identifying constraints that exist in the form of possible regulatory impediments, financing requirements and the untried and unproven nature of the system proposed. The latter constraint is of particular significance when considering the estimated project investment of $160 million.

Though there have been demonstration projects with respect to the individual components proposed in the project, experience with an integrated package operating as an electric generating plant subject to daily dispatch is essentially lacking. The concept is very attractive though not only for re-powering applications, as analyzed herein, but also for wider application to new and larger electric generating facilities. Because of the lack of operating experience with such facilities and because it is well recognized that any new technology involves a learning curve, there will be a natural reluctance for the industry to commit to large electric generating facilities until proven experience on at least a smaller scale. The industry can only reasonably develop such technology and experience through progressive steps starting with the construction of smaller "no or low risk" facilities leading eventually to larger facilities fully supported by the operating utilities.

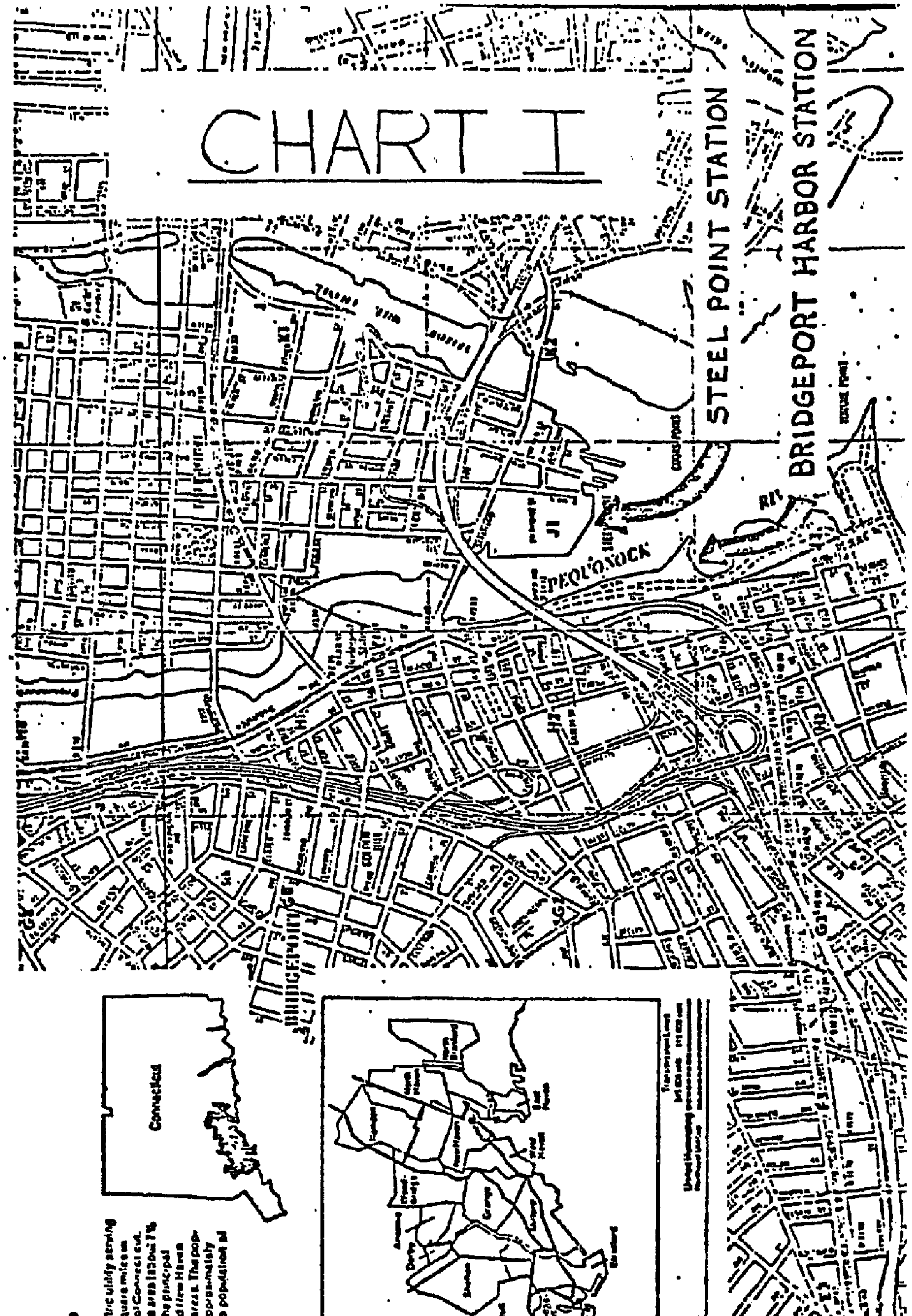
UI recognizes that Steel Point Station may be uniquely suited to be part of a demonstration effort designed to accumulate operating experience on a Combined Cycle Coal Gasification electric generating facility. It also recognizes that such a facility may have further potential as part of a co-generation district heating system now under study for the City of Bridgeport. The high risk nature of this effort, combined with the substantial capital requirements for UI's nuclear construction program over the next several years precludes UI from undertaking this project.

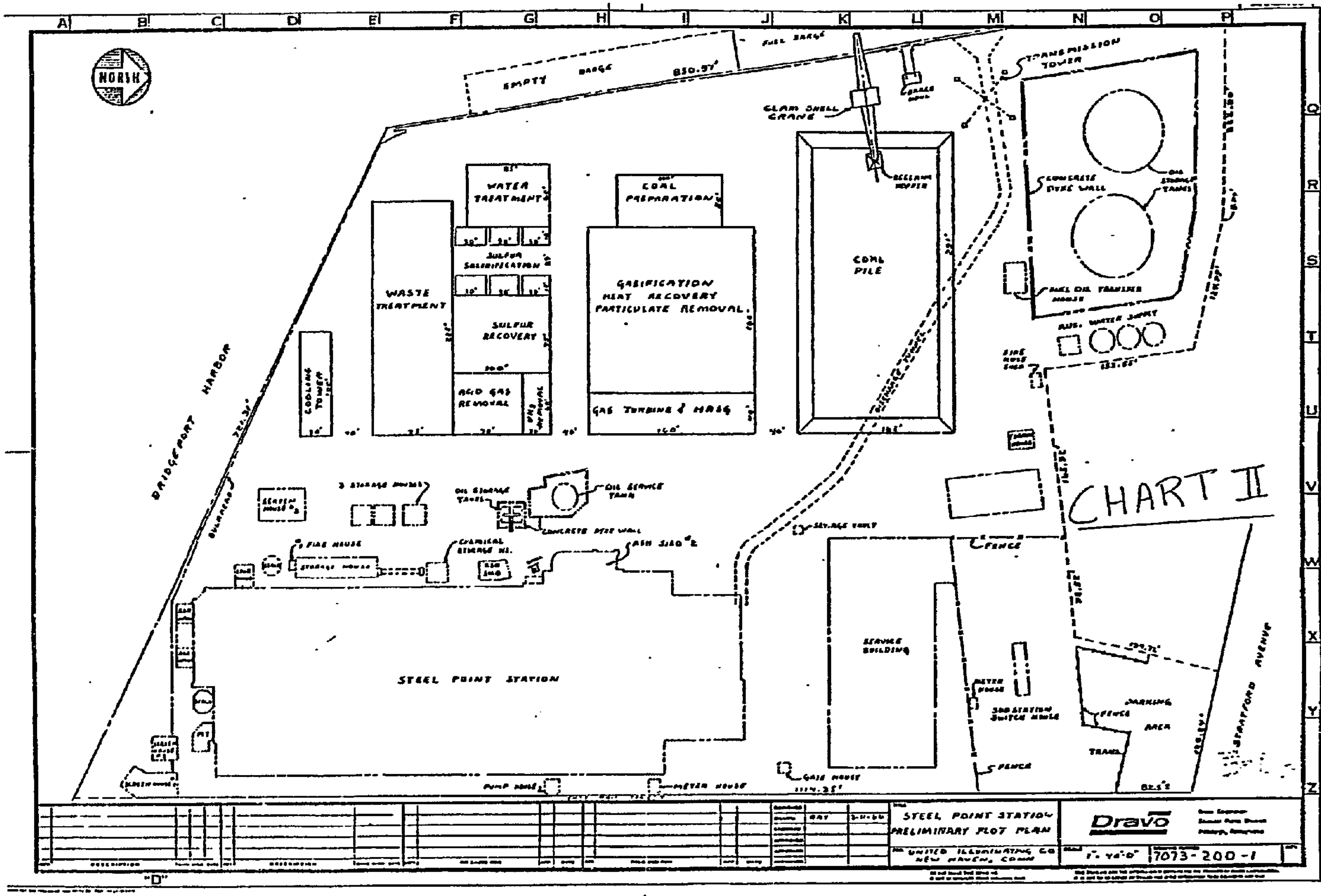
The situation is further compounded by the uncertainties associated with future load growth and the resultant point in time that the facility would be economically justified assuming support of fixed and variable costs.

2.14 Recommendations (Cont'd.)

Given these constraints, but recognizing that there may be ancillary benefits in the broader context for such a project, UI is anxious to cooperate to the extent possible consistent with its anticipated long-term needs. Toward this end UI would be willing to consider further the desirability of making available the facilities at Steel Point Station for conversion to a coal gasification combined cycle system if adequate governmental, regulatory and financial support for such a project were forthcoming.

CHART I


STEEL POINT STATION
BRIDGEPORT HARBOR STATION
PEQUONNOCK



NORTH
EMPTY BARGE 850.57'
FUEL BARGE
CLAM SHELL CRANE
TRANSMISSION TOWER
CONCRETE DIKE WALL
OIL STORAGE TANKS
FUEL OIL TRANSFER HOUSE
AUX. WATER SUPPLY
WATER TREATMENT
SULFUR SASIFICATION
SULFUR RECOVERY
WASTE TREATMENT
ACID GAS REMOVAL
COAL PREPARATION
GASIFICATION HEAT RECOVERY PARTICULATE REMOVAL
GAS TURBINE & HRSG
COAL PILE
COOLING TOWER
BRIDGEPORT HARBOR
BULKHEAD
3 STORAGE HOUSES
OIL STORAGE TANKS
OIL SERVICE TANK
CONCRETE DIKE WALL
FIRE HOUSE
STORAGE HOUSE
CHEMICAL STORAGE HS.
ASH SILO
CHART II
FENCE
SEWAGE VAULT
SERVICE BUILDING
METER HOUSE
SUBSTATION SWITCH HOUSE
FENCE
PARKING AREA
STRATFORD AVENUE
STEEL POINT STATION
PUMP HOUSE
METER HOUSE
GATE HOUSE
STEEL POINT STATION
PRELIMINARY PLOT PLAN
UNITED ILLUMINATING CO
NEW HAVEN, CONN
Dravo
7073-200-1
"D"

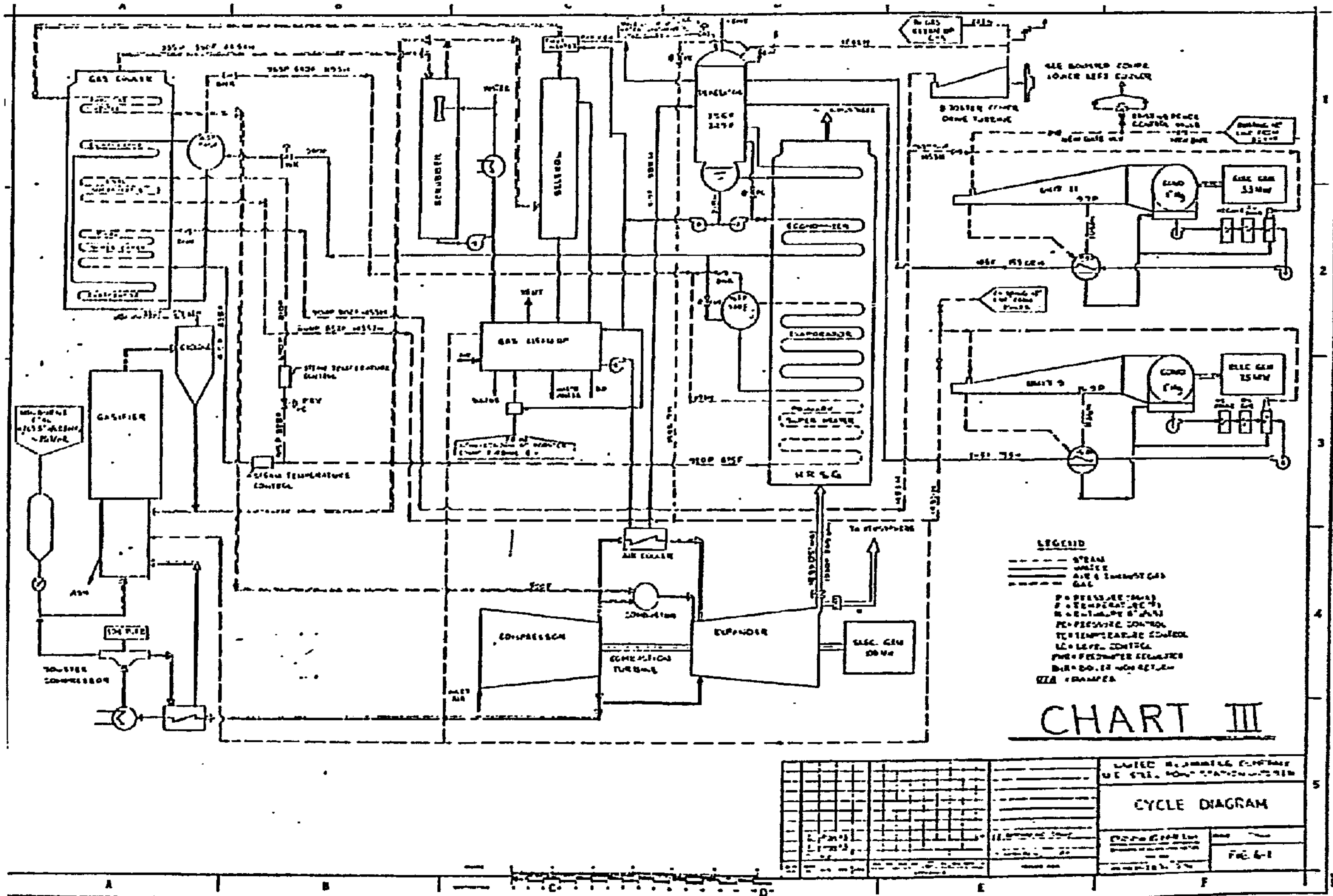
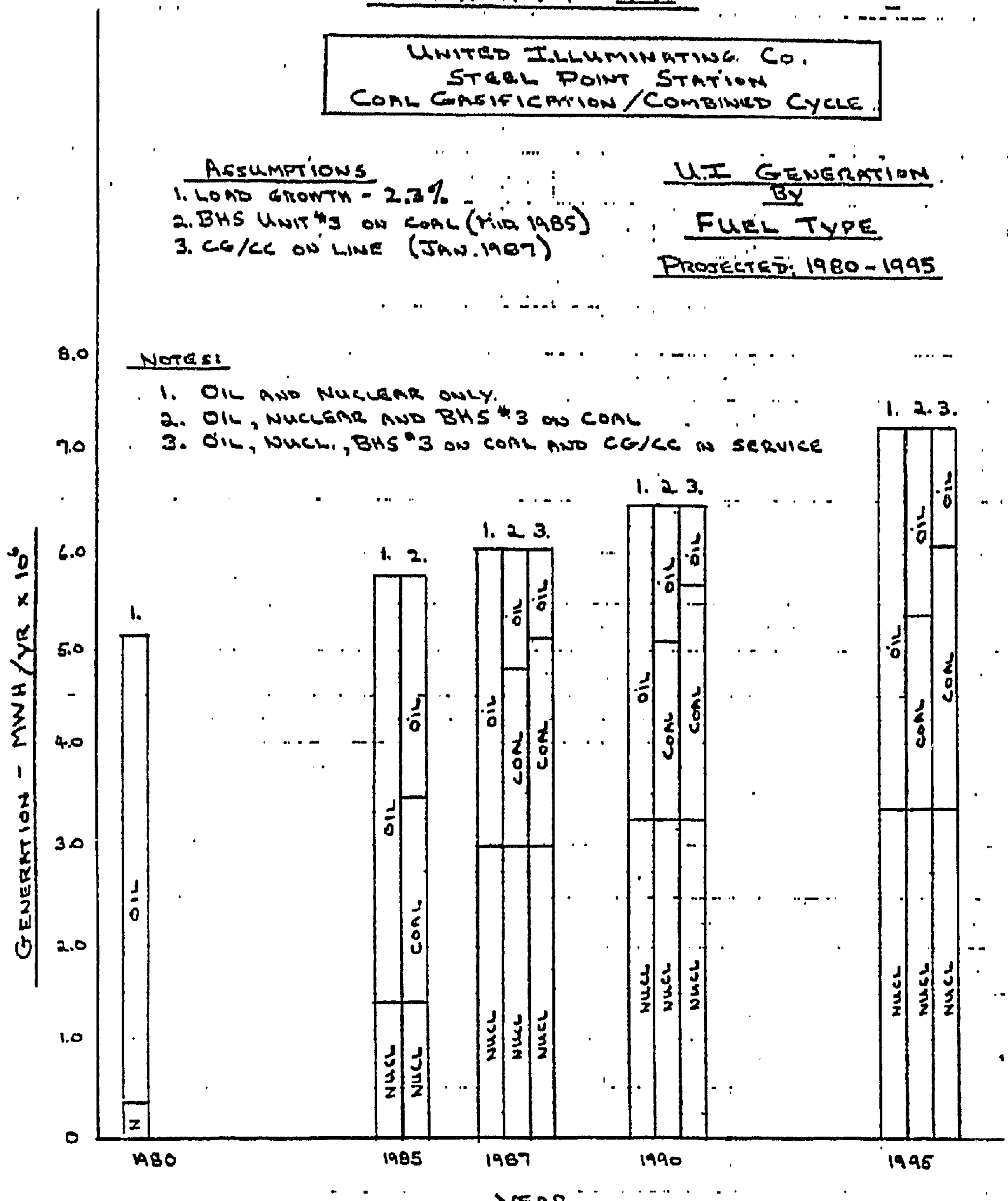
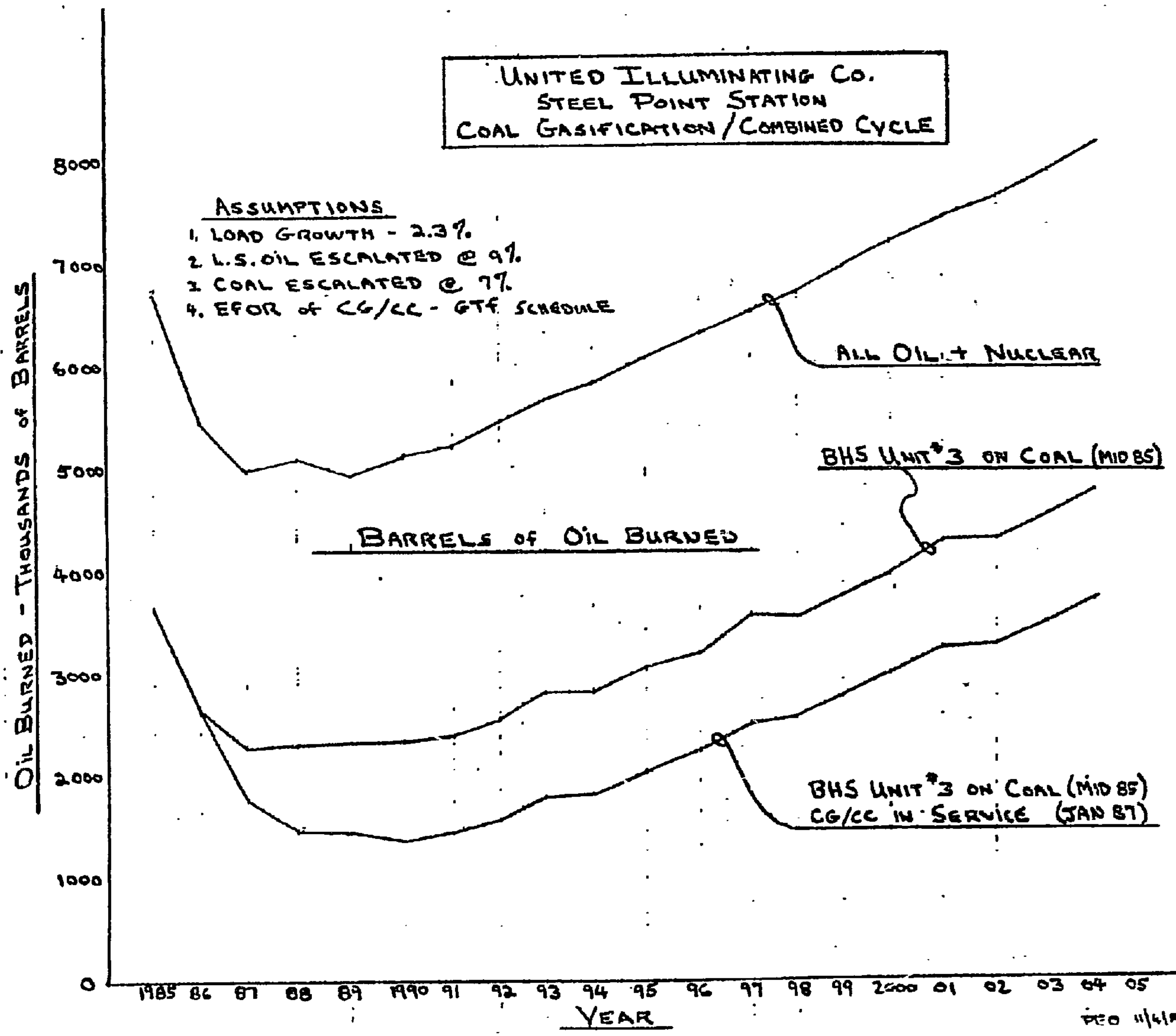

GAS COOLER
GASIFIER
CYCLONE
ASH
BOOSTER COMPRESSOR
SCRUBBER
WATER
GAS CLEANUP
VENT
STEAM TEMPERATURE CONTROL
AIR COOLER
COMBUSTOR
COMPRESSOR
COMBUSTION TURBINE
EXPANDER
ELEC. GEN
TO ATMOSPHERE
ECONOMIZER
EVAPORATOR
SUPER HEATER
HRSG
UNIT 11
UNIT 9
COND
ELEC GEN
LEGEND
STEAM
WATER
CHART III
CYCLE DIAGRAM
FIG. 6-1

CHART IV



PGO 11-4-80

CHART V



UNITED ILLUMINATING CO.
STEEL POINT STATION
COAL GASIFICATION / COMBINED CYCLE
ASSUMPTIONS
1. LOAD GROWTH - 2.3%
2. L.S. OIL ESCALATED @ 9%
3. COAL ESCALATED @ 7%
4. EFOR of CG/CC - GTF SCHEDULE
ALL OIL + NUCLEAR
BHS UNIT #3 ON COAL (MID 85)
BARRELS of OIL BURNED
BHS UNIT #3 ON COAL (MID 85)
CG/CC IN SERVICE (JAN 87)
OIL BURNED - THOUSANDS of BARRELS
8000
7000
6000
5000
4000
3000
2000
1000
0
1985
86
87
88
89
1990
91
92
93
94
95
96
97
98
99
2000
01
02
03
04
05
YEAR
PEO 11/4/80

CHART VI

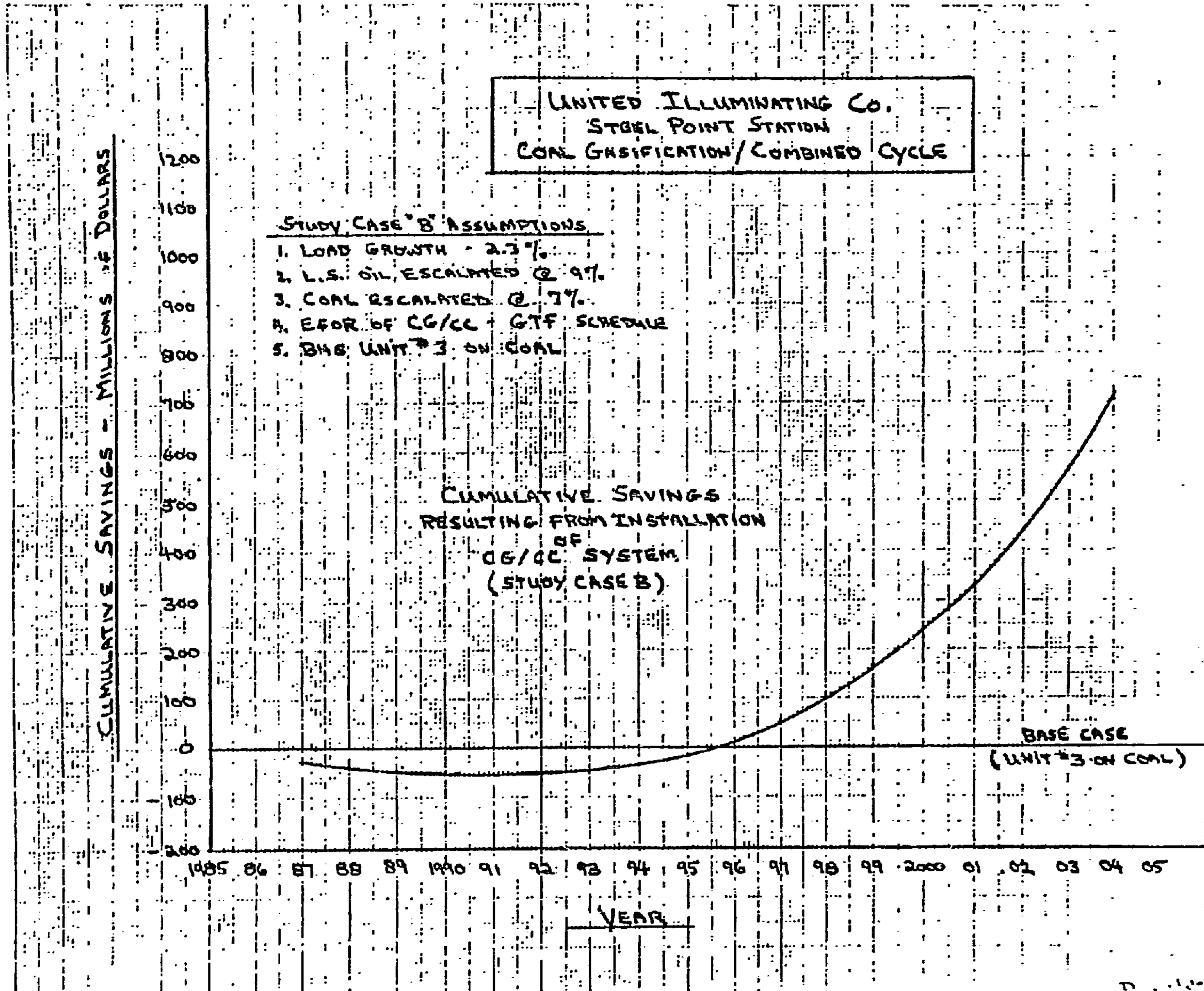
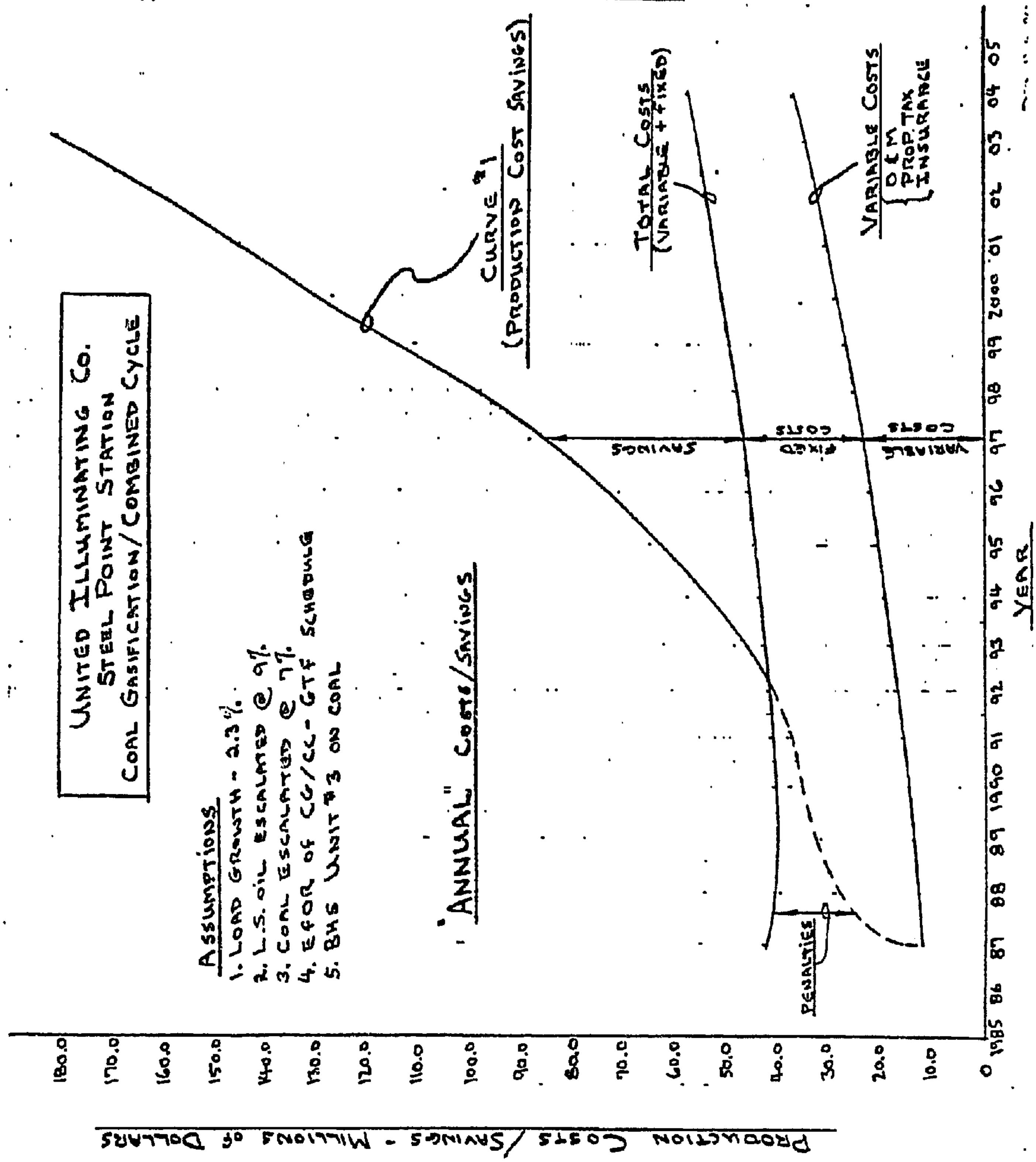
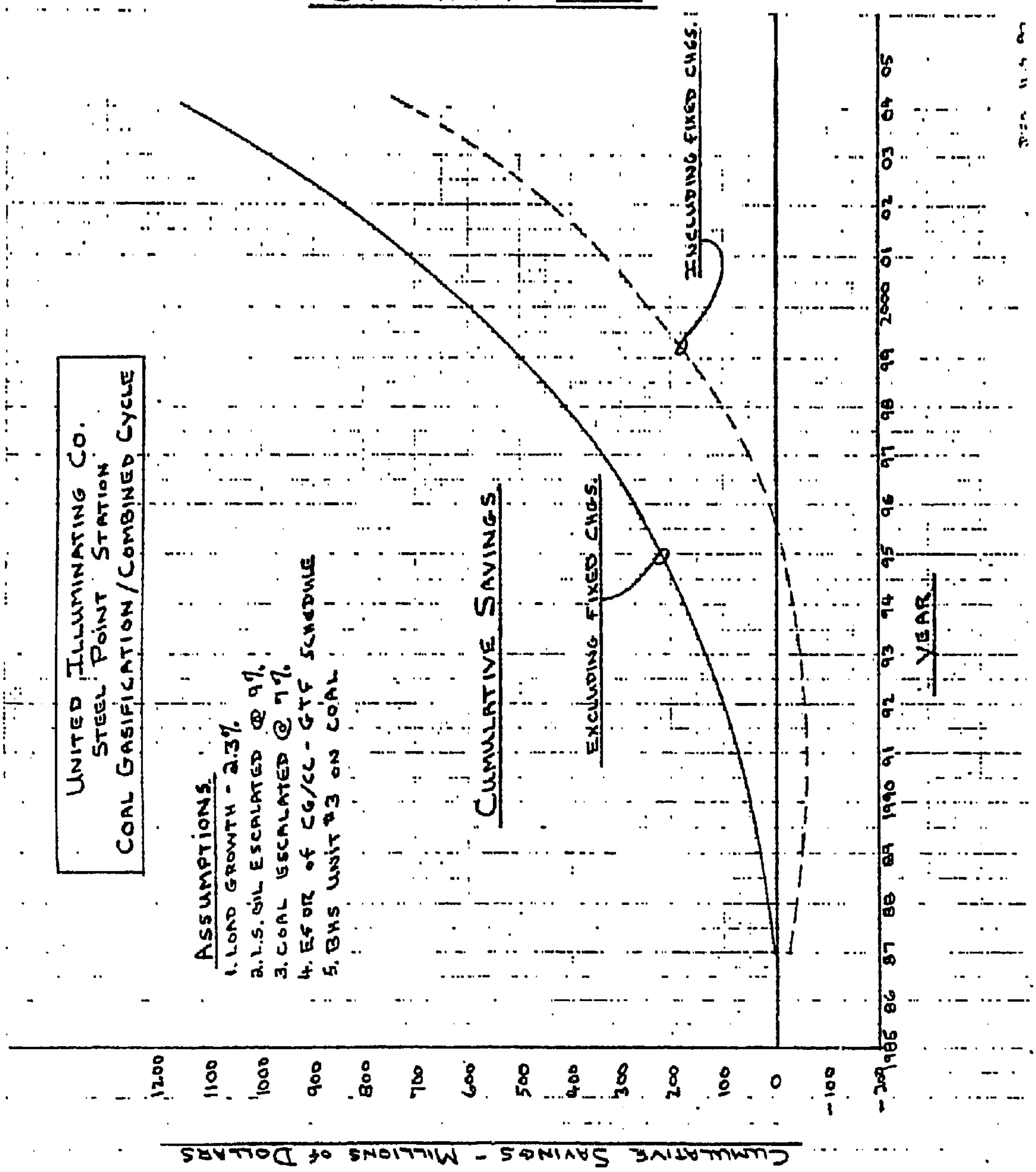

UNITED ILLUMINATING CO.
STEEL POINT STATION
COAL GASIFICATION/COMBINED CYCLE
STUDY CASE "B" ASSUMPTIONS
1. LOAD GROWTH - 2.3%
2. L.S. OIL ESCALATED @ 9%
3. COAL ESCALATED @ 7%
4. EFOR OF CG/CC + GTF SCHEDULE
5. BAS UNIT #3 ON COAL
CUMULATIVE SAVINGS
RESULTING FROM INSTALLATION
OF
CG/CC SYSTEM
(STUDY CASE B)
BASE CASE
(UNIT #3 ON COAL)
CUMULATIVE SAVINGS - MILLIONS OF DOLLARS
1200
1100
1000
900
800
700
600
500
400
300
200
100
0
-100
-200
1985
86
87
88
89
1990
91
92
93
94
95
96
97
98
99
2000
01
02
03
04
05
YEAR

CHART VII



United Illuminating Co.
Steel Point Station
Coal Gasification/Combined Cycle
Assumptions
1. Load Growth - 2.3%
2. L.S. Oil Escalated @ 9%
3. Coal Escalated @ 7%
4. EFOR of CG/CC-GTF Schedule
5. BHS Unit #3 on Coal
"Annual" Costs/Savings
Curve #1
(Production Cost Savings)
Total Costs
(Variable + Fixed)
Variable Costs
O&M
Prop. Tax
Insurance
Savings
Fixed Costs
Variable Costs
Penalties
Year
1985 86 87 88 89 1990 91 92 93 94 95 96 97 98 99 2000 01 02 03 04 05
Production Costs/Savings - Millions of Dollars
0 10.0 20.0 30.0 40.0 50.0 60.0 70.0 80.0 90.0 100.0 110.0 120.0 130.0 140.0 150.0 160.0 170.0 180.0

CHART VIII


United Illuminating Co.
Steel Point Station
Coal Gasification/Combined Cycle
Assumptions
1. Load Growth - 2.3%
2. L.S. Oil Escalated @ 9%
3. Coal Escalated @ 7%
4. EF OR of CG/CC - GTF Schedule
5. BHS Unit #3 on Coal
Cumulative Savings
Excluding Fixed Chgs.
Including Fixed Chgs.
Year
1985 86 87 88 89 1990 91 92 93 94 95 96 97 98 99 2000 01 02 03 04 05
Cumulative Savings - Millions of Dollars
1200 1100 1000 900 800 700 600 500 400 300 200 100 0 -100 -200

3.0 COAL GASIFICATION COMBINED CYCLE SYSTEM

Introduction

A coal gasification system has been proposed to replace the fuel oil fired steam generators in the repowering of the Steel Point Station of the United Illuminating Company. A new 108 MW gas fired combustion turbine-generator will be combined with the existing 30 MW #11 steam turbine generator and the existing 25 MW #9 steam turbine generator to produce a total of 169 MW of electric power of which 161 MW is available. Steam for the existing #11 and #9 steam turbine would be produced in two new heat exchangers, one as part of the Westinghouse Coal Gasification System (Gas Cooler) and the other in the exhaust system of the gas fired combustion turbine (Heat Recovery Steam Generator). This section summarizes the processes and equipment required to gasify the coal, clean up the low Btu gas produced, generate the steam needed for #9 and #11 steam turbines, treat the boiler feed water and the waste water, provide the cooling water for the new portions of the plant and other auxiliaries such as coal receipt and handling, coal preparation and drying, etc.

A conceptual block plot plan showing the estimated areas needed for the various operations has been prepared and is as shown on Dravo Drawing 7073-200-1. The various areas have been arranged so as to have the steam generators as close as possible to the #9 and #11 steam turbines, the electrical output from the combustion turbine generator set convenient to its tie in point and to establish a fuel gas flow path that will have a minimum length consistent with the process operations used to clean the gas. We feel that the areas shown are conservative, and that they can probably be made more compact when detailed design is started. This would allow for the installation of a larger coal pile at Steel Point Station.

An evaluation of potential coal gasifiers that might be used for this application that was made by Dravo Engineers and Constructors resulted in the selection of the Westinghouse Coal Gasification System. A copy of the report written for this study is included as Appendix A.

3.1 Overall System Description

The Overall Block Flow Diagram (Drawing 7073-100-001) illustrates the proposed plant.

Bituminous coal from the Winburne, PA mine of the General Coal Company is shipped by rail to Port Reading, New Jersey. Here the coal is transferred to barges for shipment to the plant site in Bridgeport, CT.

The coal can be delivered either directly to the Steel Point Station or to Bridgeport Harbor Station where it will be stockpiled or fed into the system as shown on Drawings #101-001 and 101-002. These stations are located on opposite shores of Bridgeport Harbor. Long term storage will be provided for at the Bridgeport Harbor Station from which coal would be reloaded into barges via a new conveyor system for transfer to Steel Point Station as the need arises.

The coal is dried, if necessary, prior to being crushed to a size required for stable fluidzation in the gasifiers. The crushed coal is stored in four bins, one provided per gasifier.

The crushed coal is transferred on demand by conveyor to elevated surge bins. These bins discharge into feed coal lockhoppers in which the coal is pressurized and pneumatically fed into the gasifiers, where it reacts with steam and air, producing a fuel gas with a higher heating value of 146 BTU/SCF. Bottom ash is removed via ash lock hopper. The majority of the solids entrained in the raw fuel gas are removed in multicyclones and pneumatically reinjected into the gasifier.

The gas, at 1850°F and 340 psig, then passes through parallel heat recovery systems where a portion of its sensible heat content is recovered by generating steam, superheating steam, and reheating purified fuel gas. At this point, the system reverts to a single train. The fuel gas proceeds to a series of clean-up steps to transform it into a clean gas suitable for combusting in the turbine generator.

Final particulate removal is the first clean-up step and is achieved in a venturi scrubber. The solids are removed in slurry form and are hydrocloned, with the solids concentrate sent to waste treatment for disposal. The particulate-free gas is reheated prior to entering the COS hydrolyzer, in which the bulk of the COS is converted to H_2S, a form in which sulfur is more readily absorbed from the fuel gas stream.

p

3.1 Overall System Description (Cont'd.)

Ammonia is the next contaminant removed from the fuel gas. The ammonia, along with other gases, including some H_2S, is removed by absorption in water. These gases are stripped and fed to a partial Phosam system in which the ammonia is absorbed in a phoshoric acid solution. The ammonia is stripped out of the acid solution and incinerated.

The fuel gas flows to a Selexol system where the sulfur gases are removed. The fuel gas can now be fed to the combustion turbine. The sulfur gases, along with those from the Phosam system, are fed to the Claus plant where the sulfur is recovered in its elemental form.

A portion of the clean fuel gas is consumed in the Claus plant incinerator, while another side stream is used as fuel for coal drying on an intermittent basis. The remainder of the fuel gas is heated in the heat recovery systems and then combusted in the combustion turbine. The hot, pressurized combustion products pass through the expander section and exit at 25" WG and 1030°F. Part of the power produced from this expansion compresses air required by the turbine combustor and for conveying the coal feed into the gasifiers, and as a reactant in the gasifiers. The remaining power is recovered as 108 MW of electricity.

The hot combustion products are cooled by raising steam in a heat recovery unit. This steam is split for #9 and #11 units and both streams are superheated in the aforementioned heat recovery systems. Steam is fed to the existing #9 steam power generator at 625 psig and 850°F and exhausted at 1" Hg absolute pressure, producing 30 MW of electric power. The other steam stream is fed to the exisitng #11 steam power generator at 850 psig and 900°F and exhausted at 1" Hg absolute pressure, producing another 31 MW* of electric power. The condensate from these turbines is returned to the deaerator.

Other processes and equipment, although not part of the direct process flowscheme, are required for an integrated plant. These include the following:

SCOT Plant - Treats the Claus plant tailgas by reducing SO_2 to H_2S and recycling it to the front end of the Claus plant.

Instrument/plant air compressors - provides dry, compressed air to instruments and other users.

Primary water treatment - none will be required since city water is being purchased.

Demineralization - purifies city water for use as high pressure boiler feed water.

*See Discussion - Section 3.2.5.1

3.1 Overall System Description (Cont'd.)

Cooling water system - supplies cooling water to the process.

Wastewater treatment - provides treatment for all plant wastewater streams.

Fire Protection - an in-plant system is provided, in addition, the city firewater system serves as backup.

Flare - a ground flare provides the means for safe disposal of off-spec gases and gases vented in emergency conditions.

3.2 System Components

3.2.1 Coal Gasification

Reference: PFD-103-001

Feed Coal Surge Bins (103-35001-1, 4) charge coal into Gasifier Systems (103-33001-1, 4). The coal flows by gravity into the upper Feed Coal Lock Hoppers. Once loaded, these Hoppers are pressurized by gas injection. The coal is transferred into the lower Feed Coal Lock Hoppers, from which transport air pneumatically conveys the coal into the Gasifiers. When the upper Hoppers are emptied, the pressurizing gas is vented through the filters located on the Sized Coal Storage Bins (102-34001-1, 4). This step minimizes coal fines discharge to the atmosphere. The coal feeding sequence described above is repeated. The source of the transport air is described in section 3.2.3 of this report.

The coal is fed into the base of the Gasifiers where it is diluted with internally recycling char. This dilution prevents agglomeration which occurs until the coal is devolatized. Steam and air, the remaining reactants, are injected at several locations to ensure proper fluidization. As the coal reacts, its ash content increases, causing these particles to soften and agglomerate. This increases their density and they fall out of the fluidized bed. Gas is injected countercurrent to the ash flow to recover the heat content of the ash before the particles are discharged from the Gasifiers.

The ash agglomerates are fed into the upper Ash Removal Lock Hoppers. Once full, these Hoppers are depressurized by venting trapped gases to the incinerator (109-47003) where they are combusted before being vented to the atmosphere. The ash is then discharged into the lower Ash Removal Lock Hoppers from where they are transferred to Ash Bunkers (103-34001-1, 2) by Ash Conveyor System (103-43001). The ash is removed from the Ash Bunkers and disposed of off-site. The raw fuel gas exits the disentrainment section of the Gasifiers at 1850°F and 340 psig. The majority of the solids entrained in this gas are removed in the Gasifier Multi-Cyclones. The fuel gas flows from the Multi-Cyclones to the Heat Recovery Systems (104-44001-1, 4).

The char particulates removed in the Multi-Cyclones are cooled before being recycled to the Gasifiers. The particulates are fluidized in the base of the Multi-Cyclones, where they heat BFW circulating in coils within the Multi-Cyclones. The heated BFW flows to the Heat Recovery Systems. The cooled

3.2.1 Coal Gasification (Cont'd.)

particulates drop into the Recycle Solids Lock Hoppers from where they are pneumatically reinjected into the Gasifiers by recycle gas provided by the Recycle Booster Compressor (105-42001-1, 2).

3.2.2 Fuel Gas Clean-Up

3.2.2.1 Particulate Removal

Reference: PFD 104-001

Cooled fuel gas leaves the Heat Recovery Systems (104-44001-1, 4) at 350°F and is headered before flowing through the shell side of Interchanger (104-31001). The fuel gas exits from this unit at 290°F and enters the Particulate Scrubber (104-45001) where it is water-scrubbed for particulate removal. The particulate loading of the fuel gas must be reduced to protect the Expander section of the Combustion Turbine (107-47001) from erosive damage. Three phases flow out of the Scrubber venturi and into the Scrubber separator in which the fuel gas is separated from a water-solids slurry. Water carryover is minimized by passing the gas through a mist eliminator installed in the top of the Scrubber separator. The scrubbed fuel gas passes through the tube side of the Interchanger where it is reheated to 297°F before entering the COS Hydrolyzer (104-35001).

The slurry is pumped out of the Scrubber separator by Recycle Pump (104-41001-1, 2) and recycled to the Scrubber venturi. Before reentering the venturi, the slurry flows through the Hydroclone (104-45002-1, 2). The collected particulates are removed in the Hydroclone bottoms as a 30% sludge and discharged into a Char Letdown Tank (116-35003) shown on PFD 116-003. Treatment of this sludge is discussed in Section 3.2.6 of this report.

p

3.2.2.2 Ammonia Removal

Reference: PFD 105-001

The fuel gas is cooled from 286°F to 240°F as it passes through the shell side of the Scrubber Interchanger (105-31001). The gas then flows upward in the Ammonia Scrubber (105-32001) in which its ammonia content, along with some of its H_2S and CO_2, is absorbed in a countercurrent flow of water. The ammonia must be removed before the fuel gas is processed in the Selexol System (106-47001). If not removed, part of the ammonia would end up in the Claus Plant (109-47001) feed, causing the Sulfur Condensers to plug with ammonia salts.

The ammonia free gas exits the top of the Scrubber at 110°F and 305 psig. A sidestream is compressed in the Recycle Booster Compressor (105-42001-1, 2) and transports recycle char into the Gasifiers, while the main stream flows to the Selexol System.

The Ammonia Recycle Pump (105-41001-1, 2) circulates recycle water from the Scrubber base, through the shell side of the Scrubber Recycle Cooler (105-31002) in which the recycle water temperature is reduced from 150°F, and then into the top of the Scrubber. A bleed stream is taken out of the Scrubber base and heated to 205°F in the Scrubber Interchanger before being reduced in pressure and fed into the top of the Ammonia Stripper (105-32002). The absorbed NH_3, H_2S, and CO_2 are stripped out by live steam injected at the base of the column. The Stripper Pump (105-41002-1, 2) removes the lean water from the Stripper. This water is cooled from 239°F to 139°F in the Stripper Bottoms Cooler (105-31003) prior to being split into three streams. The bulk of this water flows through the shell side of the Stripper Recycle Cooler (105-31004) where it is cooled to 105°F before entering the top of the Ammonia Scrubber. A second stream serves as make-up water to the particulate removal system located in Area 4. The third stream is fed to the Stripped Condensate Surge Tank (116-35002). Treatment of this stream is discussed in Section 3.2.6 of this report.

The stripped gases exit from the top of the Ammonia Stripper and are cooled in the Stripper Condenser (105-44001). The water condensed from the gases in

3.2.2.2 Ammonia Removal (Cont'd.)

cooling is separated in the Knock-Out Pot (105-35001) and returned to the Stripper as reflux. The remaining gases enter the partial Phosam (105-47001) system at 150°F and 6.8 psig.

The gases enter the base of the Phosam Abosrber and are contacted by a countercurrent flow of phosphoric acid solution. The ammonia is absorbed in this solution, and the H_2S and CO_2 exit from the top of the Absorber and are piped to the Claus Plant. The ammonia rich solution is pumped to the top of the Phosam Stripper in which the ammonia is stripped from the acid solution. The regenerated solution is recycled to the Absorber. The ammonia exits from the top of the Stripper and flows to the Incinerator (109-47003), where it is combusted in burners designed to minimize NO_x formation. At the elevated temperatures experienced during combustion, ammonia dissociates into Nitrogen and Hydrogen radicals. The majority of the Nitrogen recombines as molecular Nitrogen while the remainder is combusted to NO_x. The Hydrogen is combusted to water.

3.2.2.3 Acid Gas Removal

References: PFD's 104-001, 106-001

After the fuel gas is treated for particulate removal, it is heated to a minimum of 50°F above its dew point in an Interchanger (104-31001). The gas then enters the COS Hydolyzer (104-35001), a fixed bed catalytic reactor in which approximately 90% of its COS content is converted into H_2S by the reaction.

$$COS + H_2O \rightarrow H_2S + CO_2$$

This conversion is necessary since COS would not be adequately removed in the Selexol System (106-47001) to protect the fuel gas users from corrosive damage and to satisfy environmental regulations. The unconverted COS is oxidized to CO_2 and SO_2.

The fuel gas, after being cleansed of ammonia in Area 5, Ammonia Removal, enters the base of the Selexol System Absorber at 110°F and 305 psig. Selexol solvent absorbs most of the H_2S and some of the COS and CO_2 as it passes countercurrent to the gas. The purified gas exits at the Absorber top and a sidestream is extracted for use in the SCOT Unit (109-47002). The main stream is heated to 205°F as it passes through the shell side of the Fuel Heater (106-31001) before flowing to the Heat Recovery Systems (104-44101-1, 4) for further heating. A side stream is removed intermittently at this point for use as furnace fuel in the Coal Drying and Sizing System (102-47001) when the total moisture content of the coal exceeds 6%.

Rich solvent exits the Absorber bottom and passes through a Power Recovery Turbine before being flashed. A portion of the semi-regenerated solvent is then pumped and cooled before reentering the Absorber at an intermediate level, while the remainder is fed to the Stripper. In the Stripper, the remaining acid gases are removed by steam stripping. The lean solvent is pumped from the Stripper bottom and cooled before entering the top of the Absorber to continue the absorption process. The acid gases exiting the top of the Stripper are combined with those from the flash drum and are fed to the Claus Plant (109-47001).

3.2.2.3 Acid Gas Removal (Cont'd.)

A small sour water stream, which results from condensation in the Stripper, is fed to Area 16, Waste treatment. Treatment of this stream is discussed in Section 3.2.6 of this report.

3.2.2.4 Sulfur Recovery

References: PFD's 109-001, 109-002

H_2S - containing gases from the Selexol System (106-47001), the Partial Phosam System (105-47001), and recycle gas from the SCOT Unit (109-47002) enter the Claus Plant (109-47001) by passing through a Knock-Out Pot where any entrained liquids are removed. These gases then enter the Sulfur Burner, where they are mixed with sufficient air to oxidize one third of the H_2S to SO_2. The combustion products and the remaining H_2S enter the Reaction Furnace where sufficient residence time is provided for the Claus reactions to come to equilibrium, the Claus reactions are expressed as:

$$H_2S + 3/2\ O_2 \rightarrow SO_2 + H_2O$$
$$2H_2S + SO_2 \rightarrow 3S + 2H_2O$$

Effluent gas from the Reactions Furnace is cooled in a Waste Heat Boiler where 65 psig steam is generated. The gas leaving this Boiler flows to a Sulfur Condenser where the sulfur formed in the furnace is removed and routed to the Liquid Sulfur Rundown Tank. The gas flowing through the Condenser is cooled by generating additional steam.

The gas is passed through a series of three Catalytic Reactors to complete the conversion of H_2S and SO_2 to elemental sulfur. Effluent gas from the first Sulfur Condensor must be reheated before entering the first Catalytic Reactor. This is accomplished by combining it with a small side stream of hot gas from the Waste Heat Boiler.

The conversion to elemental sulfur continues in the Catalytic Reactors, and the sulfur formed is removed in Condensers located between Reactors. Gases to the second and third reactors are reheated by indirect heat exchange with hot gases leaving the preceding Reactor. Any entrained sulfur in the Tailgas leaving the last Condenser is removed in a Knock-Out Drum.

The Claus plant tailgas exiting this Drum is too high in sulfur to be vented to the atmosphere. Therefore, this tailgas is piped to the SCOT Unit where its SO_2 is catalytically converted to H_2S by the reaction:

$$SO_2 + 3H_2 \rightarrow H_2S + 2H_2O$$

3.2.2.4 Sulfur Recovery (Cont'd.)

The source of this H_2 is a bleed stream pulled off of the outlet of the Selexol Absorber. A portion of this bleed is combusted in the Feed Heater to raise the tailgas temperature to 575°F, the temperature required for the above reaction to proceed.

The Reactor exit gas is cooled in passing through a Waste Heat Boiler in which 65 psig steam is generated, and then further cooled to 100°F by water in a Direct Quench Cooler. Sour water drawn off from the quench cooling circuit is pumped to Area 16, Waste Treatment, for treatment.

The quenched gas enters the bottom of the SCOT Absorber while the amine solvent is pumped to the top. The solvent absorbs nearly all the H_2S and some CO_2 as it flows countercurrent to the gas. The Absorber overheads, containing the unabsorbed H_2S, are preheated by steam in an Incinerator Feed Heater (109-31001) before being combusted in the Incinerator (109-47003). The Incinerator tailgas is vented to the atmosphere.

The rich solvent, containing the absorbed acid gases, is pumped from the Absorber bottom, heated by interchange with hot lean solvent from the SCOT Stripper, and flows to the Stripper for solvent regeneration. In the Stripper the absorption reaction is reversed by heat supplied to a steam-heated Reboiler, and the acid gases are driven overhead. Water vapor is condensed, separated from the gases, and refluxed to the Stripper while the acid gases are recycled to the Claus Plant.

Hot lean solution is pumped from the Stripper bottom and cooled by interchange with the cool rich solution. It is further cooled in a water cooled Exchanger and returned to the top of the Absorber to continue the absorption sequence.

In addition to the SCOT Unit tailgas, vents from the Ash Removal Lock Hoppers in Area 3, Gasification, and ammonia vapors from the Partial Phosam are combusted in the Incinerator. Fuel gas from the Selexol Absorber serves as incinerator fuel

3.2.2.4 Sulfur Recovery (Cont'd.)

after being preheated by steam in a Fuel Gas Heater (109-31002). Combustion air is provided by the Incinerator Blower (109-42001). This air is preheated in an Economizer prior to being fed to the burners.

Blowdown from the Boilers in the Claus Plant and the SCOT Unit are piped to Area 16, Waste Treatment, for treatment.

The liquid sulfur recovered in the Claus Plant is pumped to solidification pits to harden before being loaded onto trucks by the Sulfur Loader (109-49001) and shipped to off-site disposal or to a purchaser.

3.2.3 Combustion Turbine

Reference: PFD 107-001

The Combustion Turbine (107-47001) is a dual function machine in which hot combustion gases are expanded to generate electric power while air is simultaneously compressed for in-plant process requirements.

Clean, preheated fuel gas enters the Combustor section of the Turbine at 500°F and 300 psig and is combined with a portion of the air compressed in the Compressor Section. The mixed gases are then combusted. The hot, pressurized combustion gases are tempered with additional compressed air as they enter the Expander Section. BFW flowing through an Air Cooler helps control the tempering operation. The combined gas stream exits the Expander Section at 1030°F and 25" WG and flows to the Heat Recovery Unit (108-44001) where it is cooled as it generates steam before being vented to the atmosphere.

The power recovered in the Expander Section that is not consumed by the Compressor Section is converted to approximately 108 MW of product electrical energy.

In addition to the combustion and tempering air flows described above, air is also compressed for use as a reactant in the Gasifier Systems (103-33001-1, 4) and for the pneumatic feeding of coal into the Gasifiers. The air for these services exits the Compressor Section at 300 psig. This air must be further compressed above the Gasifier operating pressure of 340 psig. This is accomplished in an Air Booster Compressor (107-42001). 900°F, 850 psig steam from the Heat Recovery Systems (104-44001-1, 4) provides power to the Compressors' Turbine drive. The steam is exhausted at 85 psig and piped to various process users.

The reaction and transport air is cooled before being compressed in the Booster Compressor. This cooling is accomplished in two stages. The air is cooled from 718°F to 320°F as it passes through the shell side of the Gasifier Air Interchanger (107-31001) and is further cooled to 100°F in the water-cooled Booster Compressor Precooler (107-31002). The air exits the Booster Compressor at 253°F and 395 psig. Transport air flows directly to the discharge of the Feed Coal Lock Hoppers where it picks up the coal feed to the Gasifiers, while the reaction air is first preheated to 696°F as it flows through the tube side of the Gasifier Air Interchanger and then proceeds to the Gasifiers.

3.2.4 Heat Recovery

References: PFD's 104-001, 108-001

The hot exhaust gases from the Combustion Turbine (107-47001) are cooled in the Heat Recovery Unit (108-44001) before being vented to the atmosphere. Additional heat is recovered from the hot raw fuel gas in the Heat Recovery Systems (104-44001-1, 4). This heat energy would be lost if not recovered before the fuel gas is scrubbed for particulate removal. These two heat sources combine to generate process steam and the two levels of turbine steam required by Existing Turbine Generator #11 (111-47001) and Existing Turbine Generator #9 (112-47001).

A Deaerator (108-45001) functions as both a degasser and as a reservoir of hot BFW. The Secondary BFW Pump (108-41001-1, 2) circulates BFW to Waste Heat Boilers located in the Claus Plant (109-47001) and SCOT Unit (109-47002), to reduce the superheat in the steam feed to the Gasifiers, to the tempering Air Cooler that is part of the Combustion Turbine, and to the chemical makeup section of the Selexol System (106-47001). A Primary BFW Pump (108-41002-1, 2) pumps BFW to the Heat Recovery Unit where it is first heated to near boiling. The BFW exits the Unit and is split into two streams. One stream discharges into the Units' Steam Drum, while the second flows to the Gasifier Multi-Cyclones where it extracts heat from char that is to be recycled to the Gasifiers. This BFW then flows to the Heat Recovery Systems (104-44001-1, 4) where additional heat is picked up and process steam is generated. Any steam in excess of process needs is piped to the vapor discharge of the Heat Recovery Unit Steam Drum.

The BFW fed directly to this Steam Drum is transformed into steam in its next pass through the Unit. This saturated steam then combines with the excess steam mentioned above and reenters the Unit and is superheated. The steam flow is then split to produce the proper pressures and flow rates required by the two Existing Turbine Generators. The two streams then pass through separate Desuperheaters where their temperatures are adjusted to ensure that the temperature of the steam fed to the Existing Turbine Generators does not exceed their design values. Desuperheating BFW is provided by the Primary BFW Pump. The two vapor streams then flow through separate tube banks in the Hear Recovery Systems. One stream exits the Systems at 850°F and 625 psig and, after a side stream used as reaction steam in the Gasifiers is removed, flows to Existing Turbine Generator #9, where it is condensed at 1" Hg, generating 30 MW of electric power in the process. The second stream exits the Systems at 900°F and 850 psig and after a side stream used to drive the Air Booster Compressor (107-42001) is removed, flows to Existing Turbine Generator #11, where it is condensed at 1" Hg, generating 31 MW of electric power in the process. The condensate from both Generators is recycled to the Deaerator.

3.2.4 Heat Recovery (Cont'd.)

Blowdowns from the Heat Recovery Unit and from the Heat Recovery Systems are routed to Area 16, Waste Treatment, for treatment.

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3.2.5 Steam Turbine

3.2.5.1 #11 Unit

Reference: PFD 111-001

900°F, 850 psig superheated steam from the Heat Recovery Systems (104-44001-1, 4) flows to the Existing Turbine Generator #11 (111-47001), where it is expanded to 1" Hg absolute pressure while producing 31 MW of electric power. The exhaust steam is condensed in a water cooled Condenser and recycled to the Deaerator (108-45001).

Prior to reaching the Deaerator, the recovered condensate:

a) is pumped through the Hydrogen Cooler, where it extracts heat from the hydrogen used to cool the Generator.
b) flows through the Oil Cooler, where it cools the Generator lubricating oil.
c) recovers heat from the Air Ejector exhaust.
d) is further heated by extracted steam in one feed water heater.

Motive Ejector steam is obtained from a slip-stream of the Turbine feed. The heating steam is fed to the Condenser, where it is recovered as condensate. Uncondensed vapors from the Air Ejector are vented to the atmosphere.

Steam leakoff from the Turbine is cascaded to the condenser.

Excess steam that cannot be used by this Turbine Generator is produced during rated operations. There are a number of options available for dealing with this steam, including the following:

a) it can be vented to the atmosphere, its heat content lost and the demineralized water replaced.
b) it can be condensed and the demineralized water recovered, its heat content lost.
c) it can be used as turbine drive steam within the plant, increasing the electric power available for export.
d) it can be eliminated by cutting back on the fuel gas to the Combustion Turbine (107-47001).
e) it can be injected into the Combustion Turbine for more power and No_x Control.
f) it can be a source of heat for cogeneration.

3.2.5 Steam Turbine (Cont'd.)

Each option has its advantages and disadvantages. A decision on this matter would require further study. Option "b" was assumed for purposes of development of the process design basis. U.I., however, adjusted these figures slightly to take advantage of the excess steam by increasing No. 11 Unit output consistent with current operating levels (which slightly exceed General Electric's recommended loadings).

3.2.5 <u>Steam Turbine</u> (Cont'd.)

3.2.5.2 <u>#9 Unit</u>

Reference: PFD 112-001

850°F, 625 psig superheated steam from the Heat Recovery Systems (104-44001-1, 4) flows to the Existing Turbine Generator #9 (112-47001), where it is expanded to 1" Hg absolute pressure while producing 30 MW of electric power. The exhaust steam is condensed in a water cooled Condenser and recycled to the Deaerator (108-45001).

Prior to reaching the Deaerator, the recovered condensate:

a) is pumped through the Hydrogen Cooler, where it extracts heat from the hydrogen used to cool the Generator.
b) flows through the Oil Cooler, where it cools the Generator lubricating oil.
c) recovers heat from the Air Ejector exhaust.
d) is further heated by extracted steam in one feedwater heater.

Motive Ejector steam is obtained from a slip-stream of the Turbine feed. The heating steam is fed to the Condenser, where it is recovered as condensate. Uncondensed vapors from the Air Ejector are vented to the atmosphere.

Steam leakoff from the Turbine is piped directly to the Deaerator.

3.2.5 Steam Turbine (Cont'd.)

3.2.5.3 Discussion on the Use of Turbine Extractions

Existing turbine - generator Units 9 and 11 are presently arranged for regenerative feedwater heating. Steam is extracted from the turbine at several stages and supplied to feedwater heaters. Feedwater passing through the series of heaters is heated and delivered to the fuel-fired steam generating unit at relatively high temperature, in the order of 400°F, and a saving of fuel is accomplished. In the combined cycle, however, the object is to make use of gas turbine exhaust heat for production of steam. To do this with a maximum heat recovery and with no change in gas turbine fuel, a low feedwater temperature is required. The higher pressure extractions, therefore, are not used to heat the feedwater, instead the steam is allowed to flow through the turbine for production of additional kilowatts.

It should be noted that in the conventional fuel-fired steam generating unit, the flue gases leave the "economizer" section at 600 to 700°F, and are further cooled in the air preheater wherein air for combustion is heated. There would be no use for preheated air in the gas turbine of the combined cycle.

3.2.6 Water Treatment

References: PFD's 113-001, 114-001, 116-001 thru 006

The description of the water treatment facilities is divided into two sections - treatment of city water and treatment of plant wastewaters. City water is treated in Area 13 and 14; plant wastewaters are treated in Area 16.

City Water Treatment

City water is the water source for the coal gasification plant. It is consumed directly as potable water, pump flush and seal water, boiler blowdown quench water, and as make-up to the Cooling Tower (115-44001). Only city water to be used as Boiler Feed Water (BFW) is treated in-plant. This water is demineralized before it is fed to the plant boilers.

City water enters the Carbon Filter of the Demineralization System (114-47001) where any traces of organics and chlorine are removed, since these contaminants could foul the ion exchange resins.

The filtered water flows through a Cation Exchanger in which essentially all cations, such as calcium (Ca^{+2}) and magnesium (Mg^{+2}), are removed from the water and replaced by hydrogen ions, (H^{+}). Anions, such as bicarbonate (HCO_3^-) and sulfate (SO_4^{-2}), are next replaced by hydroxide ions (OH^-) in an Anion Exchanger. The water is now demineralized and is stored in the Demineralized Water Tank (114-34001). This Tank provides BFW surge in case of Demineralization System failure, loss of city water flow, or other supply interruption.

The Carbon Filter, Cation Exchanger, and Anion Exchanger are spared since they require periodic backwashing to reactivate them. Backwash of the Carbon Filters involves the pumping of organic and chlorine-free water upward through the carbon bed, in opposite direction to the normal process flow. This will release organics and chlorine trapped in the bed. The Cation Exchangers are backwashed with a dilute sulfuric acid solution. This process recharges the cation resins with hydrogen ions while removing the absorbed cations from the resin bed. The Anion Exchangers are backwashed with a dilute hydroxide ions while removing the absorbed anions from the resins beds.

These backwashes are pumped to the 225,000 gallon pond for storage and are then processed in the Steel Point Station Waste Water Treatment System (116-47002) where they are neutralized and the effluent clarified before being discharged to the river.

3.2.6 Water Treatment (Cont'd.)

The Distribution Pump (114-41002) provides demineralized backwash water to the Cation and Anion Exchangers. The Demineralized Water Pump (114-41001-1,2) feeds BFW to the Deaerator (108-45001) on a demand basis.

Waste Water Treatment

Coal pile runoff from the storage piles at both the Bridgeport Harbor Steel Point Stations will require treatment before being discharged from the plant. This treatment is provided by the Bridgeport Harbor Station Treatment System (116-47001) and by the Steel Point Station Treatment System. The runoff is neutralized with lime and aerated before being pumped to a Clarifier. The Clarifier bottoms, in which any solids precipitated in the neutralizing step will settle, are pumped through a Filter. The filtrate is recycled to the Clarifier, while the filter cake is disposed of off-site. The Clarifier overflow is discharged from the plant.

Stripped condensate from the Ammonia Removal area is quenched by city water and the mixture is stored in the Stripped Condensate Surge Tank (116-35002). This water cools the boiler blowdowns in the Blowdown Separators (116-45001, 116-45002, 116-45003, 116-45004). The combined blowdown/condensate from the Separators is collected in a Blowdown Surge Tank (116-35001). The Blowdown/Condensate Pumps (116-41001-3) feed this recovered water to the Cooling Tower for use as make-up.

To satisfy environmental regulations, Cooling Tower blowdown may have to be cooled before it is discharged from the plant. This is accomplished by passing it through the inner pipe of the double pipe unit Cooling Tower Blowdown Cooler (116-31001). Incoming city water is heated as it flows through the annulus.

The process sewer flow consists of pump flush and seal water, washdown water, unused potable water, and process drains. This wastewater collects in the Process Sewer and gravity flows to the Process Sewer Sump. The Process Sewer Pump (116-41002-1,2) pumps these wastes to the Equalization System (116-47003). The Process Sewer wastes are combined with sour water from the SCOT Unit (109-47002) in a Static Mixer before entering the Equalization tank w/Mixing System. An Air Blower forces air up through the Tank, accomplishing the following - first, it further mixes the wastewater to ensure that slugs of chemicals that could harm the bio-sludge do not enter the Bio-Plant (116-47005) where phenol is removed; and second, it strips out any dissolved gases, such as H_2S, that may present an odor problem if released to the atmosphere. These vapors combine

3.2.6 Water Treatment (Cont'd.)

with those from the Char Letdown Tank (116-35003) and enter the Ozone Odor Control System (116-47004), where any odor producing constituents are destroyed. The Letdown Tank bottoms consist of the degassed slurry extracted from the Hydroclone (104-45002-1,2). This slurry is combined with ash in the Ash Bunker (103-34001-1,2), from where it is shipped to off-site disposal.

An Effluent Pump pumps the equalized wastewater to the Flotation System (116-47005). Here the wastewater is combined with a coagulant which promotes the formation of larger particles by the joining of incoming particles. These particles consist of suspended and colloidal solids and emulsified oil droplets, and must be removed to prevent contamination of the Bio-Plant sludge. The coagulant is dispersed as the wastewater flows through a Static Mixer and enters the Flocculation Tank, where a flocculant is added so that even larger particles, called flocs, will form. The wastewater then flows into a Flotation Tank, where bubbles generated by an electric current passed through the bottom of the Tank force the flocs to the surface, where they are removed by a Sludge Skimmer. The sludge is then pumped to Sludge Press System (116-47009) while the purified water flows to the Bio-Plant Feed Sump.

Water is lifted from this Sump by the Bio-Plant Feed Pump and combined with recycled effluent from the Sludge Thickening System (116-47008) and the Sludge Press System, and with backwash from the Bed Filter System (116-47007). This combined flow, if necessary, is pH-adjusted and cooled before entering the Bio-Plant Basin.

A biological growth called activated sludge digests the organic content of the wastewater in the Basin, producing additional activated sludge in the process. Aerators supply the oxygen required for digestion.

The Basin discharges to a Clarifier where a flocculant is added. Flocs are formed and they settle as a sludge in the base of the Clarifier. Part of the sludge is recycled to the Basin feed to seed the incoming wastewater with activated sludge, while the balance flows to the Sludge Thickening System. Skimmings are manually removed from the Clarifier on an intermittent basis and are also pumped to the Sludge Thickening System. The Clarifier effluent flows to the Feed Sump of the Bed Filter System for final purification before being discharged from the plant.

3.2.6 Water Treatment (Cont'd.)

The Clarifier effluent is pumped out of the Sump to the top of the Bed Filter. The effluent gravity flows through the Filter and its effluent discharges from its base and is pumped out of the plant. Carryover flocs from the Clarifier trapped in the Filter are intermittently removed by an air backwashing operation. The recovered flocs are recycled to the Bio-Plant Basin.

The net production of bio-sludge from the Clarifier bottoms is concentrated in the Sludge Thickening System. The sludge is blended with a flocculant and fed to a Flotation Tank, where bubbles produced by an electric current passing through the base of the Tank force the flocculated sludge to the surface. The thickened sludge is skimmed off and pumped to the Sludge Digestion System (116-47010). The Flotation Tank effluent is recycled to the Bio-Plant Basin.

The thickened bio-sludge enters the Aerobic Digestor tank where it is mixed and aerated by air supplied by the Digestor Aerator, producing a biologically inert sludge. This sludge is combined with the sludge from the Flotation System in the agitated Feed Tank of the Sludge Press System. A sludge conditioner is added to this tank to prepare the sludge mixture for filtration. This mixture is fed to the Press, where the sludge is filtered, producing a cake suitable for landfill. The Press effluent is recycled to the Bio-Plant Basin.

3.2.7 Utilities and Facilities

References: PFD's 110-001, 115-001, 117-001, 118-001

This section of the report describes required equipment that is not part of the process or the water treatment areas. This equipment is divided into four groups, namely: Instrument/Plant Air, Cooling Water System, Fire Protection System, and Flare. The subjects are described separately below.

Instrument/Plant Air

Air required for instrument operation, for plant cleaning and maintenance, and for other miscellaneous uses, is filtered and then compressed in an Instrument/Plant Air Compressor (110-42001-1, 2). The compressed air is cooled in an Aftercooler prior to entering an Air Dryer (110-47001), in which its dew point is reduced to -40°F. This is done to prevent freezing in the distribution piping or in the plant instrumentation. The dried air enters an Air Receiver (110-35001) which acts as a pressure stabilizer for the air distribution system and as a surge vessel should the Compressor trip off. Air from the Receiver is headered to users on an as-required basis.

Cooling Water System

Cooling water is required for the proper operation of a number of processing steps. The two existing steam turbine condensers are supplied by an existing once through cooling water system using harbor water. An open-loop Cooling Tower (115-44001) provides a continuous supply of cooling water to other users.

Recovered process condensate and boiler blowdowns are quenched by city water and the combined stream provides the bulk of the cooling water make-up. The balance of the make-up consists of city water piped directly to the Cooling Tower.

The cooling tower make-up replaces cooling water losses from the system which occur through:

a. evaporation of part of the recycling cooling water, which cools the remaining water
b. windage and drift of fine liquid water particles out of the Cooling Tower
c. blowdown to prevent the buildup, due to evaporation, and the eventual precipitation of salts in the cooling water piping system.

A C. W. Inhibitor Unit (115-47002) feeds a corrosion inhibitor into the cooling water to control corrosion within the system. The C. W. pH Unit (115-47001) injects acid into the system to prevent salt precipitation which will occur if the pH is not controlled.

3.2.7 Utilities and Facilities (Cont'd.)

Fire Protection

Plant fire protection will be provided by the installation of a fire water loop and hydrants located throughout the plant. The Fire Water Tank (117-34001) contains a two hour supply of fire water at the maximum usage rate. This makes fire water available in the event the city water supply is interrupted. Provisions are included for bypassing this Tank and feeding the city water directly to the loop.

A Jockey Pump (117-41002) operates continuously to ensure that the loop is free of flow obstructions. Two Fire Water Pumps (117-41001-1, 2) are provided. One is motor driven while the second is diesel driven so that pumping could continue in the event a fire would interrupt the power supply. Diesel oil to fuel this Pump is stored in a Diesel Fuel Tank (117-35001). This tank will gravity feed the fuel to the Pump.

Flare

No gases will be flared during normal operations. If an emergency requiring flaring should arise, fuel oil will fuel the pilots of Flare (118-47001) to light off these gases.

Due to the plants' location near a populated area, a ground Flare was selected to satisfy environmental requirements. This flare design hides the flame and minimizes noise generation.

3.3 FUEL SUPPLY AND PREPARATION

3.3.1 Coal Source

Summary

The Westinghouse gasifier is flexible as to the type of coal that can be used as its feed stock and can process the various varieties and ranks of run-of-mine coal available via virtually any domestic source from which United Illuminating would choose to acquire it.

Westinghouse's preferences are minor considerations relative to the economic questions of coal transport; however, as a general rule of thumb, gasifier performance is improved when utilizing coals of high volatility, low grindability number, low ash, low moisture, and, perhaps, a low ash softening temperature. Westinghouse also believes that the effects of spray on freeze retardants and dust suppressants will be negligible provided they are used in the typical fashion and no large doses of high concentration are fed into the gasifier.

It should be noted that after this installation is complete and is operating on whatever coal is finally selected, a change in coal sources may require some minor adjustments to the gasifier and the process operation. These would be of minor cost and minimal down-time and of negligible consideration at this point.

Information was obtained about coal available from seventeen different mines. The FOB mine cost per MM BTU was determined for each coal and the delivered cost per MM BTU was determined for the lower FOB cost coals.

The proximate analyses for these coals were compared to the proximate analysis, ash fusion temperature and grindability of the coals which the Bridgeport Harbor Station was designed to burn. A coal close to the minimum quality needed for Bridgeport Harbor Station was selected as a conservative basis for design of the gasification system.

The coal analysis supplied by United Illuminating as that range that would be suitable for the Bridgeport Harbor Station is tabulated on the following page:

	Typical	Expected Range a/ Minimum	Maximum
Proximate Analysis - %			
Moisture	4.5	2.5	8.0
Ash	9.7	6.0	14.0
Volatile Matter	38.8	25.0	40.0
Fixed Carbon	47.0	45.0	65.0
BTU - As Received	13,000	12,000	14,100
Moisture and Ash Free	15,150	---	---
Ultimate Analysis - %			
Moisture	4.5	2.5	8.0
Carbon	71.2	70.0	80.0
Hydrogen	4.9	4.7	5.5
Nitrogen	1.2	1.1	1.8
Chlorine	---	---	---
Sulfur	3.3	1.5	4.5
Ash	9.7	6.0	14.0
Oxygen (By Diff)	5.2	2.5	5.5
Ash Fusion Temperature - F			
Reducing - Initial Def	2,020	---	---
- Soft (H = W)	2,100	2,000	2,700
- Fluid	2,180	---	---

a/ Not additive

The coal offered by the General Coal Co. out of the Winburne, PA mine has the lowest delivered price per MM BTU ($1.43). The proximate analysis of this coal shows that it is satisfactory both for gasification and for burning in United Illuminating Co. boilers and is recommended for use as the design coal.

3.3.1 Coal Source (Cont'd.)

Typical as-received analysis of this recommended coal is:

Moisture	6%
Ash	10% Maximum
Volatile	24-26%
Fixed Carbon	60-58%
BTU/#	12,300
Sulfur	2.5%
AST	2550°F
Size	2 x 0
Grindability	80
FSI	8

Price FOB Mine $23.25/Ton

Data

A. FOB and Delivered Costs

COMPANY	MINE LOCATION	FOB COST/MM BTU	DELIVERED COST MM/BTU
Consolidated Coal Co.	a) Farmington, W. VA.	$1.147	1.838 (1), 1.760 (2)
	b) Farmington, W. VA.	1.080-1.107	1.827-1.872 (1) 1.743-1.786 (2)
Bethlehem Steel Co.	c) Clarksburg, W. VA.	1.053 (surface)	
	d) Clarksburg, W. VA.	1.2.6 (deep mine)	
Avery Coal Co.	e) Clearfield, PA	0.943	1.596 (2)
	f) Clearfield, PA	0.795	1.639 (2)
C & K Coal Co.	g) Fallentimber, PA	1.320	
	h) Snow Shoe, PA	1.204	
	i) Clarion, Co., PA.	1.326	
	j) Clarion, Co., PA.	1.204	
John K. Irish Coal Co.	k) W. VA. or KY	1.04	
United Energy, Inc.	l) Indiana, PA	1.045	
	m) Butler, PA	0.975	
Pgh. & W. VA. Coal Co.	n)	1.000	1.760
General Coal Co.	o) Royalton, KY	1.050	1.974 (1)
	p) Winburne, PA	0.945	1.423 (1)
	q) Limestone, PA	0.977	1.466 (1)

B. Quoted Coal Analyses - See Attached Table "A"

(1) Transportation by rail and barge.
(2) Transportation by rail only.

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3.3.1 Coal Source (Cont'd.)

Discussion

Coals b, e, f, g, h, and j were eliminated on the basis of high ash content. The other potential screening characterization, ash softening temperature, was not used since the data given was variously incipient and fully liquid temperatures.

Of the remaining candidate coals, coal p offered by General Coal Co. from its Winburne, PA mine has the lowest FOB and delivered cost per MM BTU and is selected for design basis.

Coal m delivered cost was not given by the supplier and was not pursued since the 2% higher ash and geographic disadvantage (Western, PA) would give a higher delivered cost per MM BTU than either coal p or q.

The delivered costs of coals a and b were determined by the Dravo Traffic Department for rail and barge and for rail only delivery. The costs indicate a potential savings for rail only delivery and might reduce the delivered cost of the selected coal further.

Conclusion

Based on November, 1979 quotations, the Winburne, PA coal offered by the General Coal Co. is recommended for use in the design of the combined cycle system at the Steel Point Installation of the United Illuminating Company.

TABLE "A"

Coal	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
Moisture	5-6	5-7					5-7	4-6	4-6	4-6		7	7	6	6	6	6
Ash	7-9	12-15		8	12-14	25-30	11-14	18-24	8-10	14-18	10	12	12	10.5	12	10	12
Volatile	38					20-30	24-27	22-24	35-37	35-37	30	25	30		34	24-26	34-36
Mixed Carbon							53-57					55	55		48	60-58	48-46
M BTU/#	13.5	12.3-12.5	12.8	13	12.5	9.5	12.5	11.5	12.7	11.5-13	12.5	13	12.7	12.5	12	12.3	12
Sulfur	2.7-3	2.7-3.2	2.5	2.5	2.5	3-5	1.5-2	0.7-1.3	2.5-3	2.5-7	<1	1.5		2.5	0.95	2.5	2.4
AST·°F			2600				2100-2600	2800	2100	2100				2009	2700	2550	2550
Size			2x0	2x0	-	3x0	1 1/2x0	2x0	2x0	6x0	2x0*				2x0	2x0	2x0
Grindability	53	53					90-95	75-80	55-60	55-60		70	55		45	80	53
FSI	7 1/2	7 1/2													5-6	8	6
Price FOB/ton	31.00	27.00	27.00	31-32	23.00	12-15	33.00	28.00	34.00	28.00	25.00	27.50	25.00	25.00	25.00	23.25	23.25

*Much Undersize

3.3.2 Coal Transportation

A preliminary survey of coal transportation from the source mine to the plant site was made as described later in this section, but a broader and deeper study should be made in the next phase in the development of the repowering of Steel Point Station.

There are numerous possible sources of a suitable coal that could be used for direct firing of Bridgeport Harbor Station Unit #3 and the coal gasification facility proposed for Steel Point Station. These sources range from Eastern to Mid-West to Western areas for domestic coals. Regardless of the source of the coal, it must be transported by rail and/or water. A study entitled "Coal Transportation Capability of the Existing Rail and Barge Network, 1985 and Beyond" (EPRI EA - 237) was made in 1976 by Manalytics, Inc. for Electric Power Research Institute which addresses some of the problems that could affect the use of coal by utilities. Areas of concern center around the possible mismatch of planned coal production and consumption patterns and quantities with the transportation network presently available for transportation of coal from the mines to the users. The major bottlenecks in the rail transportation system are located on strategic boundries such as mountain ranges and rivers where the capacity of the links in the system cannot be easily increased. The two strategic boundaries of concern in this study are the mountain range running through Pennsylvania and West Virginia and the Hudson River. Of the ten passing links through these mountains, anywhere from two to six could become congested and require a longer transportation route with its inherent increased hauling cost. The five links across the Hudson River are deemed to be adequate to handle the projected increase in coal use on top of the additional increase in all other commodities. Other problems that could affect the rail transportation of coal are the availability of hopper cars and locomotives, properly maintained roadbeds, and rolling stock and financial condition of the railroad companies. Alternate methods of transportation, such as slurry pipelines, may need to be developed to alleviate some of these problems.

Except for inland waterways, the cited report does not discuss water transportation in the Northeast or New England areas. It should be noted that facilities for water transportation of coal in these areas is very limited at the present time and plans for expanding this capability are indefinite.

A more extensive study than the preliminary assessment made for this study should be undertaken to seek a resolution of the possible problems that can be presently foreseen.

3.3.2 Coal Transportation (Cont'd.)

Investigation into providing coal supplied for UI's proposed gasification facility at Steel Point Station in Bridgeport, Conn. indicates that three transportation modes are possible for coal delivery.

a. Direct railroad delivery to Bridgeport Harbor Station.

b. Ocean going tug barge or self-unloading ship from some East Coast port after coal has been delivered there from the mine.

c. Inland type barge from Port Reading, NJ to Bridgeport Harbor Station.

The results of our preliminary survey of these three modes are presented below.

Since the coal must be transported from the mine by railroad in each of the three modes, we will discuss this method first. The coal source area is Winburne, PA, a staging area for coal brought in by dump trucks from the surrounding strip mines for reshipment. Rail service is provided by Con Rail Corporation from Winburne, PA to either Bridgeport, Conn., Port Reading, N.J. or some other eastern seaboard port.

The area of greatest concern when shipping entirely by railroad was the condition of the rail facilities at the mining area and especially the New England area. Our investigations revealed the following information:

A. Direct Railroad Delivery

Coal Source Area

Winburne, PA - Winburne is a staging area for coal brought in by dump trucks from the surrounding strip mines for reshipment.

Rail Yard servicing Winburne - Clearfield, PA.

Rail Cars

70 and 100 Ton cars available. Con Rail's trainmaster stated there is no real problem in supplying cars upon request.

100 Ton cars are loaded at 95 tons
70 Ton cars are loaded at 63 tons.

3.3.2 Coal Transportation (Cont'd.)

This is to avoid overloading as it is extremely expensive to stop and unload cars.

Service

Upon request - no regular service. The trainmaster stated that they usually bring 100 cars to the area at one time, 50 are set aside and 50 are taken to the loading area. If the time permits, the railroad stays with the cars until they are loaded, then they take the loaded cars back to the set-off point and return with the empty cars.

Train loads are set up at 7000 tons: The railroad will hold for 24 hours to collect an additional 7000 tons, but it depends on the availability of other freight as to how and when the trains move out.

Track Conditions

Clearfield yard decent with upgrading of yard set for 1980, but there is talk of an austerity program for this area.

Track to Winburne

26 Miles long in good condition. This track has been upgraded in last two (2) years, but no money has been allowed for other than emergency repair.

Customer Switch to the two (2) loading tracks in fair condition, these two (2) tracks then open into a storage yard of five (5) tracks, where the track is in very poor condition. In this area, the empty rail cars are shoved for storage and then they are pulled back for loading. There is room for expansion of the storage tracks at Winburne.

Loading of Rail Cars

Loading of rail cars is accomplished by a front end loader.

Rail Service out of Winburne

Rail service out of Winburne to Bridgeport, CT, via rail direct is via Clearfield, PA - Jersey Shore, PA and Dewitt, Corning, NY. The railroad crosses the Hudson River in the Albany, NY region. This round about route is necessary because the railroad bridge at Poughkeepsie burned down several years ago and has not been rebuilt. The railroad bridge near Albany is in good condition and can carry unit trains.

3.3.2 Coal Transportation (Cont'd.)

Cars are Weighed

Cars are weighed in motion at McElhatten, near Lockhaven, PA.

Estimated Transit Time

To Bridgeport via Dewitt Yard 5-6 days.

Con Rail, Bridgeport Yard (See Map)

Would service U. I. Bridgeport Harbor Station. Track conditions fair. Capacity of yard, 200 rail cars to run efficiently. The yard is jammed into a populated area of town. A back-up to this yard for holding and storing trains would be an area called "Turkey Brook". Turkey Brook offers two storage tracks that can hold 100 cars each. It is located 10 miles northwest of Bridgeport at Derby Junction, CT. Track conditions good - upgraded in the past two years. All trains moving in from the west through Dewitt Yard would be held here prior to moving into Bridgeport.

Bridgeport Lower Yard (See Map)

In the past, this was the yard immediately adjacent to the U. I. Bridgeport Harbor Station that was used for storage. The yard now has been divided in two - with one half sold to a trucking firm and the other half completely devastated; it would have to be completely rebuilt if this yard is required for car storage. It may be possible to store rail cars at Turkey Brook since not more than 40 cars can be handled at Bridgeport Harbor Station storage yard. The lead tracks servicing this yard and also the U. I. Bridgeport Harbor Station are off the Water Street area and would have to be completely rebuilt. As a matter of record, the last train into this area was fifteen years ago.

Our opinion is that if this coal were to move through Bridgeport yard, Con Rail would have to upgrade Bridgeport yard an. rediscipline the yard personnel.

U. I. Bridgeport Harbor Station, Bridgeport, CT (See Map)

-Location	On the city side of the water.
-Rail Service	Con Rail. Last train into plant fifteen (15) years ago. Track to plant would have to be completely rebuilt.

3.3.2 Coal Transportation (Cont'd.)

-Track Inside	Not used in fifteen (15) years. Badly in need of repair.
Plant to Storage Yard	
- Storage Yard	Five (5) tracks - each 1/5 mile long, holding ten (10) cars. Rail - Good Ties - Fair, Base - Good.

Estimated Rate

Con Rail Corporation has provided an estimated rate of \$14/N.T. for moving the coal from Winburne, PA to U. I.'s Bridgeport Harbor Station.

B. Railroad and Ocean-Going Barge

Dravo's discussions with several shipping companies indicate that ocean barge delivery may be a problem. Locations such as Baltimore, Philadelphia, Newport News, and Norfolk, VA engage in ocean shipment of coal. Another port, Port Reading, NJ has been doing some shipping, was shut down for a time and was reactivated in March, 1980, due to the increased interest in coal shipment.

Discussion with one of two major transport companies, headquartered in New York, reveals that there is a lack of available American Flagships to perform this duty. A new self-discharging ship costs \$20-30 MM and they would only contemplate building such a vessel under a secured long-term contract from a utility. The cost of such ships and current fuel costs would determine the freight rate. They mentioned that they are currently designing a new coal handling and unloading ship and are bidding for business with a New England power company to haul coal to Brayton Point (near Providence, RI).

They indicated that non-self-unloading barges could be utilized that could be unloaded with a clamshell type unloader and mentioned that only 17 boat carrier ships were in operation and probably only 5 seaworthy tug type barge ships. These barges would need a monor modification to be used with U. I.'s existing barge unloader.

This company indicated that a FIOT rate of about \$4.50/N.T. from Port Reading, NJ was their estimate of what it should cost to ship coal to New England.

The coal would be hauled from Winburne, PA to the chosen port via Harrisburg, PA by Con Rail Corporation.

3.3.2 Coal Transportation (Cont'd.)

Estimated Transit Time

To Port Reading, NJ via Harrisburg, PA	3 Days
Transfer to barge from rail cars	1 Day
To Bridgeport Harbor Station from Port Reading	1-1/2 Days
Total Transit Time	5-1/2 Days

Estimated Rate

Railroad to Port Reading, NJ	$10.00/N.T.
Transfer charge	1.00/N.T.
Barge to Bridgeport Harbor Station	4.50/N.T.
Total	$15.50/N.T.

C. Railroad and Inland Type Barge via Port Reading

Rail service to Port Reading, NJ is via Rutherford Yard at Harrisburg, PA on Con Rail Corporation tracks.

Port Reading Ownership

The yard, track, dock, and car dumper are actually owned by the Public Service Electric and Gas Co. of Newark, NJ. This entire operation has been leased to and is operated by the Con Rail Corporation. The lease is for 55 years with 49 years remaining.

The coal dumper presently operates 7.5 hours per day (five day week) handling coal for Public Service Electric and Gas only. The Con Rail people state that the dumper could run on a 24 hour schedule, seven days a week, allowing for proper maintenance.

The dumper was not in use between October, 1979 and March, 1980, as the Public Service Power House that is serviced by Port Reading was temporarily shut down during this interval.

Rail Staging Area

Tracks are in fair condition capable of holding 500 cars. If the yard would by upgraded, it would have a storage capacity of 1800 cars.

Thaw Shed

Old but usable; capacity for heating 36 cars at one time.

3.3.2 Coal Transportation (Cont'd.)

Track to Coal Dumper

In excellent condition and very well maintained.

Coal Dumper

Originally built in 1917 - burnt to the ground in 1951 and rebuilt in 1951, well maintained with a capacity for dumping twenty (20) 100-ton rail cars per hour.

Operation

The cars are moved from the Yard to the dumper track by engine, they are then pulled to the dumper via cable, locked in and turned over to release the coal into barges. They are then returned back to the original position, thence via cable down the opposite side past the switch, thence via gravity move back to the yard area.

Dock Facility

Is in good condition, present depth is 17 to 18 feet; when it is dredged it has a depth of 26 feet. The area will hold at least four (4) barges with pulley motors to move barges around.

Water Service

Presently there is only one (1) carrier in the Port Reading area that offers barge and tow service, Express Marine.

Express Marine

Has in the Port Reading area four (4) 2600 ton double skin barges measuring 18' x 38' x 142' and two (2) 3000 ton single skin barges measuring 19' x 40' x 160'. They are reported to be in good condition and as they were in service, Dravo did not see these barges.

A cursory inspection of two (2) of Express Marine's barges that were in dry dock for refurbishing found them to be in fine condition.

Express Marine has additional barges in other areas that would be made available to U. I.

3.3.2 Coal Transportation (Cont'd.)

Distance

Via the Water route from Port Reading, NJ to Bridgeport, CT, is 74 miles.

Transit Time

To Port Reading via Harrisburg, PA	3 Days
To Bridgeport Harbor Station from Port Reading, Estimated in good weather	37 Hr. rd. trip
Transfer from rail to barge	1 Day
Total one way	5-1/2 Days

Scheduled Service

None.

Estimated Rate

Winburne, PA to Port Reading, NJ	$10.00/N.T.
Transfer charge	1.00/N.T.
Port Reading to Bridgeport Harbor Station	3.60/N.T.
Total estimated rate	$14.60/N.T.

Consideration of the above alternates and the problems that could be encountered in rehabilitating the rail facilities at Bridgeport Harbor Station coupled with the contemplated conversion of the BHS Unit #3 to coal firing, led to a decision to use alternate "C" as the most appropriate routing for this study.

3.3.3 Coal Receipt, Storage, and Preparation

Introduction

Coal is delivered to the site by barge. The coal can be unloaded at either the Bridgeport Harbor Station or the Steel Point Station. Ground area availability limits storage at Steel Point to about 15 days supply. Therefore, to provide 90 days of on-site storage, a 75 day supply will be stored at Bridgeport Harbor Station, with coal transfer to Steel Point on an as-required basis.

Description (PFD's 101-001, 101-002, 102-001)

Barges unloading at the Bridgeport Harbor Station are positioned by a Barge Haul (101-48001). A Barge Unloader (101-48002) unloads the 2" x 0 coal onto Conveyor #13 (101-43001) at a rate of 1600 tons per hour (TPH). The coal is fed to Stacker #16 (101-43002) which stacks the coal by discharging through a Telescoping Chute (101-48004) to form the 75 day storage pile. A Front End Loader (101-49001) reclaims the coal by feeding the below-grade Hopper (101-34001). This Hopper is unloaded by Conveyor #31A (101-43003) which feeds the Loading Conveyor (101-43004). The coal is transferred onto a Boom Conveyor (101-43005) and loaded into Transfer Barges (101-35001-1, 4). These barges are then towed to the Steel Point Station. The reclaiming operation is carried out at a rate of 550 TPH.

A Barge Haul (101-48005) positions the transfer or delivery barges for unloading at the Steel Point Station. A Clam Shell Unloader (101-48006) unloads the coal and dumps it onto the storage pile at a rate of 500 TPH. A Front End Loader (101-49002) reclaims the coal by feeding the below-grade Hopper (101-34002). This Hopper is unloaded by a Feeder (101-43006) which feeds the Feed Conveyor (101-43007). The coal is then transferred onto the Feed Elevator (101-43008), which loads a Raw Coal Source Bin (102-35001) at a rate of 128 TPH.

Each unloading and handling station is equipped with a Sump Pump (101-41001, 101-41002) for transferring coal pile runoff to Waste Treatment (Area 16), where it is neutralized. Each station also has a Dust Supressant System (101-48003, 101-48007) for spraying a dilute dust supressant solution at all conveyor transfer points.

The Raw Coal Source Bin feeds the Coal Drying and Sizing System (102-47001). The coal, which is normally not dried, is fed to the Crusher. A Recycle Blower provides a gas stream which entrains the crushed coal and carries it overhead into the Cyclone. Oversize coal is recycled to the Crusher when it is desentrained in the Classifier Section. A Booster Blower produces the pressure necessary to force the recycling gas through the Filter. The recycle gas loop is completed with the Filter discharge feeding the Recycle Blower suction.

3.3.3 Coal Receipt, Storage and Preparation (Cont'd.)

The 1/4" x 0 crushed coal is removed by rotary valves from the Cyclone and the Filter and transferred to the Sized Coal Storage Bins (102-34001-1, 4) by the Sized Coal Conveying System (102-43003). This transfer occurs at a rate of 128 TPH.

Each Sized Coal Storage Bin is equipped with a Storage Bin Live Bottom (102-43001-1, 4) to facilitate unloading. Sized Coal Feeders (102-45001-1, 4) transfer the coal to a Feed Coal Conveyor System (102-43004), which discharges into the Feed Coal Surge Bins (103-35001-1, 4) in the gasification area. This transfer is carried out at a rate of 75 TPH.

Should the coal have a total moisture content greater than 6% when received, drying would be required and would be done simultaneously with crushing. The Dryer Furnace can use either #2 fuel oil or clean fuel gas produced in the process as fuel. The FD Fan blows air into the Dryer Furnace, and the hot combustion gases are piped to the Crusher. A quantity of gas equivalent to that of the combustion gases is withdrawn from the system at the discharge of the Recycle Blower.

3.4 ELECTRIC FEATURES

3.4.1 General

The power generated at this installation would be sent to a 115 KV switchyard and then distributed to the system. The general arrangement of the electrical system is shown on the Main One Line Diagram, Figure 3.5-1.

3.4.2 Generator

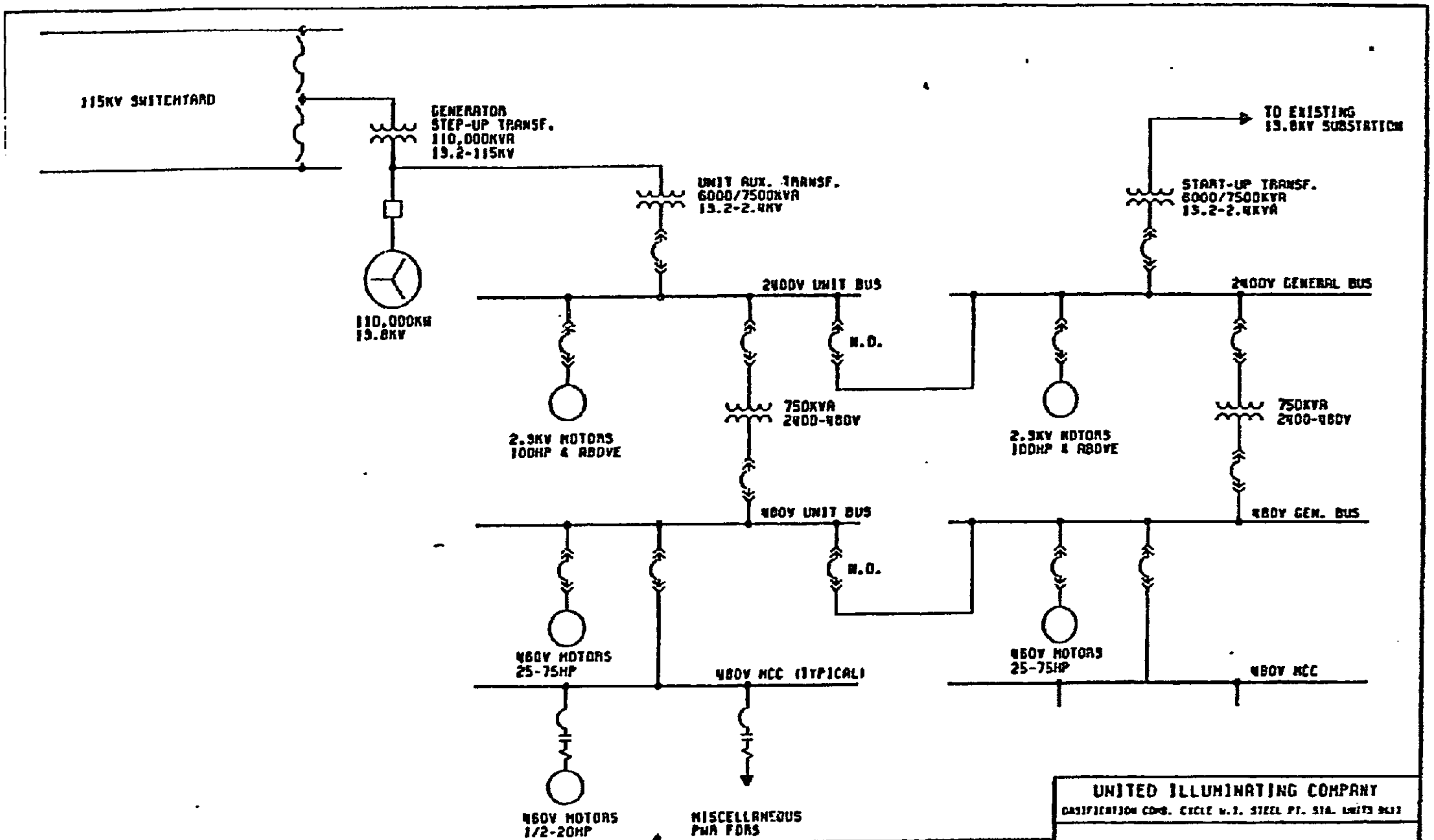
The generator will be rated 110,000 KVA, 3600 rpm, 60 hertz, 85 % power factor, 13.8 KV with a short circuit ratio of 0.58. The generator, main transformer, and the unit-auxiliary power transformer will be interconnected by isolated-phase bus duct. The interconnection will be solid, except for flexible connectors at each termination point.

3.4.3 Transformers

The main step-up, unit auxiliary and startup transformers will be the oil-filled, outdoor type.

3.4.4 Auxiliary Power System

The 13.2 - 2.4 KV unit auxiliary transformer will be connected to the 2400 volt unit bus. This bus will supply power to 2300 volt motors 100 hp and larger as well as a 480 volt secondary unit substation. The startup transformer will be connected to the 2400 volt general bus supplying power to 2300 volt motors for common services as well as a 480 volt secondary unit substation feeding common auxiliaries at 480 volts. Bus-tie circuit breakers which will be normally open will be provided at the 2400 volt and 480 volt levels. Automatic transfer will be provided at each voltage level so that upon loss of the unit supply, all electrical auxiliaries will be supplied from the startup transformer. Motors 25 to 75 hp will receive power from the 480 volt unit and general buses; motors 1/2 to 20 hp and small miscellaneous loads will be supplied from centrally located 480 volt motor control centers. The electrical system will include the indoor and outdoor lighting, public address and telephone communication system, alarms, grounding system and all conduit cable and cable trays necessary to complete the electrical auxiliary system.



UNITED ILLUMINATING COMPANY

GASIFICATION COMB. CYCLE U.I. STEEL PT. STA. UNITS 9&10

MAIN ONE LINE DIAGRAM

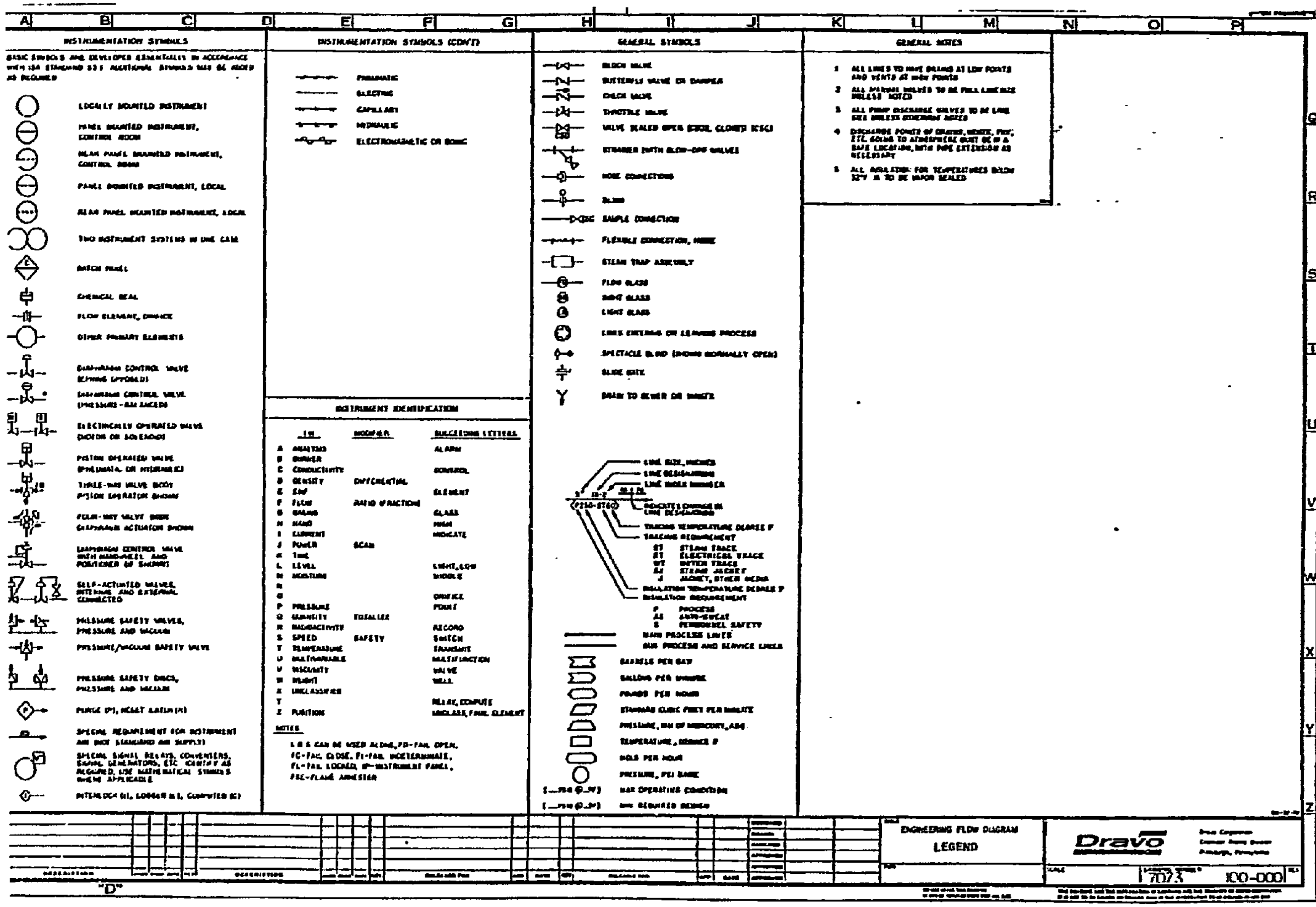
Gibbs & Hill, Inc.

SCALE: -/-

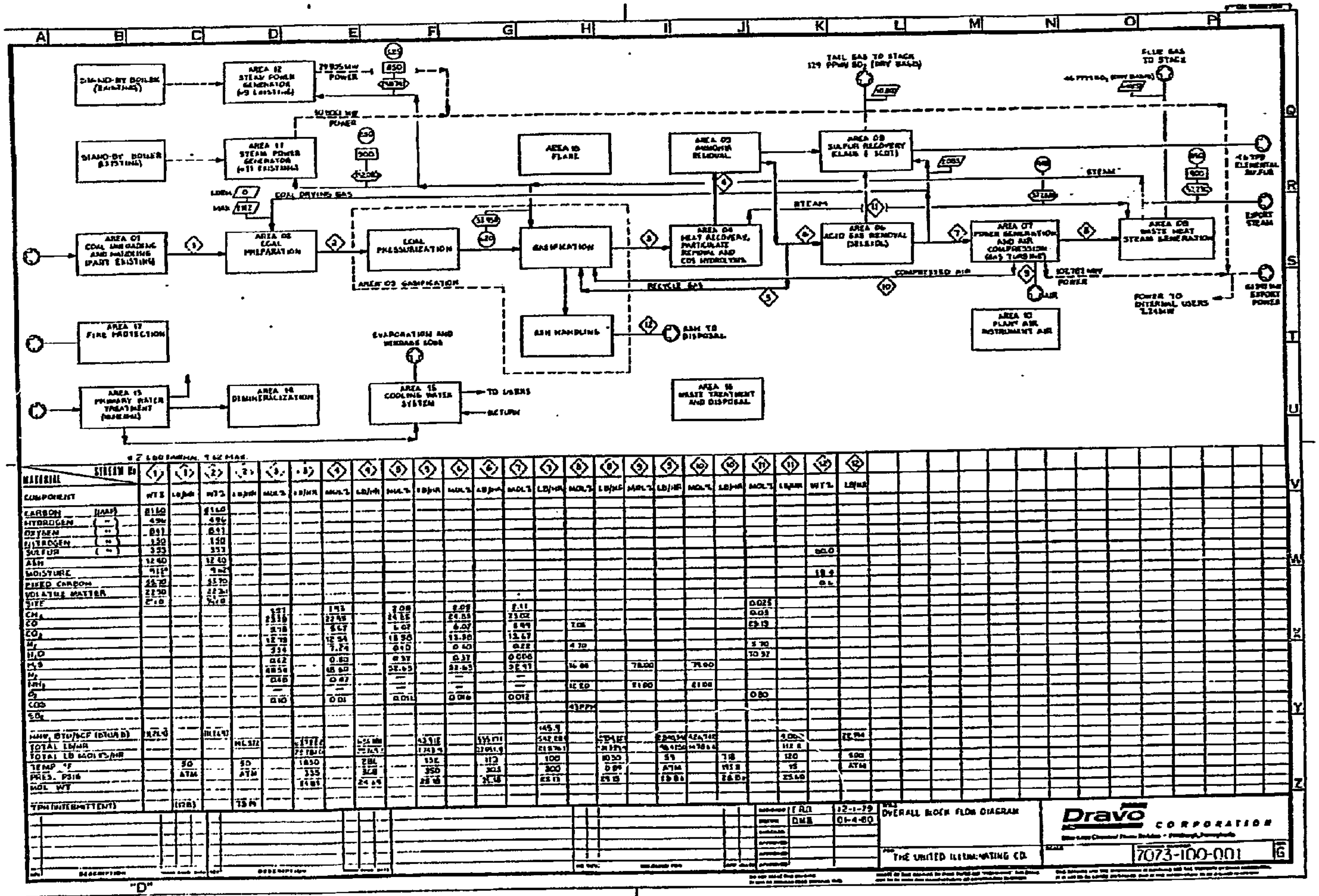
JOB NO. 11-2891-001

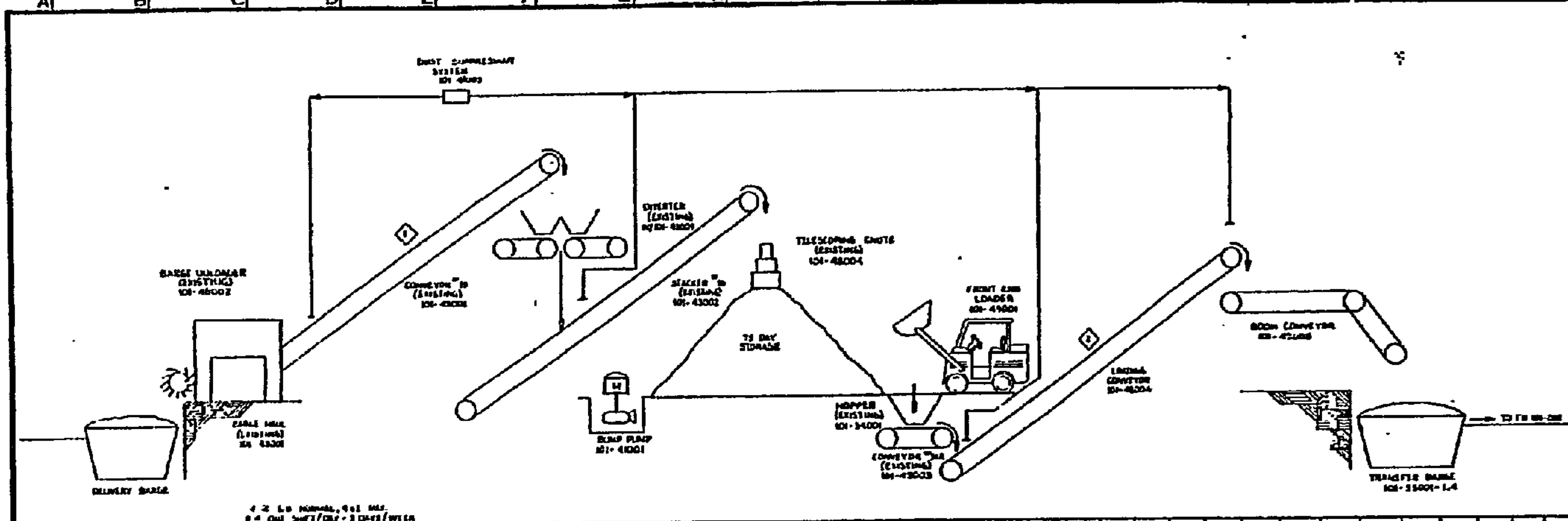
FIG. 3.5-1

	1												U I REPOWERING STUDY
	1												U.I. REPOWERING STUDY
MICRO FILM	ISSUE NO.	DATE	DWN.	CHKD.	ARCH	STR.	MECH	ELEC		I&C	SHLD	CONST	P.M.
					APPROVALS								ISSUED FOR



INSTRUMENTATION SYMBOLS
LOCALLY MOUNTED INSTRUMENT
PANEL MOUNTED INSTRUMENT, LOCAL
TWO INSTRUMENT SYSTEMS IN ONE CASE
CHEMICAL SEAL
OTHER PRIMARY ELEMENTS
INSTRUMENTATION SYMBOLS (CONT)
PNEUMATIC
ELECTRIC
CAPILLARY
HYDRAULIC
ELECTROMAGNETIC OR SONIC
INSTRUMENT IDENTIFICATION
A ANALYSIS
ALARM
CONTROL
GENERAL SYMBOLS
BLOCK VALVE
BUTTERFLY VALVE OR DAMPER
CHECK VALVE
THROTTLE VALVE
STRAINER WITH BLOW-OFF VALVES
HOSE CONNECTIONS
SAMPLE CONNECTION
FLEXIBLE CONNECTION, HOSE
STEAM TRAP ASSEMBLY
FLOW GLASS
SIGHT GLASS
LIGHT GLASS
LINES ENTERING OR LEAVING PROCESS
SPECTACLE BLIND (SHOWN NORMALLY OPEN)
SLIDE GATE
DRAIN TO SEWER OR WASTE
LINE SIZE, INCHES
GENERAL NOTES
1 ALL LINES TO HAVE DRAINS AT LOW POINTS AND VENTS AT HIGH POINTS
2 ALL MANUAL VALVES TO BE FULL LINE SIZE UNLESS NOTED
4 DISCHARGE POINTS OF DRAINS, VENTS, ETC. GOING TO ATMOSPHERE MUST BE IN A SAFE LOCATION, WITH PIPE EXTENSION AS NECESSARY
ENGINEERING FLOW DIAGRAM
LEGEND
Dravo
7073
100-000
"D"


STAND-BY BOILER (EXISTING)
AREA 12 STEAM POWER GENERATOR
AREA 11 STEAM POWER GENERATOR
AREA 01 COAL UNLOADING AND HANDLING (PART EXISTING)
AREA 02 COAL PREPARATION
COAL PRESSURIZATION
GASIFICATION
ASH HANDLING
AREA 03 GASIFICATION
AREA 10 FLARE
AREA 05 AMMONIA REMOVAL
AREA 04 HEAT RECOVERY, PARTICULATE REMOVAL AND COS HYDROLYSIS
AREA 08 SULFUR RECOVERY (CLAUS & SCOT)
AREA 06 ACID GAS REMOVAL (SELEXOL)
AREA 07 POWER GENERATION AND AIR COMPRESSION (GAS TURBINE)
AREA 09 WASTE HEAT STEAM GENERATION
AREA 13 PLANT AIR INSTRUMENT AIR
AREA 17 FIRE PROTECTION
AREA 13 PRIMARY WATER TREATMENT
AREA 14 DEMINERALIZATION
AREA 15 COOLING WATER SYSTEM
AREA 16 WASTE TREATMENT AND DISPOSAL
TAIL GAS TO STACK
FLUE GAS TO STACK
COAL DRYING GAS
STEAM
RECYCLE GAS
COMPRESSED AIR
ASH TO DISPOSAL
EVAPORATION AND WINDAGE LOSS
TO USERS
RETURN
POWER TO INTERNAL USERS
EXPORT STEAM
EXPORT POWER
ELEMENTAL SULFUR
AIR
POWER
STREAM No.
MATERIAL
COMPONENT
CARBON
HYDROGEN
OXYGEN
NITROGEN
SULFUR
ASH
MOISTURE
FIXED CARBON
VOLATILE MATTER
TOTAL LB/HR
TEMP °F
PRES. PSIG
MOL. WT
OVERALL BLOCK FLOW DIAGRAM
THE UNITED ILLUMINATING CO.
Dravo CORPORATION
7073-100-001
"D"



MATERIAL / STREAM No	1	2
COMPONENT	WT %	WT %
CARBON (MAF)	81.68	81.60
HYDROGEN (MAF)	4.96	4.96
OXYGEN (MAF)	8.41	8.41
NITROGEN (MAF)	1.50	1.50
SULFUR (MAF)	3.53	3.53
FIXED CARBON	55.3	55.7
VOLATILE MATERIAL	22.3	22.3
ASH	12.4	12.4
MOISTURE	9.6	9.6
SIZE	2"x0	2"x0
TEMP °F	50	50
TPH (INTERMITTENT)	[illegible]	1550

PROCESS FLOW DIAGRAM

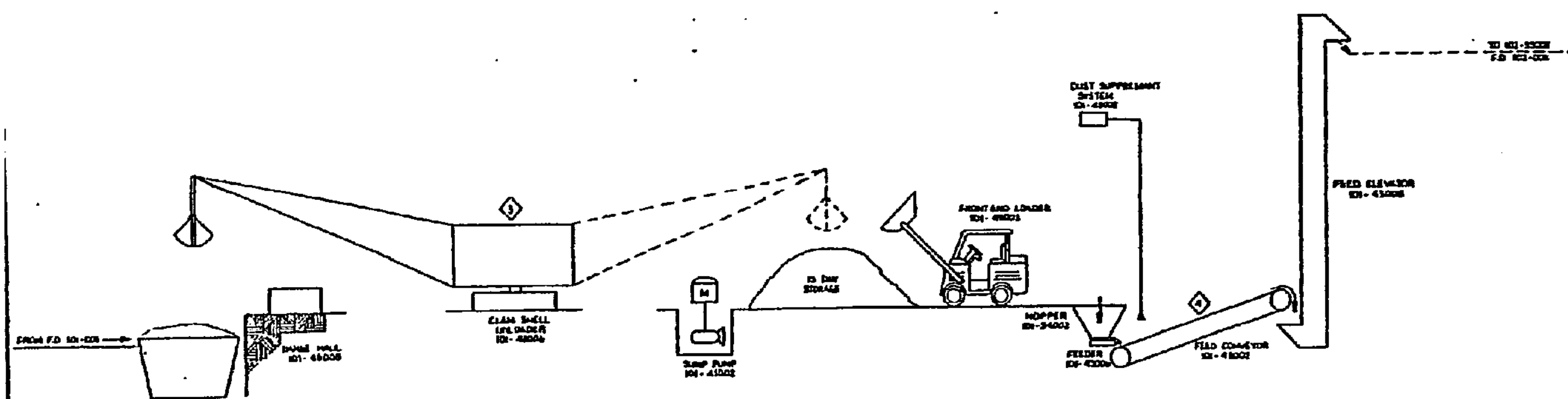
COAL UNLOADING AND HANDLING
BRIDGEPORT HARBOR STATION

Dravo CORPORATION

7073 101-001 C

2-11-86
3-17-80

"D"



* 2 6 NORMAL, 4 12 MAX
* 6 8 DAL SHIFT/DAY - 5 DAYS/WEEK
* * 6 9 THREE SHIFTS/DAY - 5 DAYS/WEEK

MATERIAL / STREAM No.	3	4
COMPONENT	WT %	WT %
CARBON (MAF)	81.60	81.60
HYDROGEN (MAF)	4.96	4.96
OXYGEN (MAF)	8.41	8.41
NITROGEN (MAF)	1.30	1.30
SULFUR (MAF)	3.55	3.55
FIXED CARBON	55.7	55.7
VOLATILE MATERIAL	22.5	22.5
ASH	12.4	12.4
MOISTURE	9.6*	9.6*
SIZE	2"x0	2"x0
TEMP °F	80	80
TPH (INTERMITTENT)	1500*	200**

DRAWN	E R D 2-13-80
CHECKED	D.J. PATRICK 3-15-80

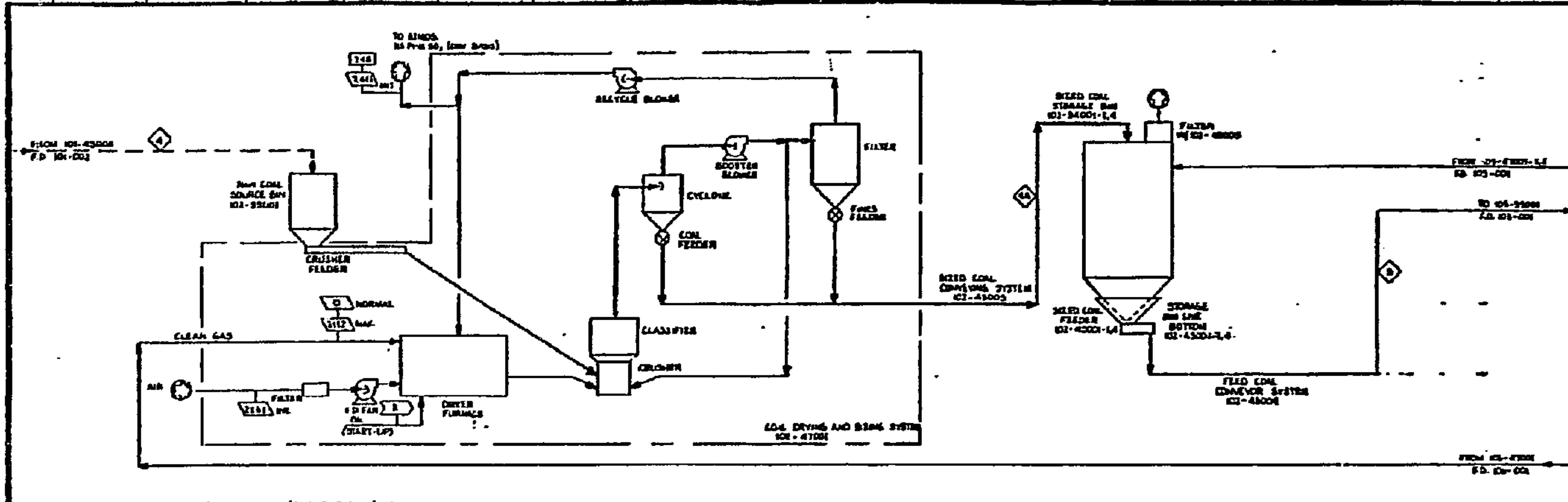
PROCESS FLOW DIAGRAM

COAL UNLOADING AND HANDLING
STEEL POINT STATION

Dravo CORPORATION

7073 101-002 A

"D"



\# THREE SHIFTS/DAY, FIVE DAYS/WEEK

MATERIAL / STREAM No.	2	4A	5
COMPONENT	WT %	WT %	WT %
CARBON (MAF)	81.6	81.6	81.6
HYDROGEN (MAF)	4.94	4.94	4.90
OXYGEN (MAF)	8.41	8.41	8.41
NITROGEN (MAF)	1.50	1.50	1.50
SULFUR (MAF)	3.55	3.55	3.55
FIXED CARBON	55.7	55.1	55.1
VOLATILE MATERIAL	32.3	32.3	32.3
ASH	12.46	12.40	12.40
MOISTURE	9.63	9.63	9.63
SIZE	2"x0	3/4"x0	3/4"x0
TPH (INTERMITTENT)	(334)*	(138)*	73.60
CONTINUOUS LBS/HR			146,312
TEMP. °F	50	50	50

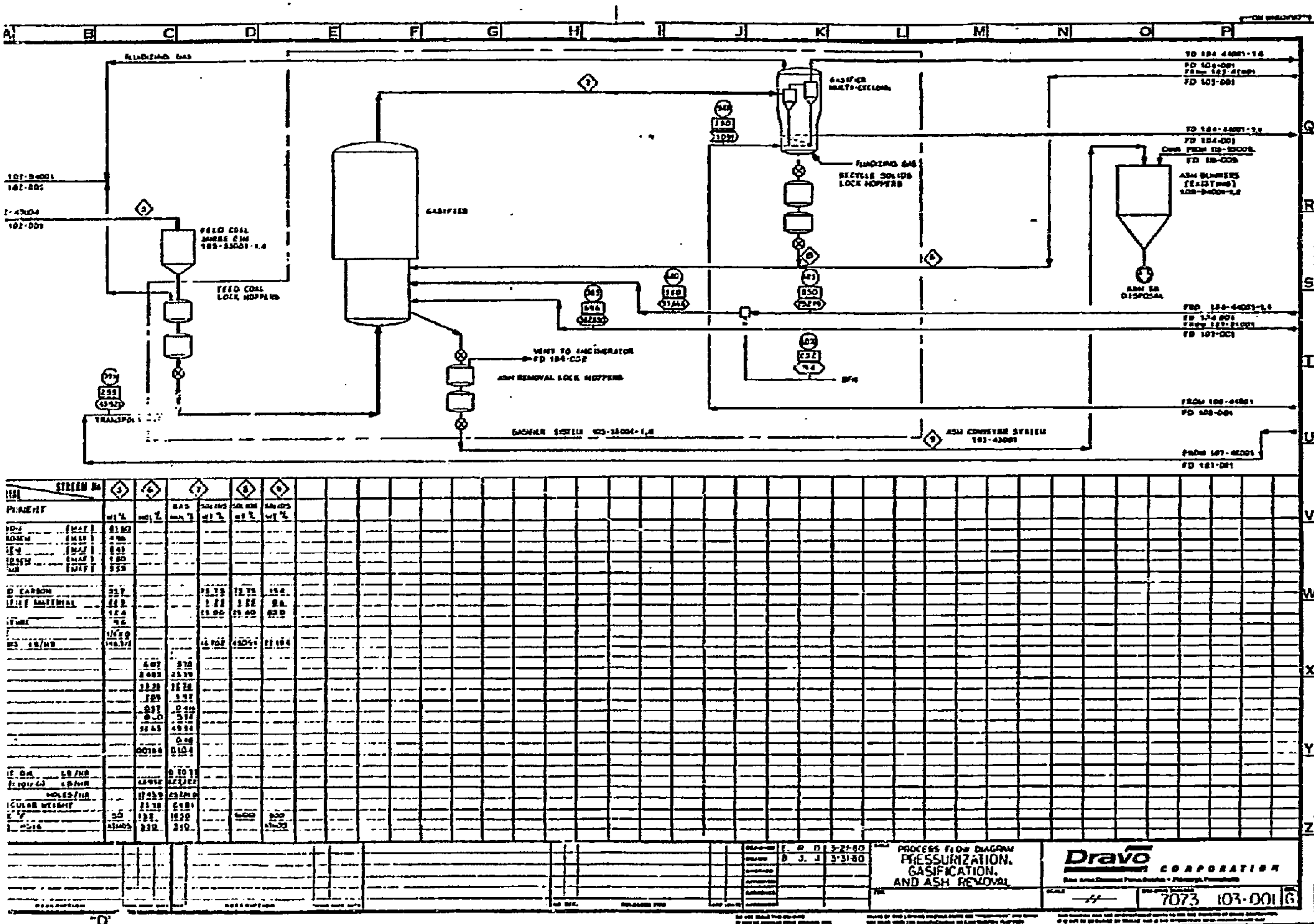
"D"

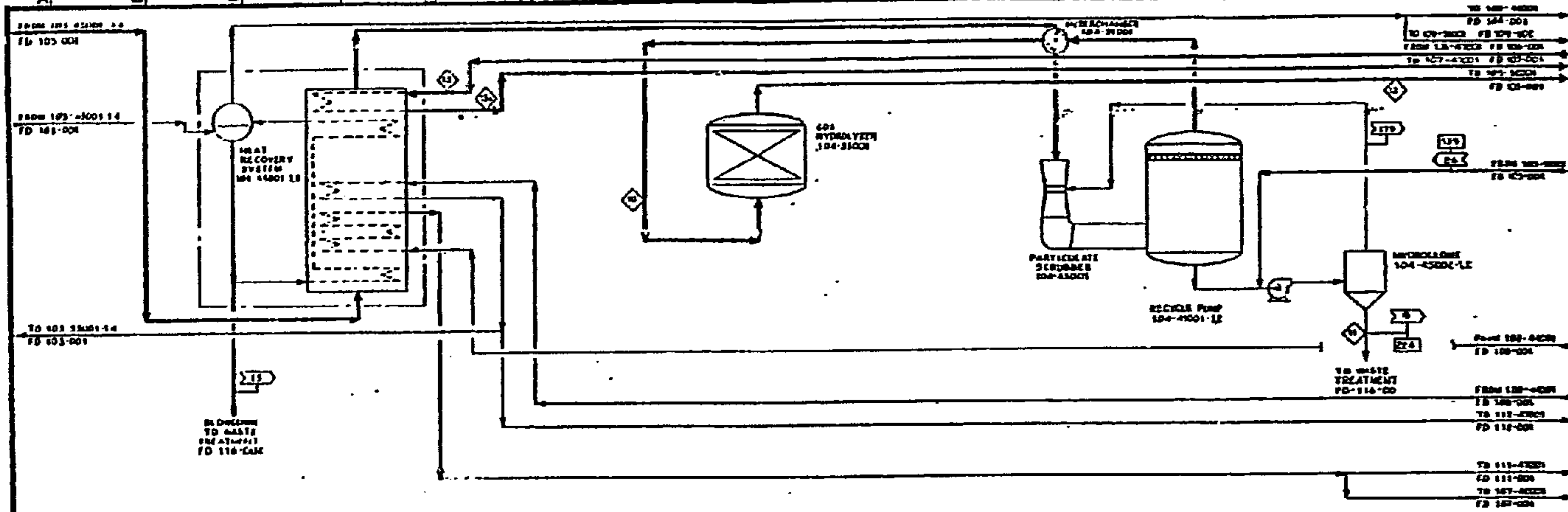
PROCESS FLOW DIAGRAM

COAL PREPARATION

Dravo CORPORATION

7073 102-001 E


FLUIDIZING GAS
FEED COAL LOCK HOPPERS
GASIFIER
GASIFIER MULTI-CYCLONE
FLUIDIZING GAS
RECYCLE SOLIDS LOCK HOPPERS
ASH BUNKERS (EXISTING)
ASH TO DISPOSAL
VENT TO INCINERATOR
ASH REMOVAL LOCK HOPPERS
ASH CONVEYER SYSTEM
BFW
STREAM No.
PROCESS FLOW DIAGRAM
PRESSURIZATION,
GASIFICATION,
AND ASH REMOVAL
Dravo
CORPORATION
7073 103-001 G
"D"



STREAM No. / MATERIAL	[illegible]		[illegible]	[illegible]	[illegible]	[illegible]
COMPONENT	GAS MOL %	SOLIDS WT %	WT %	MOL %	MOL %	MOL %
CARBON (MAF)	—	—	—	—	—	—
HYDROGEN (MAF)	—	—	—	—	—	—
OXYGEN (MAF)	—	—	—	—	—	—
NITROGEN (MAF)	—	—	—	—	—	—
SULFUR (MAF)	—	—	—	—	—	—
FIXED CARBON	—	[illegible]	[illegible]	—	—	—
VOLATILE MATERIAL		[illegible]	[illegible]			
ASH	—	[illegible]	[illegible]	—	—	—
MOISTURE						
SIZE	—	—	—	—	—	—
SOLIDS LB/HR		[illegible]	[illegible]	—	—	—
CO_2	[illegible]	—	TR	[illegible]	[illegible]	[illegible]
CO	[illegible]			[illegible]	[illegible]	[illegible]
H_2	[illegible]	—	—	[illegible]	[illegible]	[illegible]
CH_4	[illegible]	—	—	[illegible]	[illegible]	[illegible]
H_2S	[illegible]	—	TR	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	—	—	[illegible]	[illegible]	[illegible]
N_2	[illegible]			[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	—	[illegible]	[illegible]		
COS	[illegible]	—	—	[illegible]	[illegible]	[illegible]
LIGHT OIL LB/HR	—		[illegible]	—		
GAS (& SOLIDS) LB/HR	[illegible]		[illegible]	[illegible]	[illegible]	[illegible]
GAS MOLS/HR	[illegible]	—	—	[illegible]	[illegible]	[illegible]
MOLECULAR WEIGHT	[illegible]			[illegible]	[illegible]	[illegible]
TEMP °F	[illegible]	—	[illegible]	[illegible]	[illegible]	[illegible]
PRES PSIG	[illegible]			[illegible]	300	300

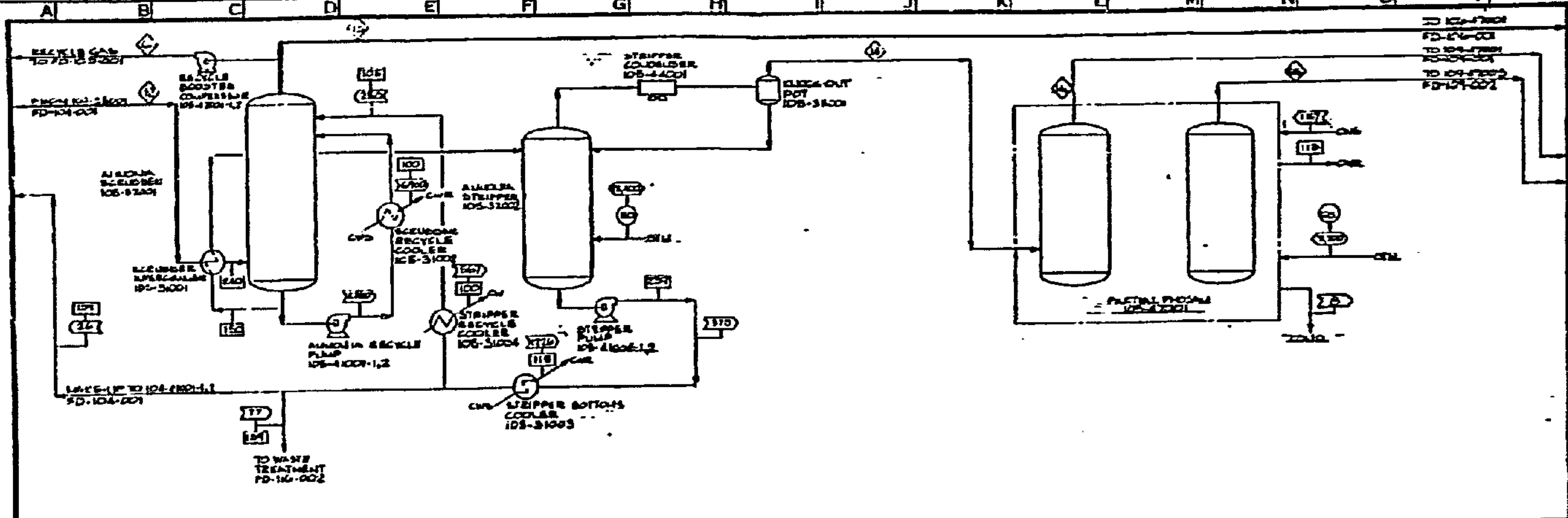
PROCESS FLOW DIAGRAM
HEAT RECOVERY,
COS HYDROLYSIS AND
PARTICULATE REMOVAL

E. R. D 1-21-80
B. J. J 4-9-80

Dravo CORPORATION

7073-104-001 G

"D"



MATERIAL / STREAM No.	6	12	13	14	16	19
	MOL %	MOL %	VOL %	MOL %	MOL %	MOL %
CO_2	2.07	2.76	2.07	16.83	44.37	
CO	24.66	22.18	24.66			
H_2	15.66	17.64	15.65			
CH_4	[illegible]	[illegible]	[illegible]			
H_2S	0.37	[illegible]	0.37	16.53	44.51	
H_2O	[illegible]	7.14	0.40	[illegible]	10.60	[illegible]
N_2	52.63	[illegible]	52.62			
NH_3		0.41		[illegible]	[illegible]	70.60
COS	[illegible]	[illegible]	[illegible]			
GAS	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
GAS MOL/HR	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
MOLECULAR WT	25.23	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
TEMP. °F	[illegible]	264	110	150	160	[illegible]
PRES. PSIG	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

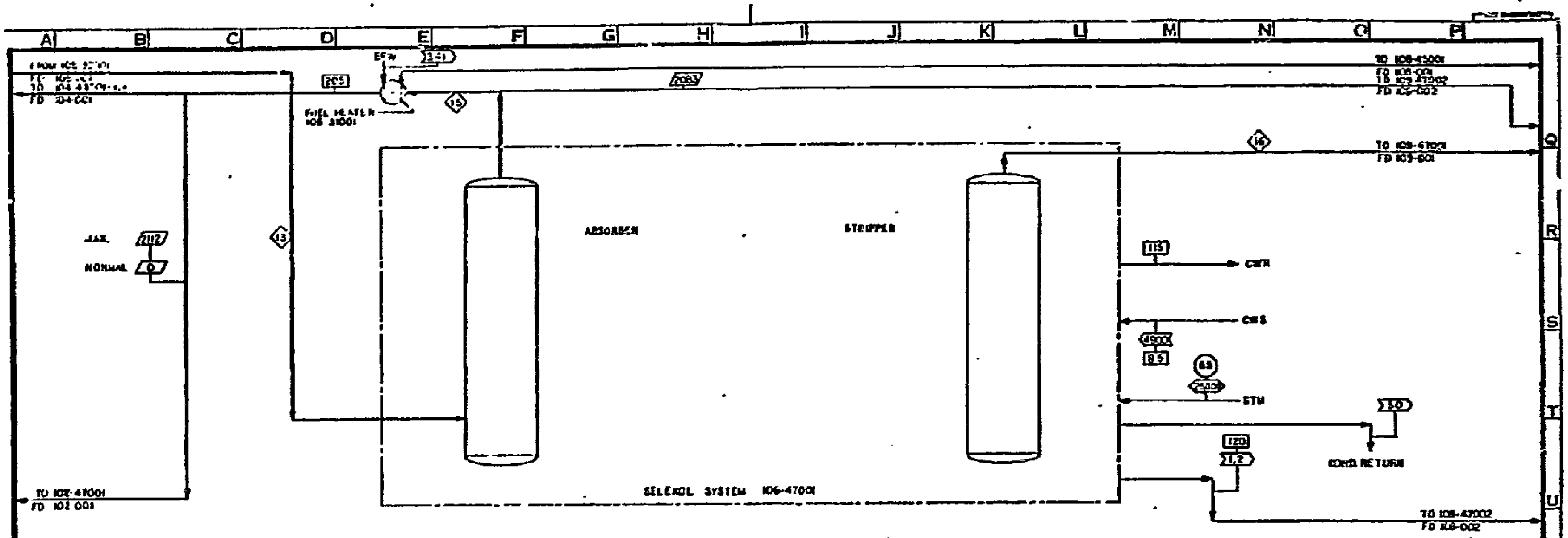
PROCESS FLOW DIAGRAM

AMMONIA REMOVAL

Dravo CORPORATION

7173 105-001 C

"D"



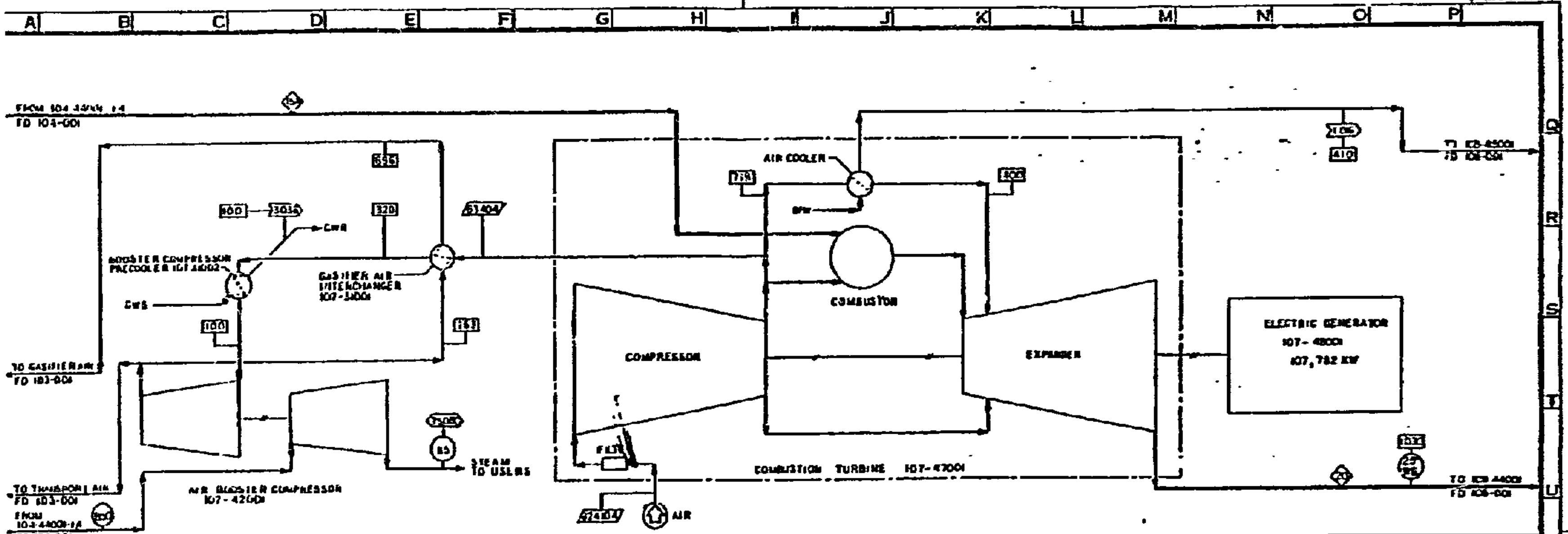
MATERIAL / STREAM No.	13	15	16
COMPONENTS	MOL %	MOL %	MOL %
CO_2	6.07	5.93	71.13
CO	24.81	25.02	0.01
H_2	13.38	13.61	
CH_4	3.83	3.11	1541 PPM
H_2S	0.37	10 PPM	20.12
H_2O	0.10	0.22	5.16
N_2	52.61	52.91	
NH_3			
COS	60 PPM	23 PPM	0.80
GAS SCF/HR	[illegible]	[illegible]	[illegible]
GAS MOL/HR	[illegible]	[illegible]	[illegible]
MOLECULAR WT	25.10	25.13	35.60
TEMP °F	110	100	120
PRESSURE PSIG	305	300	15

"D"

PROCESS FLOW DIAGRAM
ACID GAS REMOVAL
(SELEXOL)

Dravo CORPORATION

7073-106-001 C



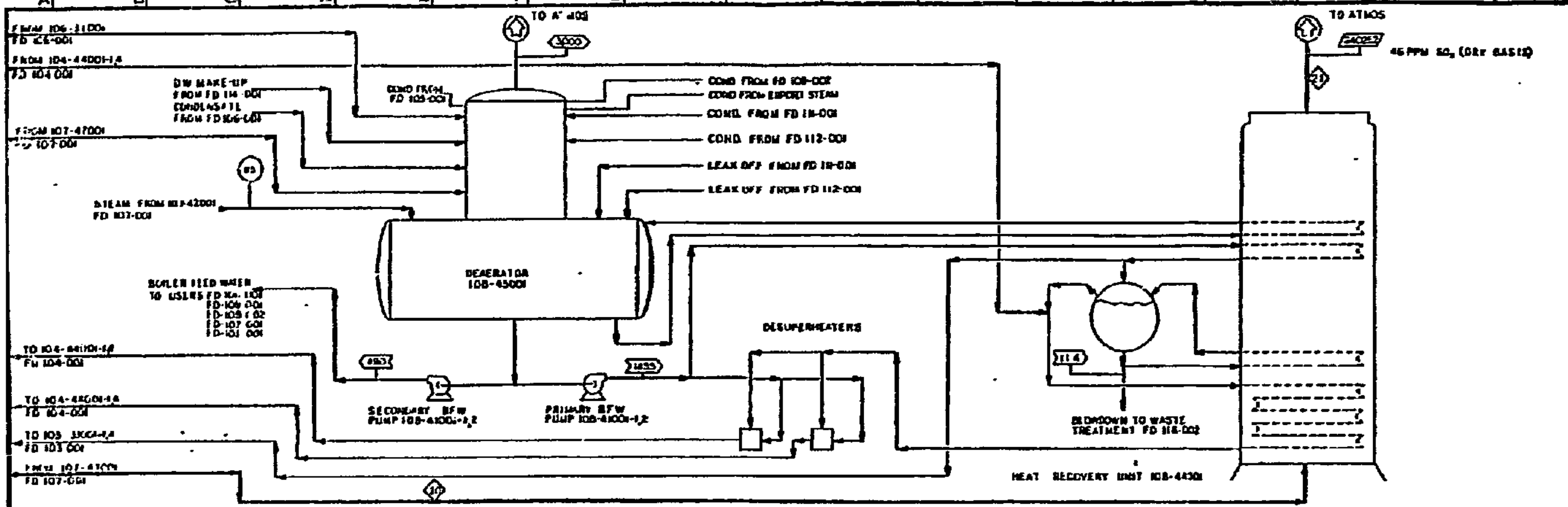
STREAM No. / MATERIAL		
COMPONENT	VOL %	VOL %
CO_2	[illegible]	[illegible]
CO	[illegible]	
H_2	[illegible]	
CH_4	[illegible]	
NH_3	[illegible]	
H_2O	[illegible]	[illegible]
N_2	[illegible]	[illegible]
COS	[illegible]	
O_2		[illegible]
SO_2		[illegible]
GAS LB/HR	[illegible]	[illegible]
GAS MOLS/HR	[illegible]	[illegible]
MOLECULAR WT	[illegible]	[illegible]
TEMP °F	500	1050
PRESSURE PSIG	300	15 WG

PROCESS FLOW DIAGRAM
GAS TURBINE POWER GENERATION

Dravo CORPORATION

7073 - 107 - 001 C

"D"



MATERIAL / STREAM No	20	21
COMPONENT	MOL %	MOL %
CO_2	7.85	7.85
H_2O	4.70	4.70
N_2	76.93	75.66
O_2	[illegible]	12.22
SO_2	[illegible] PPM	135 PPM
GAS LB/HR	[illegible]	[illegible]
CFS MOL/HR	[illegible]	[illegible]
MOLECULAR WT	[illegible]	[illegible]
TEMP °F	[illegible]	[illegible]
PRESSURE PSIG	[illegible]	[illegible]

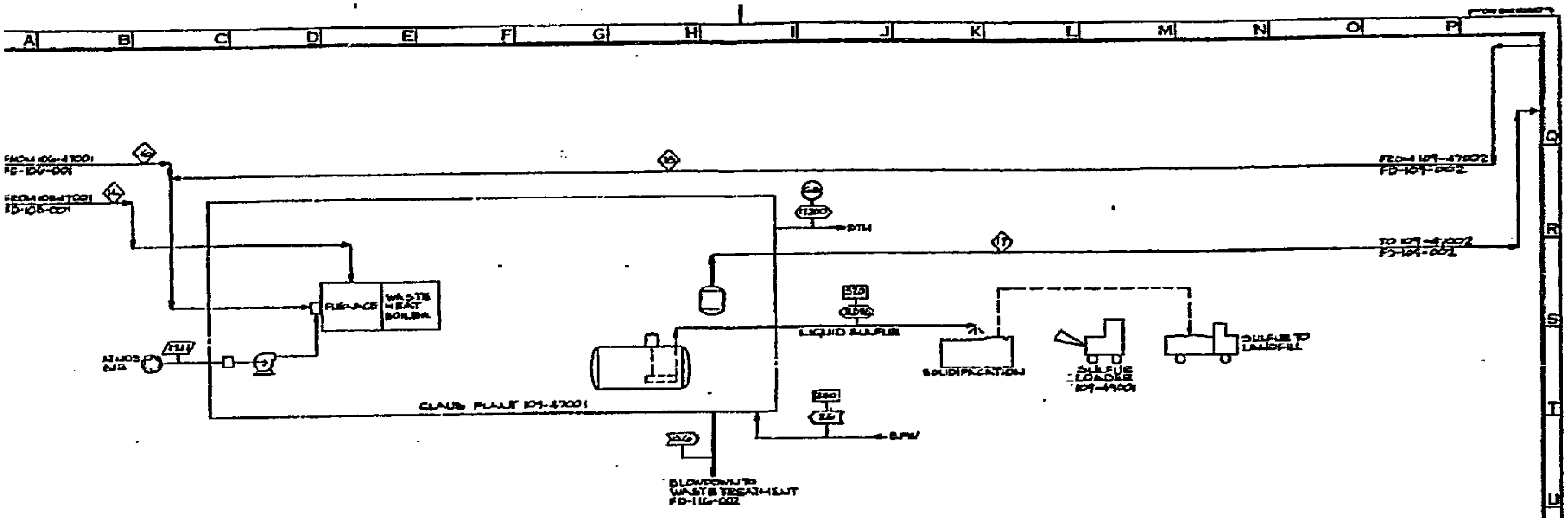
"D"

PROCESS FLOW DIAGRAM
WASTE HEAT STEAM
GENERATION

E.R.D. 2-1-80
MINSHULL 4-7-80

Dravo CORPORATION

7073 - 108 - 001 C



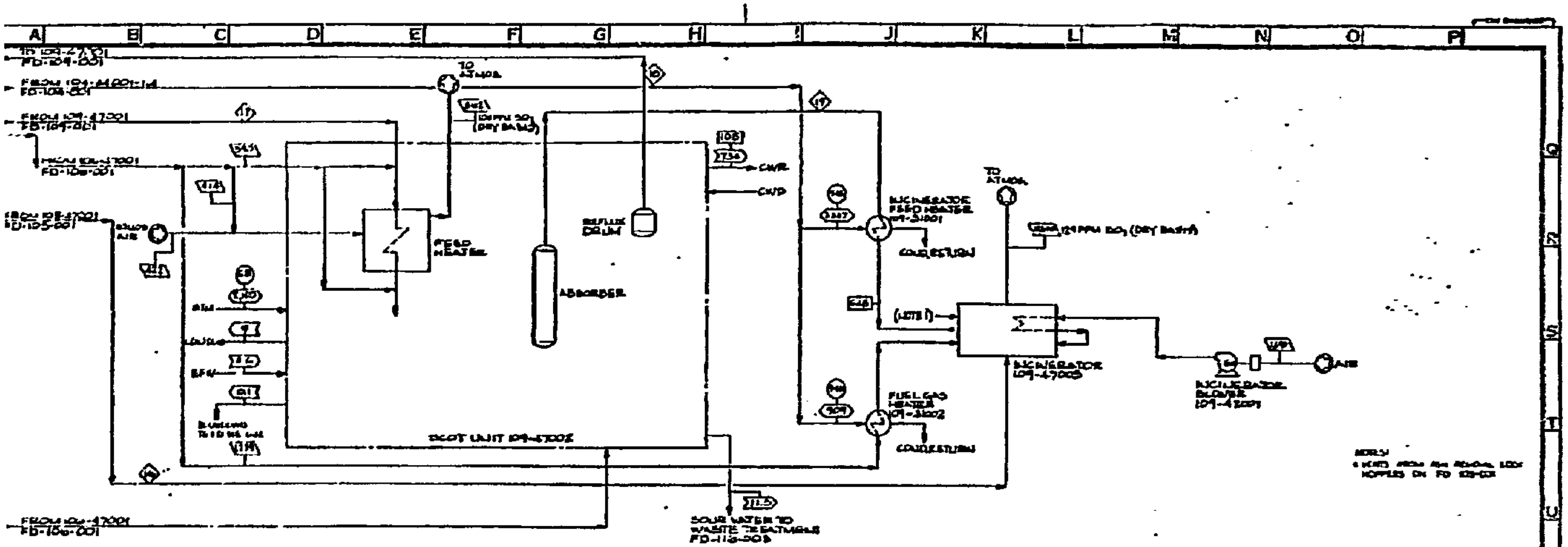
STREAM No. / MATERIAL	14	16	17	18
COMPONENT	MOL %	MOL %	MOL %	MOL %
CO_2	44.59	78.15	0.23	5.86
CO	—	0.63	—	
CH_4	—	[illegible]		3.96
H_2S	44.43	70.82	0.46	11.43
COS		0.87		
H_2O	10.42	6.72	38.35	7.60
N_2		—	58.83	—
NH_3	0.27	—		—
SO_2	—	—	0.13	—
GAS LB/HR	4527	4000	28045	1.186
GAS MOL/HR	92.6	112.4	1106	35.20
MOLECULAR WT	[illegible]	35.60	25.19	36.24
TEMP °F	150	120	350	110
PRES PSIG	65	16	4	7

"D"

PROCESS FLOW DIAGRAM
SULFUR RECOVERY (CLAUS)

Dravo CORPORATION

109-001 D



MATERIAL / STREAM No.	16	17	18	19
COMPONENT	MOL %	MOL %	MOL %	MOL %
CO_2		6.25	[illegible]	10.04
CO				
H_2				1.40
CH_4			2.90	
H_2S		0.66	11.44	0.07
[illegible]	21.20	31.26		3.62
[illegible]		56.83	7.80	63.11
[illegible]	78.60			
SO_2		2.15		
LB/HR	8649	29293	1152	74310
MOLS/HR	123.6	1108	[illegible]	2544
MOLECULAR WT	17.21	26.19	55.64	28.75
TEMP. °F	194	720	120	100
PRESS. PSIG	6.5	2	5	ATMOS.

"D"

ERICKSON 4-3-80

PROCESS FLOW DIAGRAM

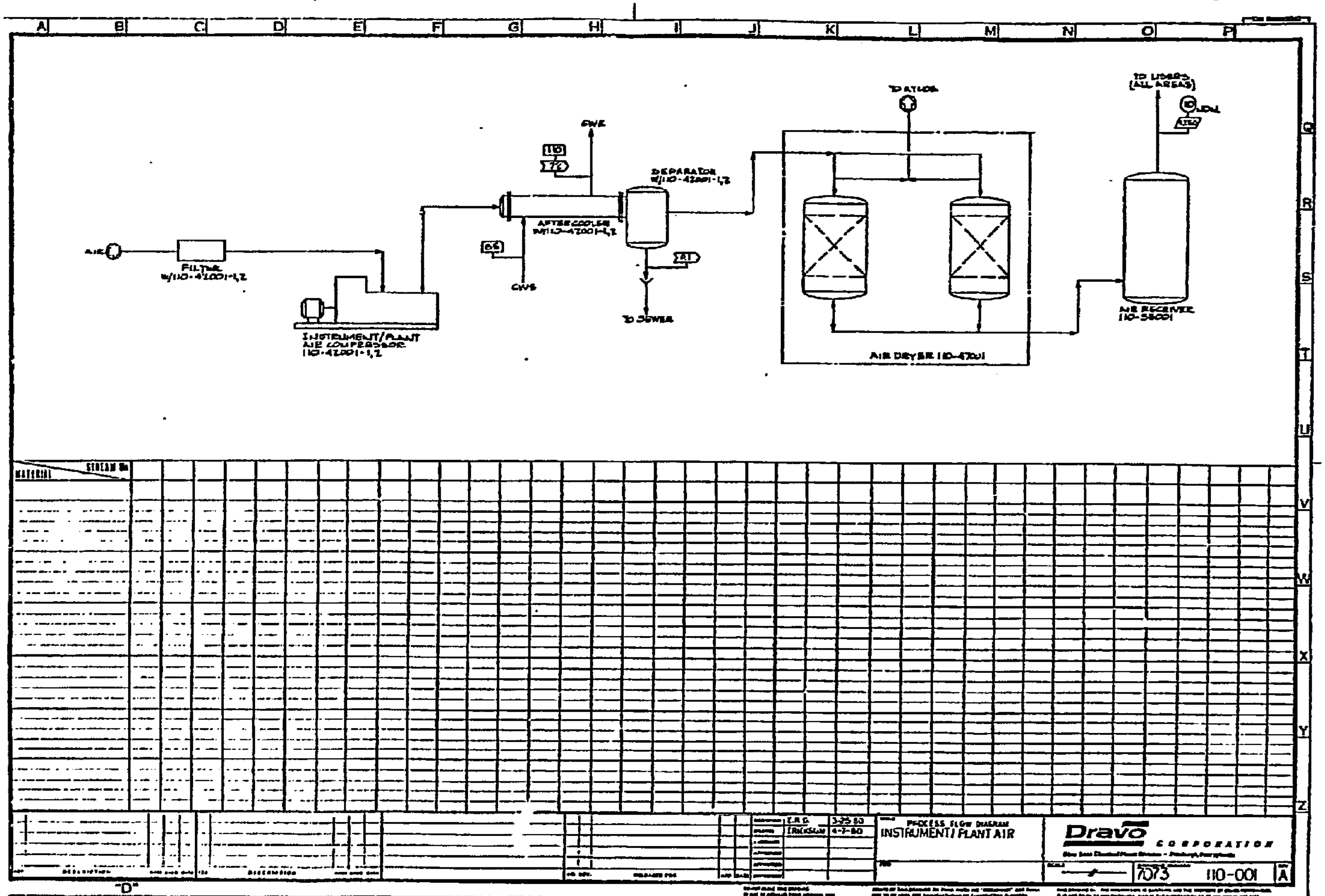
SULFUR RECOVERY (SCOT)

Dravo CORPORATION

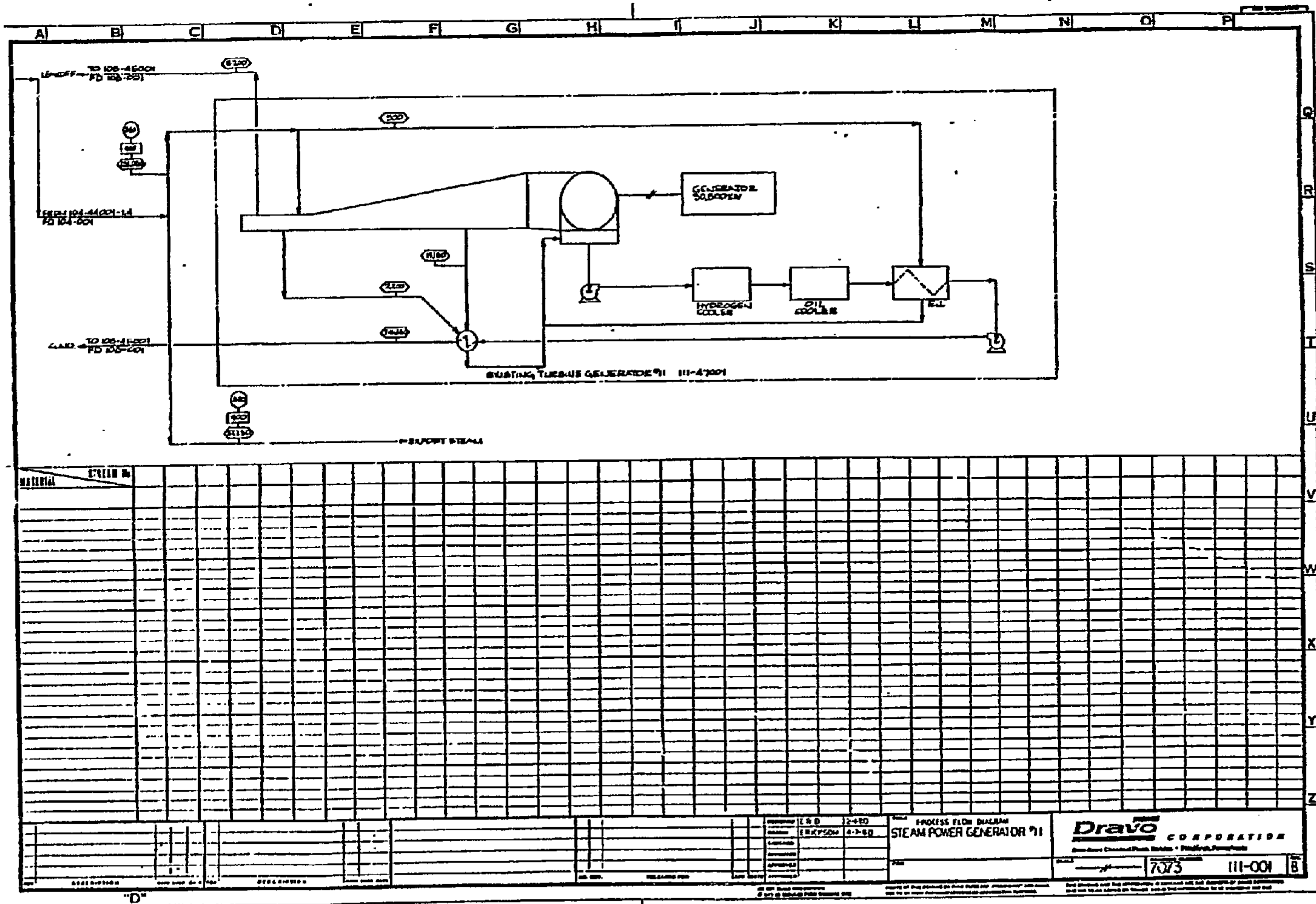
7073

109-202

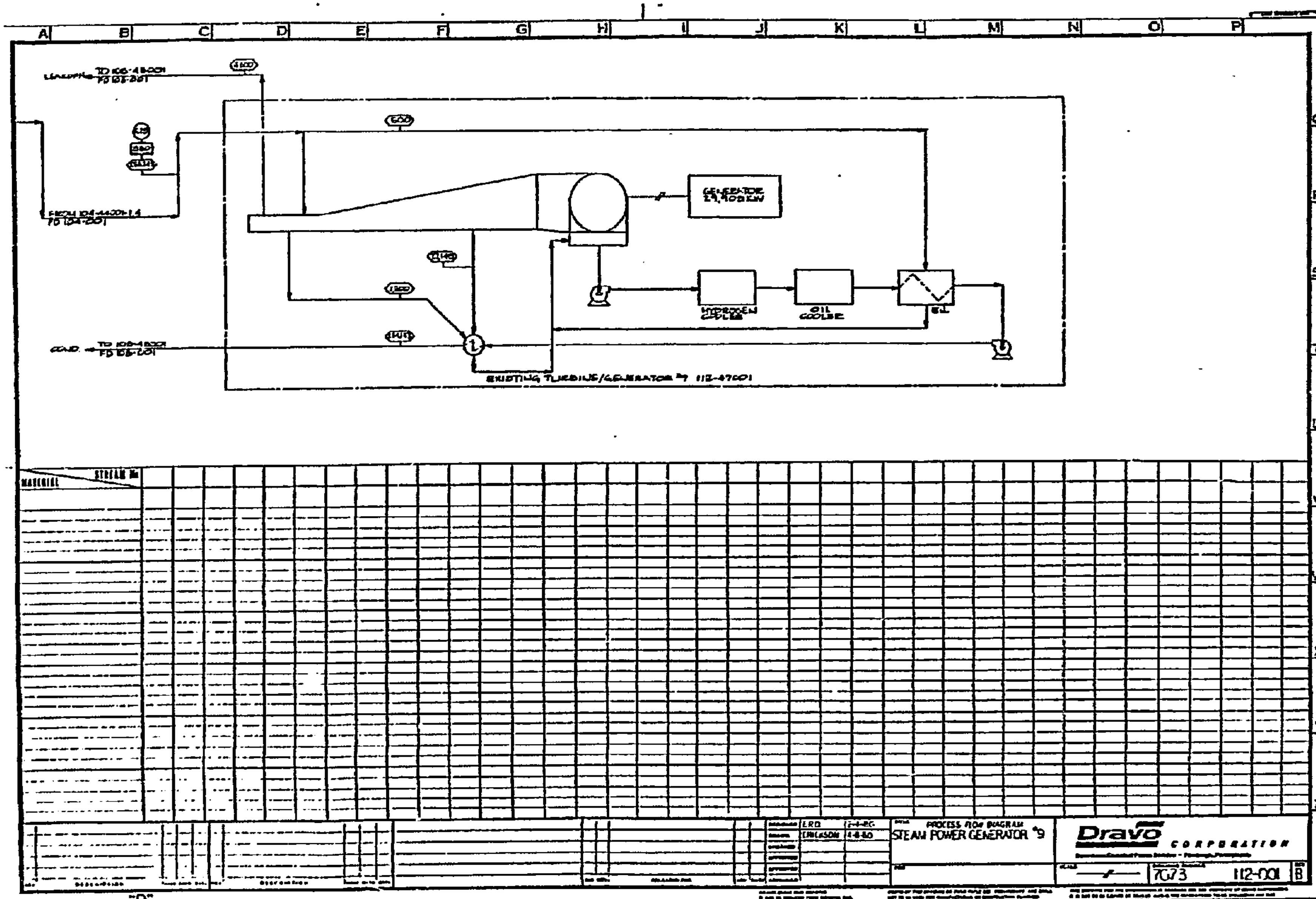
D



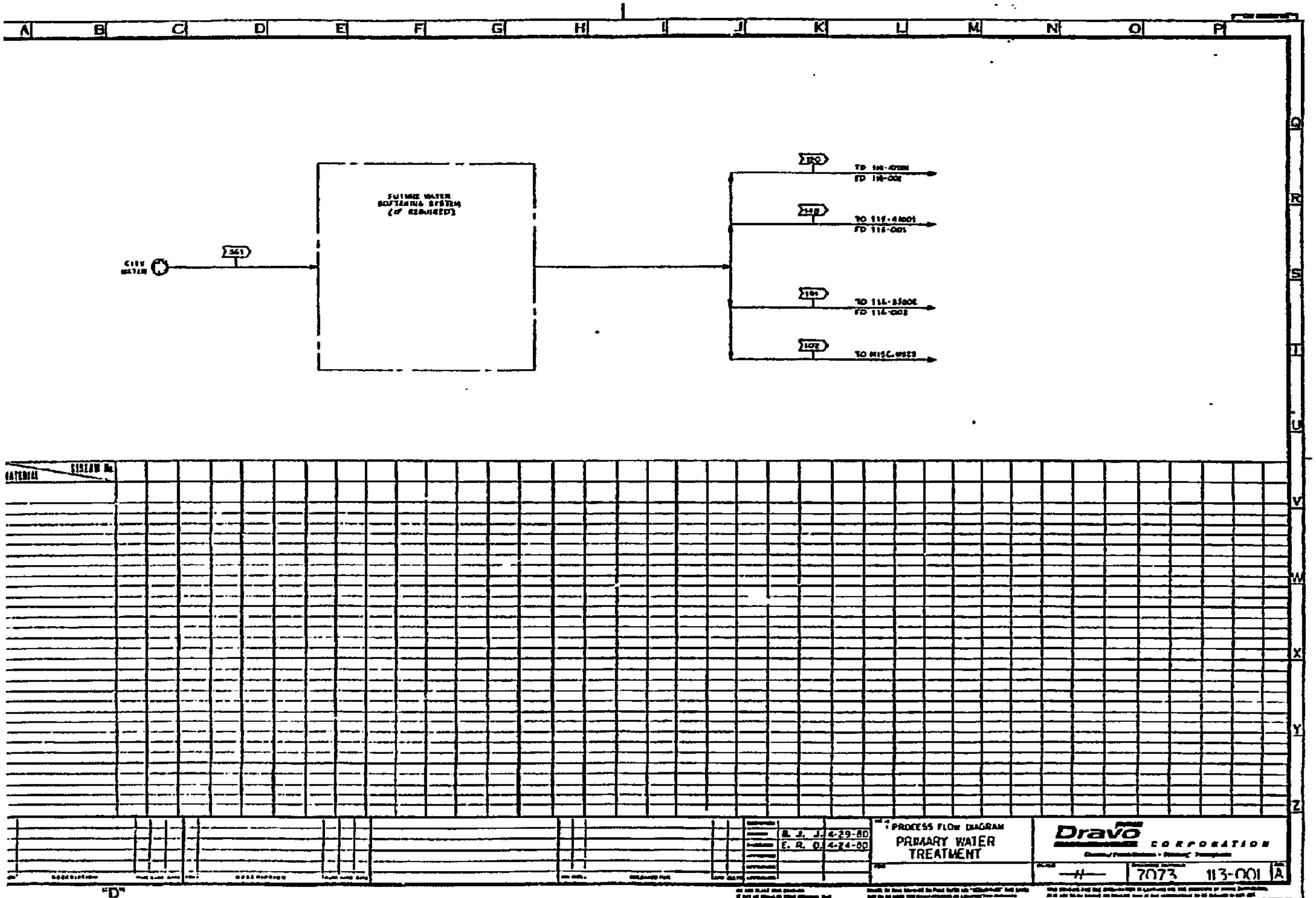
AIR
FILTER W/110-42001-1,2
INSTRUMENT/PLANT AIR COMPRESSOR 110-42001-1,2
AFTERCOOLER W/110-42001-1,2
SEPARATOR W/110-42001-1,2
CWR
CWS
TO SEWER
TO ATMOS.
AIR DRYER 110-47001
TO USERS (ALL AREAS)
AIR RECEIVER 110-58001
MATERIAL
STREAM No.
"D"
PROCESS FLOW DIAGRAM
INSTRUMENT/PLANT AIR
E.R.G. 3-25-80
ERICKSON 4-7-80
Dravo CORPORATION
7073
110-001
A

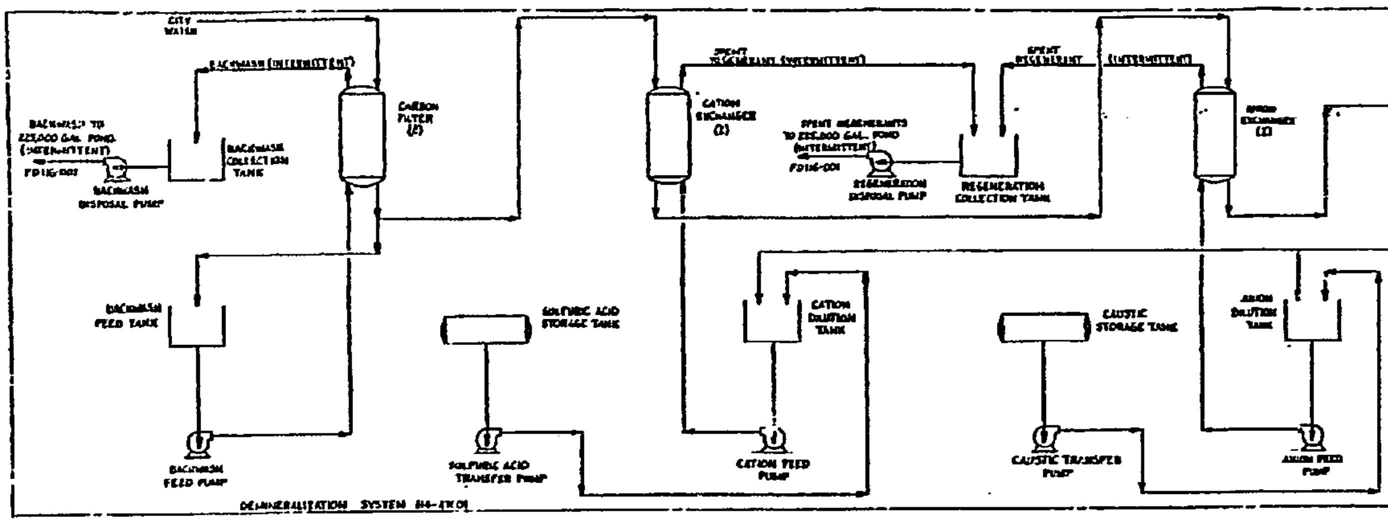


GENERATOR SUBPOWER
HYDROGEN COOLER
OIL COOLER
EXISTING TURBINE GENERATOR #1 111-47001
SUPPORT STEAM
MATERIAL
STREAM No.
PROCESS FLOW DIAGRAM
STEAM POWER GENERATOR #1
Dravo CORPORATION
7073
111-001
B
"D"



EXISTING TURBINE/GENERATOR #9 112-47001
HYDROGEN COOLER
OIL COOLER
MATERIAL
STREAM No
"D"
PROCESS FLOW DIAGRAM
STEAM POWER GENERATOR #9
E.R.D.
ERICKSON
Dravo CORPORATION
7073
112-001
B


CITY WATER
FUTURE WATER SOFTENING SYSTEM (IF REQUIRED)
PROCESS FLOW DIAGRAM
PRIMARY WATER TREATMENT
B. J. J. 4-29-80
E. R. D. 4-24-80
Dravo CORPORATION
7073
113-001
A
"D"



MATERIAL / STREAM No.																																						

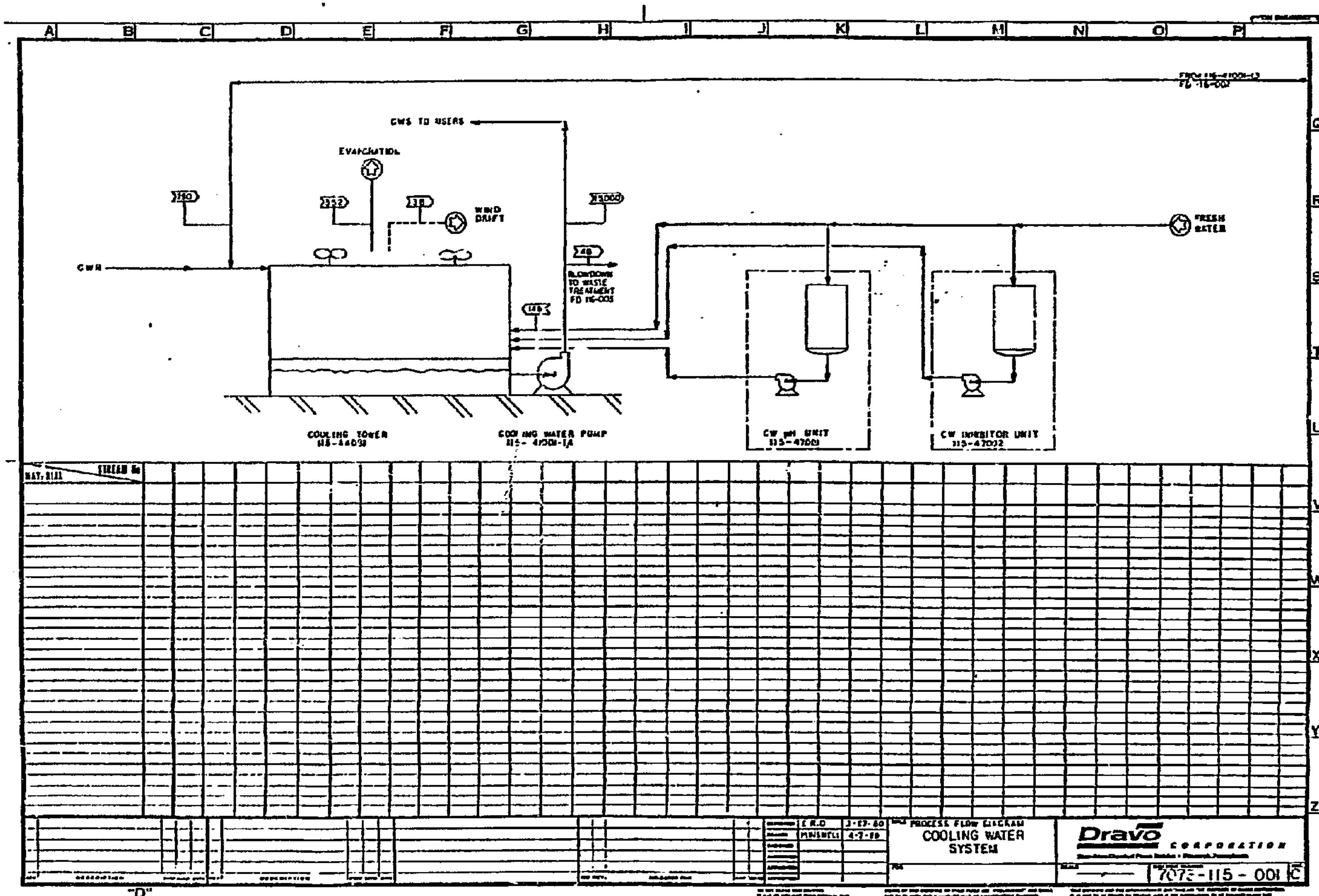
SOL 4/29/83
C. PHILLIPS 4/30/83

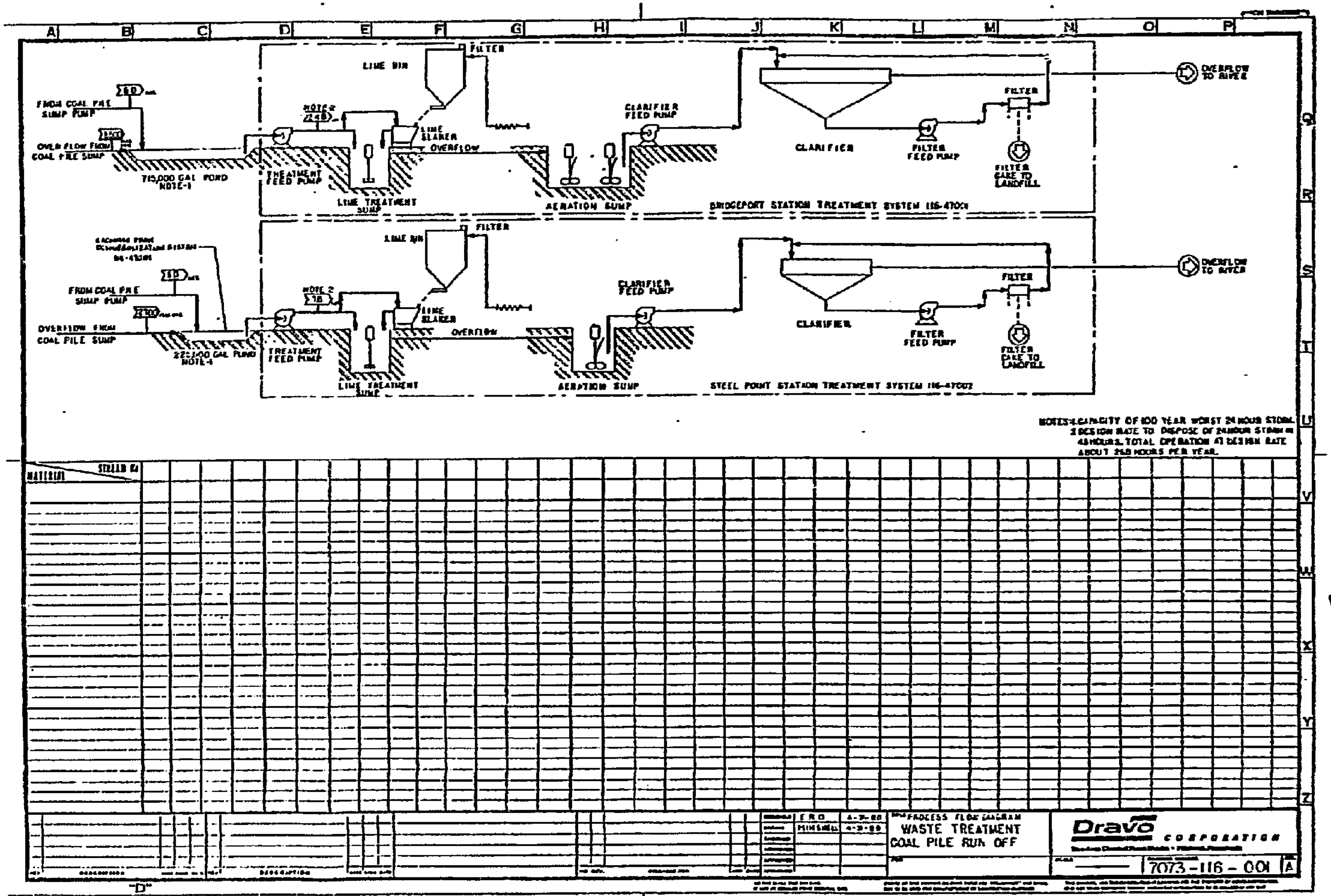
PROCESS FLOW DIAGRAM
DEMINERALIZATION

Dravo CORPORATION

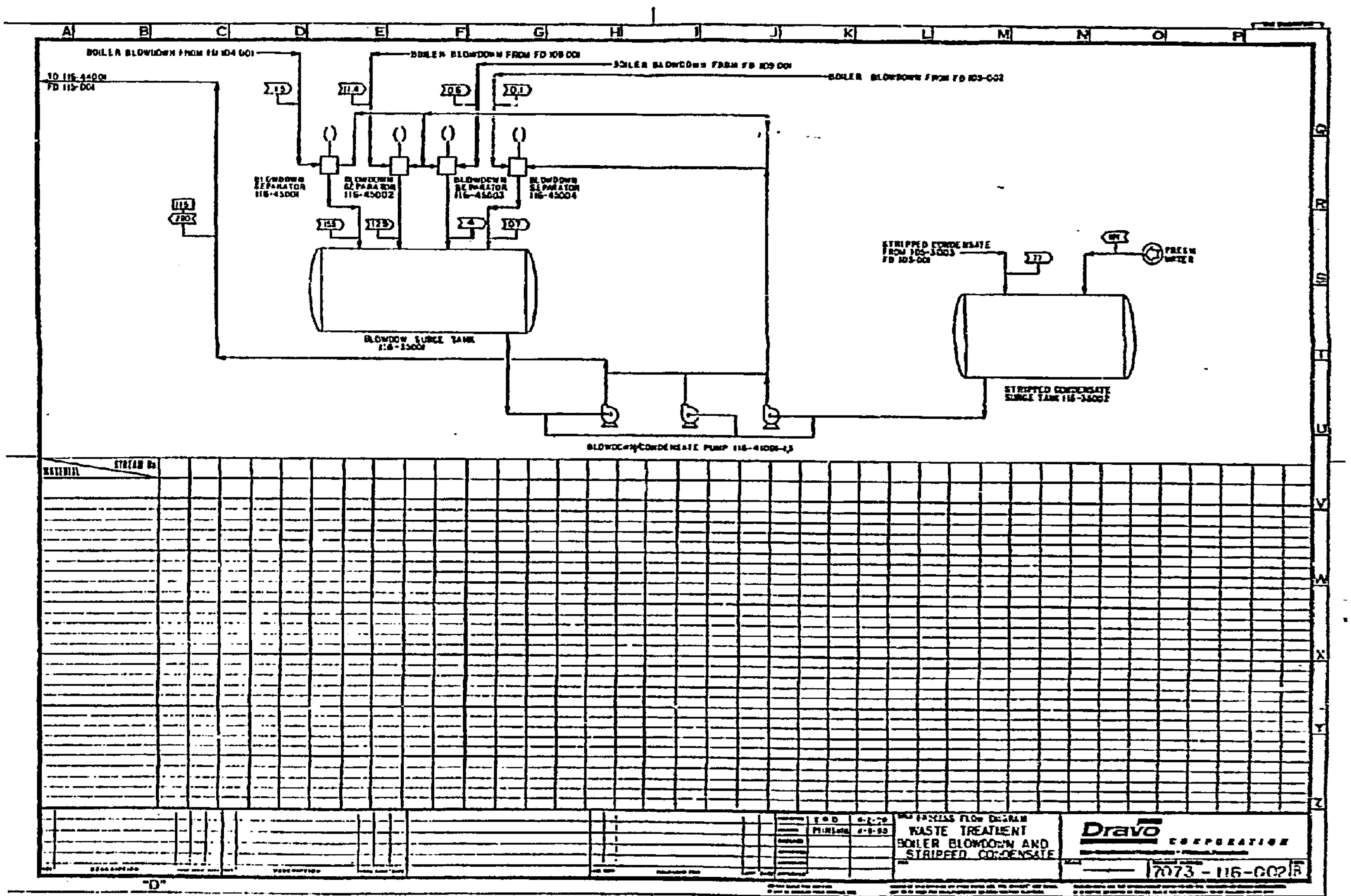
7073 H4-001 A

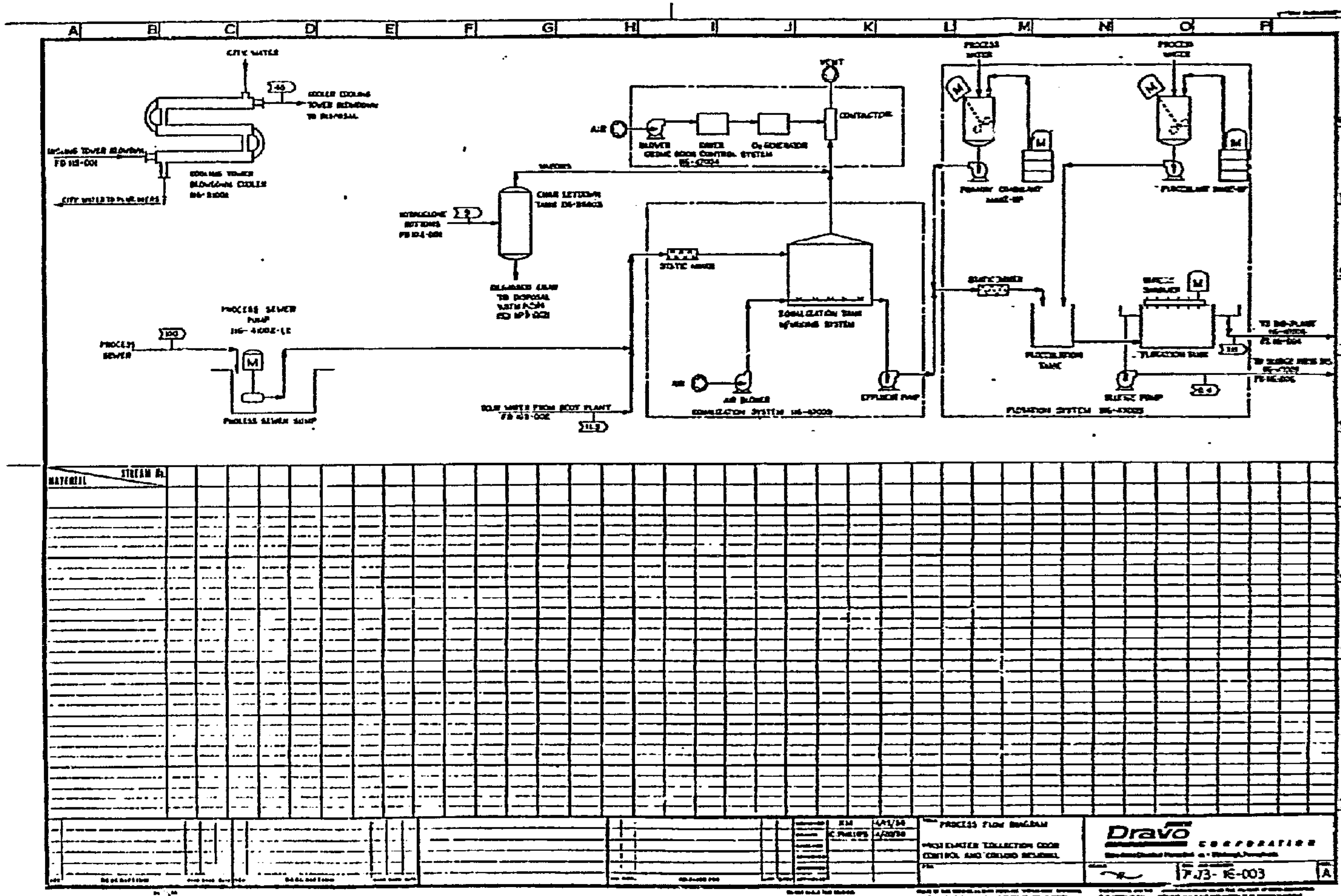
"D"

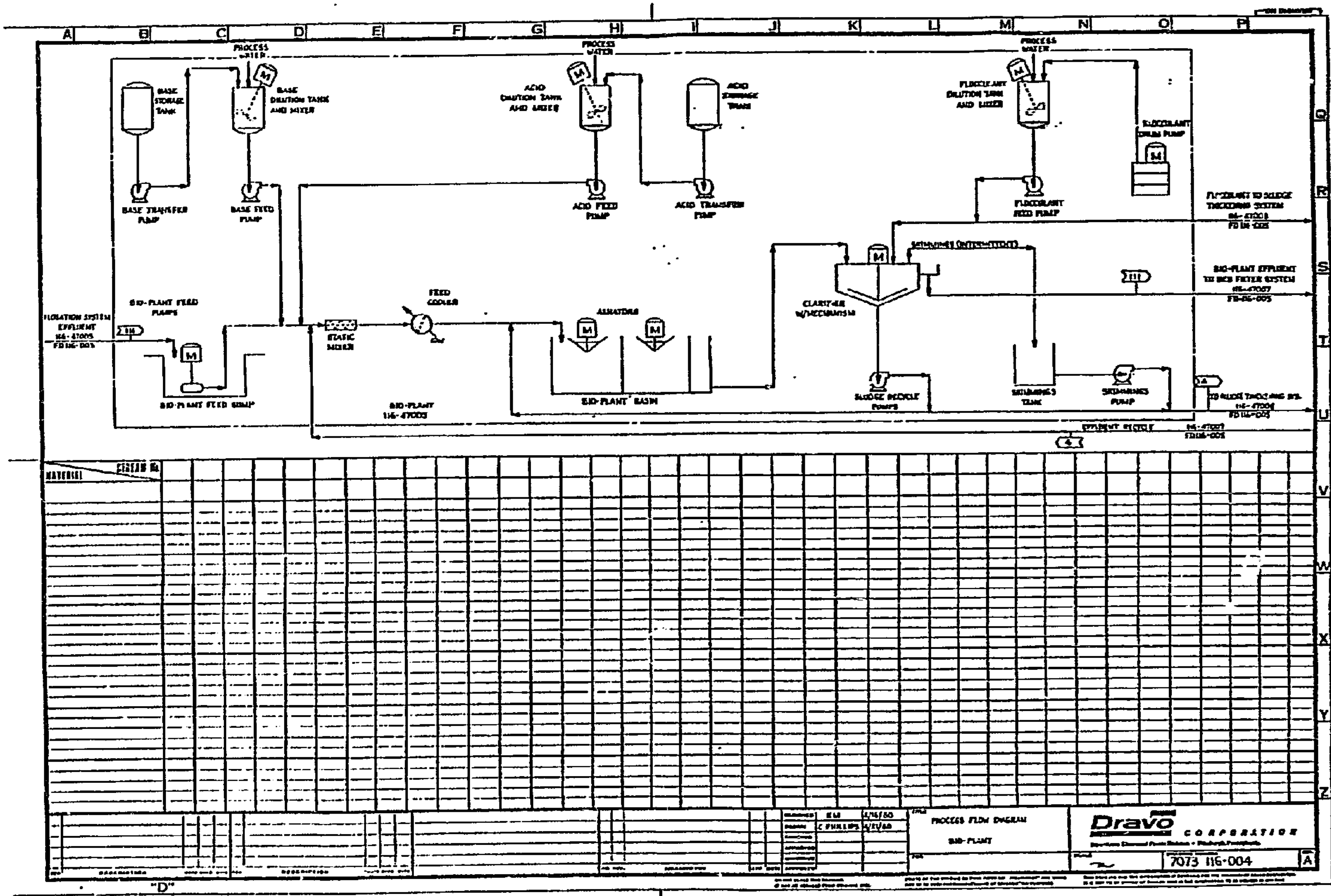

CWR
CWS TO USERS
EVAPORATION
WIND DRIFT
BLOWDOWN TO WASTE TREATMENT FD 115-003
FRESH WATER
COOLING TOWER 115-44031
COOLING WATER PUMP 115-47001-1A
CW pH UNIT 115-47001
CW INHIBITOR UNIT 115-47002
STREAM No.
MAT. BAL.
PROCESS FLOW DIAGRAM
COOLING WATER SYSTEM
Dravo CORPORATION
7072-115-001
C
"D"

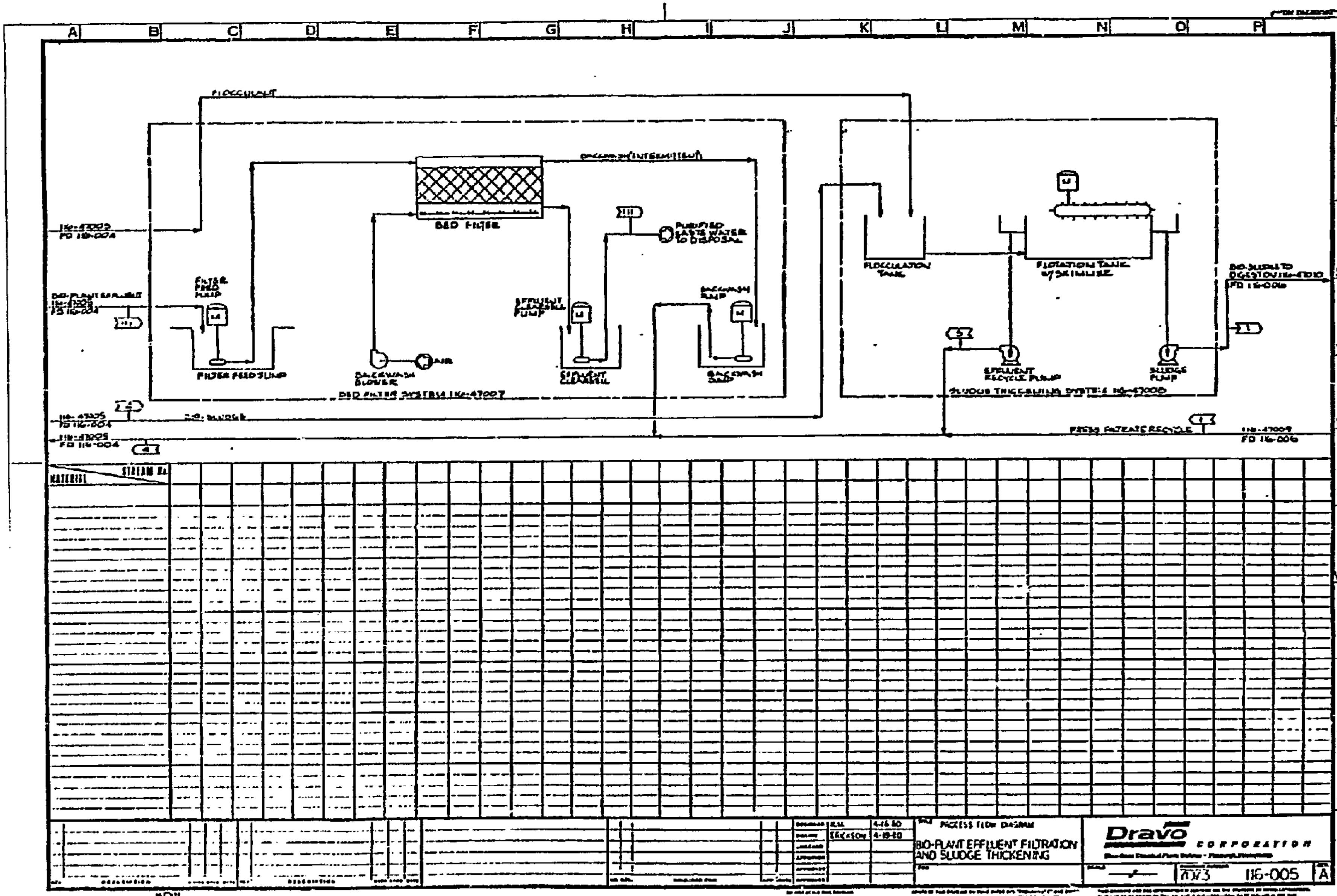


FROM COAL PILE SUMP PUMP
OVER FLOW FROM COAL PILE SUMP
715,000 GAL POND NOTE-1
NOTE 2
TREATMENT FEED PUMP
LIME BIN
FILTER
LIME SLAKER
OVERFLOW
LIME TREATMENT SUMP
AERATION SUMP
CLARIFIER FEED PUMP
CLARIFIER
FILTER FEED PUMP
FILTER CAKE TO LANDFILL
OVERFLOW TO RIVER
BRIDGEPORT STATION TREATMENT SYSTEM
FROM COAL PILE SUMP PUMP
OVERFLOW FROM COAL PILE SUMP
NOTE-1
STEEL POINT STATION TREATMENT SYSTEM
NOTES: 1. CAPACITY OF 100 YEAR WORST 24 HOUR STORM.
2. DESIGN RATE TO DISPOSE OF 24 HOUR STORM IN 48 HOURS. TOTAL OPERATION AT DESIGN RATE ABOUT 240 HOURS PER YEAR.
MATERIAL
STREAM
"D"
PROCESS FLOW DIAGRAM
WASTE TREATMENT
COAL PILE RUN OFF
Dravo CORPORATION
7073-116-001
A

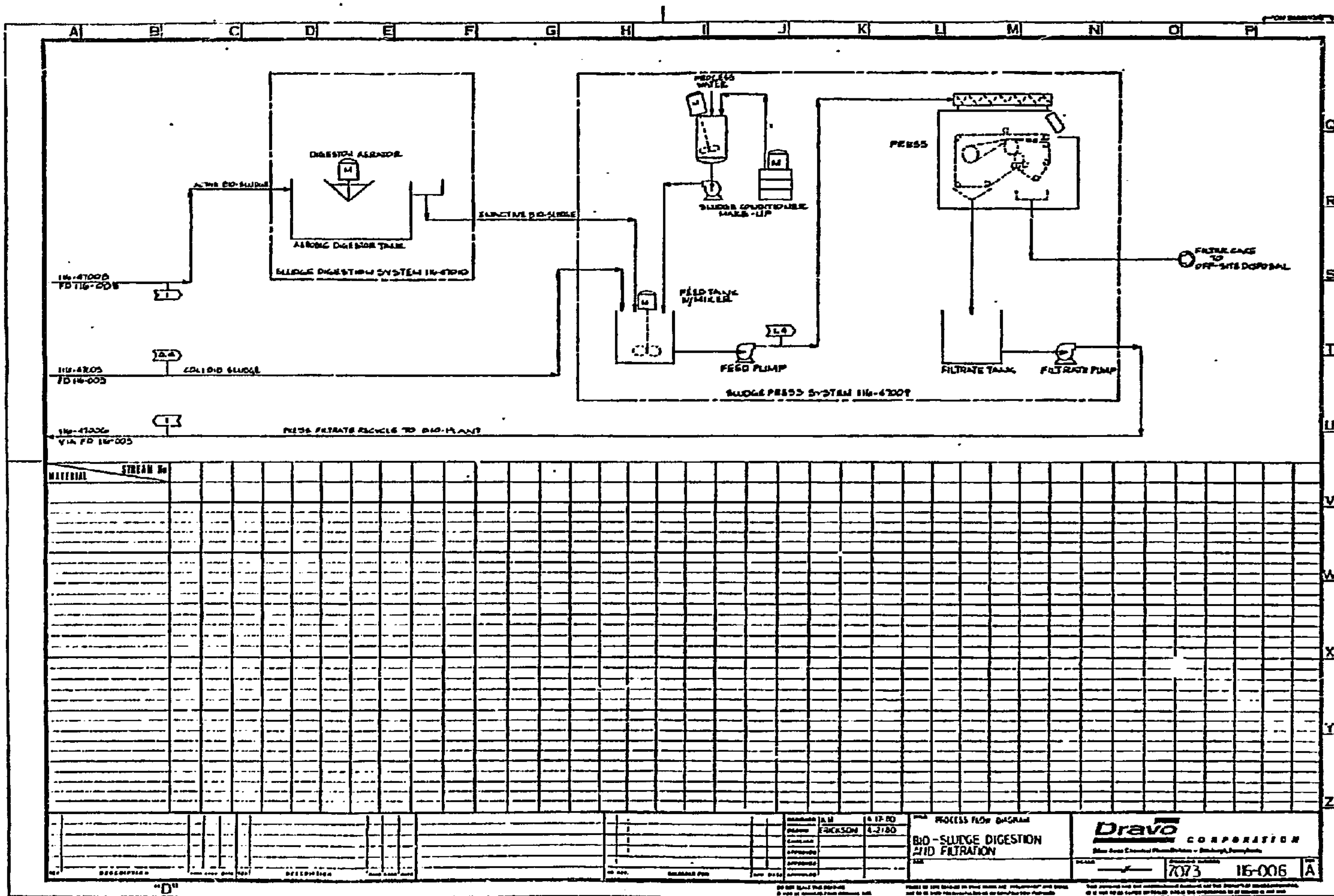

BOILER BLOWDOWN FROM FD 104 001
BOILER BLOWDOWN FROM FD 108 001
BOILER BLOWDOWN FROM FD 109 001
BOILER BLOWDOWN FROM FD 103-002
TO 116-44001
FD 113-001
BLOWDOWN SEPARATOR 116-45001
BLOWDOWN SEPARATOR 116-45002
BLOWDOWN SEPARATOR 116-45003
BLOWDOWN SEPARATOR 116-45004
BLOWDOWN SURGE TANK
STRIPPED CONDENSATE FROM 105-3003 FD 105-001
FRESH WATER
STRIPPED CONDENSATE SURGE TANK 116-35002
BLOWDOWN/CONDENSATE PUMP 116-41001-2,3
MATERIAL
STREAM No.
PROCESS FLOW DIAGRAM
WASTE TREATMENT
BOILER BLOWDOWN AND
STRIPPED CONDENSATE
Dravo
CORPORATION
7073 - 116-002
B
"D"

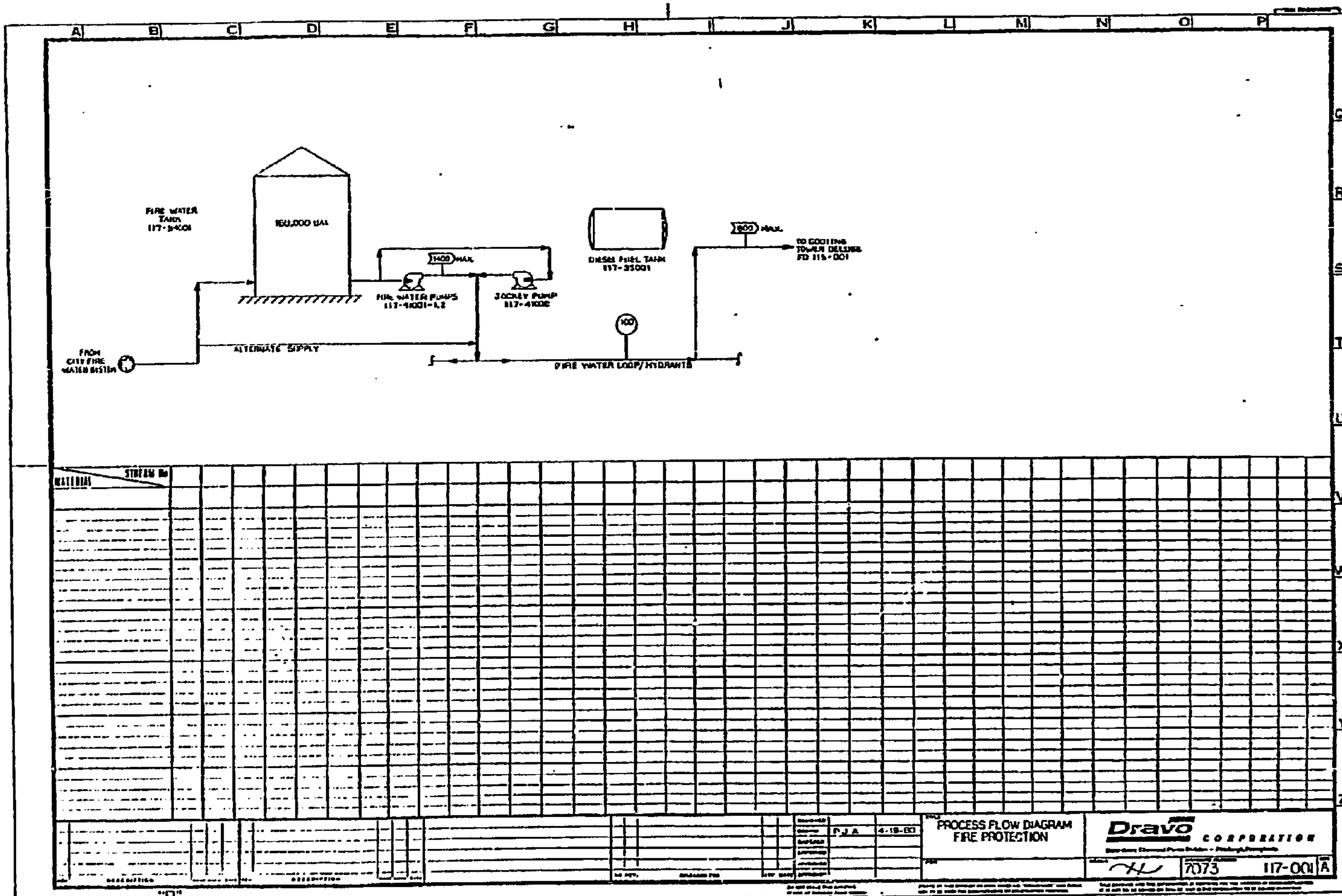

CITY WATER
AIR
VENT
CONTACTOR
BLOWER
VAPORS
STATIC MIXER
EQUALIZATION TANK
AIR BLOWER
EFFLUENT PUMP
PROCESS WATER
FLOCCULATION TANK
FLOTATION TANK
FLOTATION SYSTEM
PROCESS SEWER
PROCESS SEWER PUMP
PROCESS SEWER SUMP
STREAM No.
MATERIAL
PROCESS FLOW DIAGRAM
Dravo
CORPORATION
7J3-16-003
A

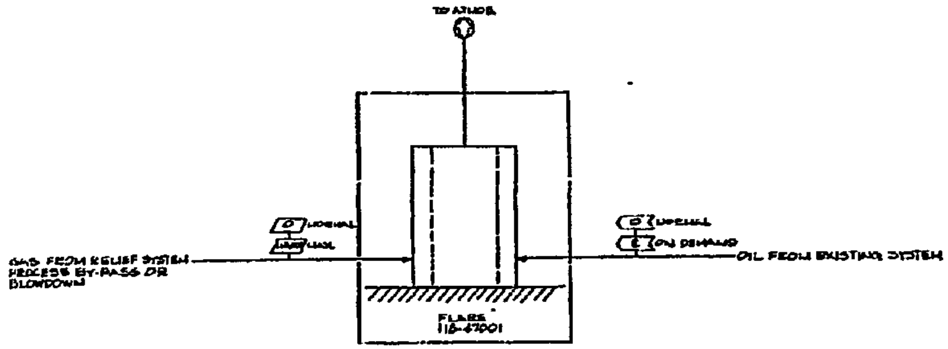

BASE STORAGE TANK
BASE DILUTION TANK AND MIXER
PROCESS WATER
BASE TRANSFER PUMP
BASE FEED PUMP
ACID DILUTION TANK AND MIXER
ACID STORAGE TANK
ACID FEED PUMP
ACID TRANSFER PUMP
FLOCCULANT DILUTION TANK AND MIXER
FLOCCULANT DRUM PUMP
FLOCCULANT FEED PUMP
FLOCCULANT TO SLUDGE THICKENING SYSTEM
BIO-PLANT EFFLUENT TO BED FILTER SYSTEM
FLOATATION SYSTEM EFFLUENT
BIO-PLANT FEED PUMPS
BIO-PLANT FEED SUMP
STATIC MIXER
FEED COOLER
AERATORS
BIO-PLANT BASIN
CLARIFIER W/MECHANISM
SKIMMINGS (INTERMITTENT)
SLUDGE RECYCLE PUMPS
SKIMMINGS TANK
SKIMMINGS PUMP
TO SLUDGE THICKENING SYS.
EFFLUENT RECYCLE
MATERIAL
STREAM No.
PROCESS FLOW DIAGRAM
BIO-PLANT
Dravo CORPORATION
7073 116-004
A
"D"



FLOCCULANT
BED FILTER
BACKWASH (INTERMITTENT)
PURIFIED WASTE WATER TO DISPOSAL
FILTER FEED PUMP
FILTER FEED SUMP
BACKWASH BLOWER
AIR
EFFLUENT CLEARWELL PUMP
EFFLUENT CLEARWELL
BACKWASH PUMP
BACKWASH SUMP
BED FILTER SYSTEM 116-47007
FLOCCULATION TANK
FLOATATION TANK W/SKIMMER
BIO-SLUDGE TO DIGESTOR 116-47010 FD 116-006
EFFLUENT RECYCLE PUMP
SLUDGE PUMP
SLUDGE THICKENING SYSTEM 116-47008
PRESS FILTRATE RECYCLE
116-47009 FD 116-006
116-47005 FD 116-004
BIO-PLANT EFFLUENT 116-47005 FD 116-004
MATERIAL
STREAM No.
PROCESS FLOW DIAGRAM
BIO-PLANT EFFLUENT FILTRATION AND SLUDGE THICKENING
4-16-80
4-18-80
Dravo CORPORATION
7073
116-005
A
"D"


DIGESTION AERATOR
ACTIVE BIO-SLUDGE
AEROBIC DIGESTOR TANK
SLUDGE DIGESTION SYSTEM 116-47010
116-47008
FD 116-008
116-47005
FD 116-005
COLLOID SLUDGE
116-47006
VIA FD 116-005
PRESS FILTRATE RECYCLE TO BIO-PLANT
PROCESS WATER
SLUDGE CONDITIONER MAKE-UP
FEED TANK W/MIXER
FEED PUMP
SLUDGE PRESS SYSTEM 116-47009
PRESS
FILTRATE TANK
FILTRATE PUMP
FILTER CAKE TO OFF-SITE DISPOSAL
MATERIAL
STREAM No
"D"
PROCESS FLOW DIAGRAM
BIO-SLUDGE DIGESTION AND FILTRATION
ERICKSON
4-21-80
Dravo
CORPORATION
7073
116-006
A


FIRE WATER TANK 117-34001
160,000 GAL
FROM CITY FIRE WATER SYSTEM
ALTERNATE SUPPLY
FIRE WATER PUMPS 117-41001-1,2
1400 MAX.
JOCKEY PUMP 117-41002
DIESEL FUEL TANK 117-35001
100
FIRE WATER LOOP/HYDRANTS
800 MAX.
TO COOLING TOWER DELUGE FD 115-001
STREAM No
MATERIAL
PROCESS FLOW DIAGRAM
FIRE PROTECTION
P.J.A.
4-18-80
Dravo CORPORATION
7073
117-001
A
"D"



MATERIAL | STREAM No.

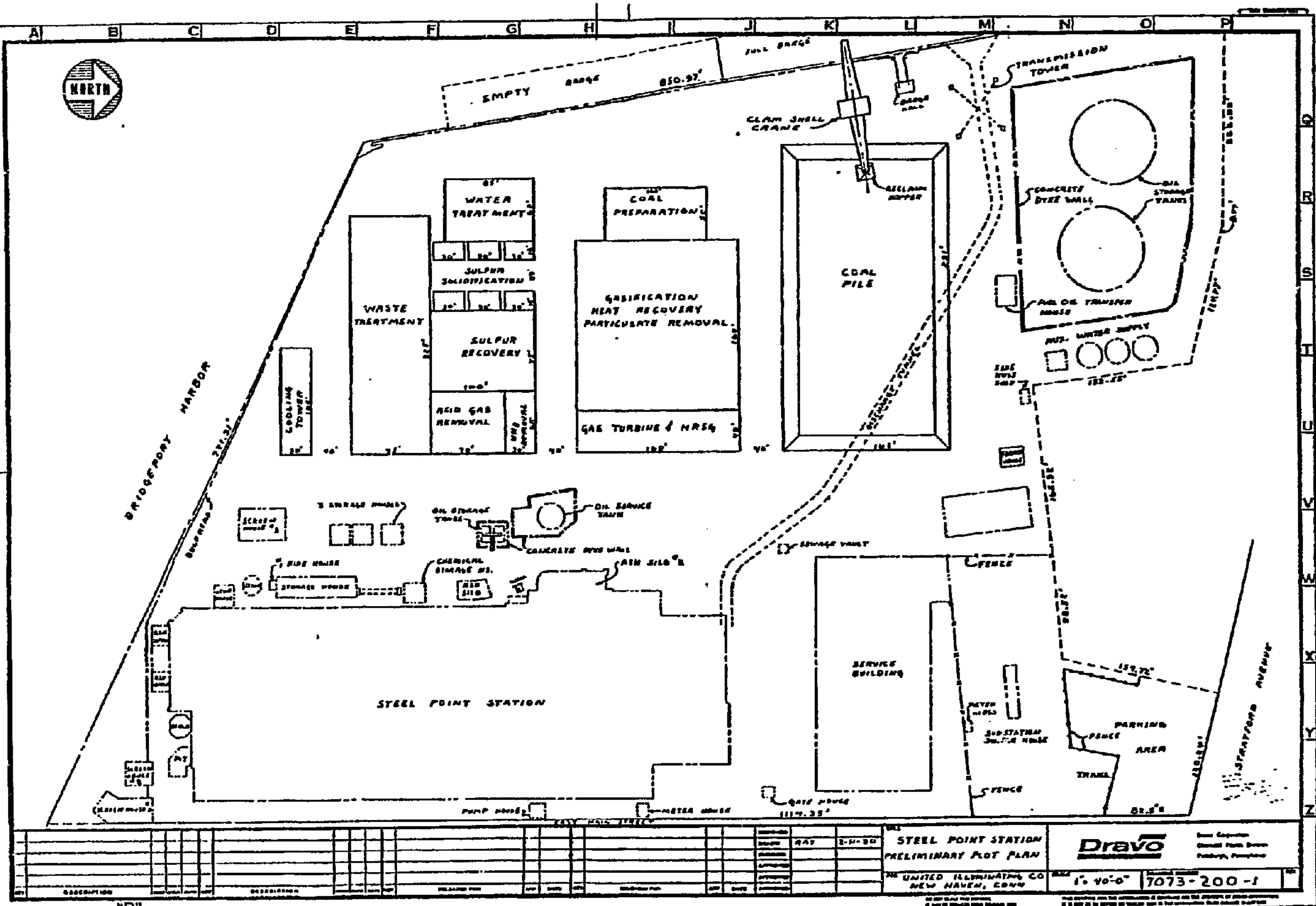
PROCESS FLOW DIAGRAM
FLARE

Dravo
CORPORATION

F.E.G. 3-26-80
ERICKSON 4-8-80

7073 118-001 A

"D"


NORTH
EMPTY BARGE 850.97'
FULL BARGE
CLAM SHELL CRANE
TRANSMISSION TOWER
RECLAIM HOPPER
COAL PILE
CONCRETE DYKE WALL
OIL STORAGE TANKS
FUEL OIL TRANSFER HOUSE
WATER TREATMENT
SULFUR SOLIDIFICATION
SULFUR RECOVERY
ACID GAS REMOVAL
WASTE TREATMENT
COOLING TOWER
COAL PREPARATION
GASIFICATION HEAT RECOVERY PARTICULATE REMOVAL
GAS TURBINE & HRSG
BRIDGEPORT HARBOR
OIL SERVICE TANK
OIL STORAGE TANKS
CONCRETE DYKE WALL
CHEMICAL STORAGE BL.
ASH SILO
ASH SILO
STORAGE HOUSE
SEWAGE VAULT
FENCE
SERVICE BUILDING
STEEL POINT STATION
SUBSTATION
FENCE
PARKING AREA
TRAIL
STRATFORD AVENUE
PUMP HOUSE
METER HOUSE
GATE HOUSE
EAST MAIN STREET
STEEL POINT STATION
PRELIMINARY PLOT PLAN
UNITED ILLUMINATING CO
NEW HAVEN, CONN
Dravo
1" = 40'-0"
7073-200-1
"D"

4.0 SYSTEM OPERATION

4.1 General Description

The power generation plant comprises a 108 MW combustion turbine-generator unit and facilities for producing steam to drive two existing steam turbine-generators, Units Nos. 9 and 11. The boilers which presently supply steam for Units 9 and 11 will be idle when the gasifier complex is in operation, but they will remain available and interconnected for operation, if required.

The combustion turbine will be fueled with low Btu gas from the gasifier during normal operation. Light distillate oil would be fired for startup. Steam generated in the exhaust heat recovery steam generator would be used to start and bring the gasifier into operation, and the product gas would be burned as it became available.

Steam System Diagram, Figure 4-1 shows the principal piping systems. Cross-connections for startup purposes are not shown. Steam is generated and superheated in both the gas cooler and the heat recovery steam generator. The gas cooler, which is located in the gasification facility, receives the raw gas from the gasifier at 1850°F and cools it to about 350°F before scrubbing and treatment. The lower temperature end of the gas cooler houses the fuel heater in which the product gas is reheated to 500°F and supplied to the combustion turbine. The heat recovery steam generator receives the combustion turbine exhaust at 1030°F under full load conditions and standard ambient temperature. The exhaust temperature varies with combustion turbine load and ambient temperature.

A single deaerator receives condensate from the steam turbine-generator units and other sources, wherein it is both heated and degasified. Feedwater from the deaerator is pumped through the economizer located in the heat recovery steam generator. Leaving the economizer the flow divides between the two evaporator sections, one in the heat recovery steam generator, the other in the gas cooler. Saturated steam from both evaporator sections passes through the primary superheater located at the high temperature area of the heat recovery steam generator. Leaving the primary superheater, the flow divides and passes through either of the two final superheaters in the gas cooler. Location of the final superheaters in the gas cooler assures that high steam temperature is available under a wide range of load conditions because the fuel gas temperature varies only slightly with relatively large load changes; see Figure 4-2.

Steam is supplied at two pressure-temperature levels to meet turbine throttle conditions as follows:

4.1 General Description (Cont'd.)

900 psi system - provides steam at 850 psig, 900°F for existing No. 11 turbine-generator, and for the turbine driver of the booster compressor which serves the gasifier.

700 psi system - provides steam at 625 psig, 850°F for the existing No. 9 turbine-generator and for the gasifier.

A single pressure steam generating (evaporating) system is provided to avoid restrictions on the operation of the gasifier or the gas turbine when either No. 9 or No. 11 Unit is out of service. For maximum flexibility, the system generates steam at the 900 psi 900°F level, using a pressure regulating-desuperheating station before the final superheater to supply the 700 psi 850°F steam. The desuperheating (attemperating) control supplied before the final superheaters is considered necessary to prevent excessively high-steam temperature. This is a widely used method of control and is well suited for this application.

Alternatively, steam could be generated entirely at the lower pressure. However, the flow through the No. 11 turbine, which is designed for 850 psi 900°F throttle conditions, would thereby be reduced. The reduction in flow, and the lower heat content of the steam would reduce the heat removal capacity in the gas cooler and thus limit the production of the gasifier to approximately 75%. The combustion turbine would correspondingly be reduced in load. This mode of operation would set the design condition for the combined cycle, thereby limiting system capability and significantly increasing the heat rate. Therefore, it is concluded that generating the steam at the higher pressure conditions is more desirable.

Existing turbine-generator Units Nos. 9 and 11, are presently arranged for regenerative feedwater heating. For the proposed application only the lowest pressure extraction would be used, and the higher extractions shut off. In contrast with the usual regenerative cycle, the higher feedwater temperature would not reduce the fuel consumption in the steam generator but would only increase the heat loss to the atmosphere. In this cycle, heat gain is achieved by heat recovery from hot exhaust gases and not fuel addition as in a conventional boiler.

The turbine-generator Units, Nos. 9 and 11, are nominally rated at 25 and 33 MW, respectively, in conventional regenerative feedwater heating cycles. Capability of each unit is higher than the nominal rating, however, the manufacturer has recommended that the steam flow through the lowest pressure stage be limited to 225,000 lb. per hour for each turbine. With this limitation, the full load output for these units, in the heat recovery cycle, is calculated to be 29.9 MW for Unit No. 9 and 30.8 MW for Unit No. 11.

4.1 General Description (Cont'd.)

There are two topping turbine-generator units at the Steel Point Station which are designed to operate with throttle steam at 625 psig, 850°F, exhausting to a 225 psi system. The use of these units has not been considered in the present study, however, these could be used to improve the heat rate as described under Case II below or to provide a cogeneration heat source.

4.2 Operating Cases

The product gas generated by the gasifier will supply the full load requirements of the combustion turbine unit. The steam production under these conditions will exceed the combined capability of the existing steam turbine-generators and the needs of the gasifier complex. Quantitatively, the "rated" electrical output of the combined cycle will correspond to 91.4% of the design capability of the gasifier and combustion turbine unit. In essence, the gasifier and combustion turbine would be operating under derated conditions, enhancing reliability and availability. During actual design it may be possible to optimize the overall load requirements. This type of operation is also compatible with cogeneration district heating applications.

Listed in Table 4-1 are the six operating cases chosen for study. They range from maximum electrical generation with all turbine-generators operating at full load to limited operation and operation of the combustion turbine on distillate fuel. Included in that tabulation is the heat rate calculated for each case.

TABLE 4-1
OPERATING CASES

Case No.	Description	Heat Rate
I	Steam turbine-generator Unit Nos. 9 and 11 at full load with the gasifier and combustion turbine at matching load.	9,902 Btu/KWh
II	Maximum generation; all turbine-generators operating at full load	10,133 Btu/KWh
IIIA	Combustion turbine at minimum load with steam turbines No. 9 and No. 11 at match load.	11,200 Btu/KWh
IIIB	Unit No. 9 out of service	12,300 Btu/KWh
IV	Gasifier and combustion turbine at full load with partial bypass of the heat recovery steam generator with No. 9 and No. 11 at design full load.	10,211 Btu/KWh

4.2 Operating Cases (Cont'd.)

Case No.	Description	Heat Rate
V	Gasifier out of service with the combustion turbine at full load on distillate fuel with No. 9 and No. 11 at design full load.	7,837 Btu/KWh

What follows is a more detailed description of the operating cases.

4.2.1 Case I:

Steam turbine-generator Unit Nos. 9 and 11 at full load, with the gasifier and gas turbine at matching load.

The gasifier and gas turbine would operate at 91.4% of their design capabilities with no surplus production of steam.

The performance is estimated as follows:

Gas Turbine-generator	98,512 KW
Steam TG No. 9	29,905
Steam TG No. 11	30,800
Gross	159,217 KW
Auxiliary Power	7,240
Net	151,977 KW
Net Heat Rate	9,902 Btu/KWh

4.2.2 Case II:

Maximum production; all turbine-generators operating at full load.

By operating the combustion turbine-generator at the rating of 107,782 KW, surplus steam is produced. However, this steam could be used in the two existing topping turbines at Steel Point. In any case, the disposition of the surplus steam must be reviewed by United Illuminating Co., evaluating* the credit for heat removal from the combined cycle.

*U. I. has adjusted these figures slightly to take advantage of the excess steam by increasing No. 11 Unit output consistent with current operating levels.

4.2 Operating Cases (Cont'd.)

Alternatively, it could be possible to bypass part of the gas turbine exhaust, thereby reducing the steam production in the heat recovery steam generator and increasing steam production in the gas cooler. The resulting loss of efficiency would be partially compensated by the resulting increase in electrical generation of the gas turbine-generator. This alternate would involve maximum electrical production with limited steam production and is discussed under Case IV.

To demonstrate the case of maximum electrical and steam production, the topping turbine scheme is considered as follows.

Assigning a steam rate of 47 lb/KWh to the topping turbines and with a steam surplus of 58,142 lb/hr at 700 psi, 1,237 KW would be generated.

The performance is estimated as follows:

Gas Turbine-Generator	(100%)	107,782 KW
Steam Turbine-Generator No. 9		29,905
Steam Turbine-Generator No. 11		30,800
Topping Turbines		1,237
Gross Output		169,724 KW
Auxiliary Power		7,240
Net		162,484 KW

$$\text{Net Heat Rate} = \frac{1646.55 \times 10^6}{162484} = 10{,}133 \text{ Btu/KWh*}$$

*The economics might be improved by credits for use of the topping turbine exhaust or by sale of the surplus steam for other uses such as cogeneration district heating.

4.2.3 Case III: Limited Operation

4.2.3.1 Case III A:

Combustion turbine at minimum load with steam turbines No. 9 and No. 11 at match load.

Partial load performance cannot be determined with great accuracy at this conceptual stage of design, accordingly only a preliminary estimate can be made. In general, the heat available in the gas cooler is directly proportioned to the

4.2 Operating Cases (Cont'd.)

throughput, or volumetric output, of the gasifier, since the temperature of gas leaving the gasifier remains nearly constant. In the heat recovery steam generator, the inlet gas temperature and mass flow decreases as the load is reduced, while the exit gas temperature remains nearly constant. The total heat available is about proportional to the gas turbine load. The lower inlet temperature through the heat recovery steam generator, however, reduces the saturated steam temperature and pressure.

For study purposes, it is assumed that both steam turbine Units, Nos. 9 and 11, could operate with steam at about 400 psi, 750°F and generate a total of 40,000 KW. This would correspond to about a 65% combustion turbine-generator output. The auxiliary load would be only slightly reduced, so that the total net generation would be about 103,000 KW at a heat rate of 11,200 Btu/KWh. This represents the low estimate for continuous operation of the combined cycle.

4.2.3.2 Case III B

Unit No. 9 out of service.

Steam flow would be lower than in Case III A with slightly higher pressure. If it were possible to generate steam at 900 psi, 900°F, the gasifier would operate at about 53.5% load and the gas turbine at about 43.5% load. Net generation would at about 71,600 KW and heat rate about 12,300 Btu/KWh. Since it is not certain that the full steam pressure and temperature could be achieved, this performance must be considered as an approximation.

4.2.4 Case IV:

Gasifier and combustion turbine at full load with partial bypass of the heat recovery steam generator.

In this case, steam production is limited to that required for full load operation of both Units No. 9 and 11. To do this, about 15% of the gas turbine exhaust is bypassed around the heat recovery steam generator. Both the gasifier and the combustion turbine-generator operate at full load.

4.2 Operating Cases (Cont'd.)

The performance is estimated as follows:

Gas Turbine-Generator	107,782 KW
Steam Turbine-Generator No. 9	29,905
Steam Turbine-Generator No. 11	30,800
Gross Output	168,487 KW
Auxiliary Power	7,240
Net	161,247 KW
Net heat rate $\frac{1646.56 \times 10^6}{161,247}$ =	10,211 Btu/KWh.

4.2.5 Case V:

Gasifier out of service with the gas turbine at full load on distillate fuel.

The combustion turbine operating on distillate would generate less power than when firing the gas. Its exhaust temperature would also be lower. Further, since the gas cooler and final stage superheaters would not be in service, the final steam temperatures would be lower.

The performance is estimated as follows:

Gas Turbine-Generator	94,318 KW
Steam Turbine-Generators No. 9 and 11	47,300
Gross Output	141,618 KW
Auxiliary Power	2,590
Net	139,028 KW

Fuel required: 56,456 lb. per hour distillate at 19,300 Btu/Lb. (HHV)

Net Heat Rate = 7,837 Btu/KWh (HHV)

4.3 Partial Loads and Operational Limits

As indicated in the operating cases above, the partial load and off-normal operation cannot be predicted accurately until more definitive design data can be developed. Based on the above, however, the Gasifier-Combined Cycle can be designed and constructed for operation as a scheduled generating unit in a utility system.

4.3 Partial Loads and Operational Limits (Cont'd.)

It is not recommended that this system be used for peaking purposes as the sudden swings in demand experienced in this type of service cannot be followed by the gasification system. The system is capable of following slower changes in demand within the limits of the turndown capacities of the gasifiers, combustion gas turbine and steam turbine generators. In general, operating the CG/CC system at less than full load is not recommended as there is a substantial cost penalty when the system runs at less than full load or is shut down intermitantly.

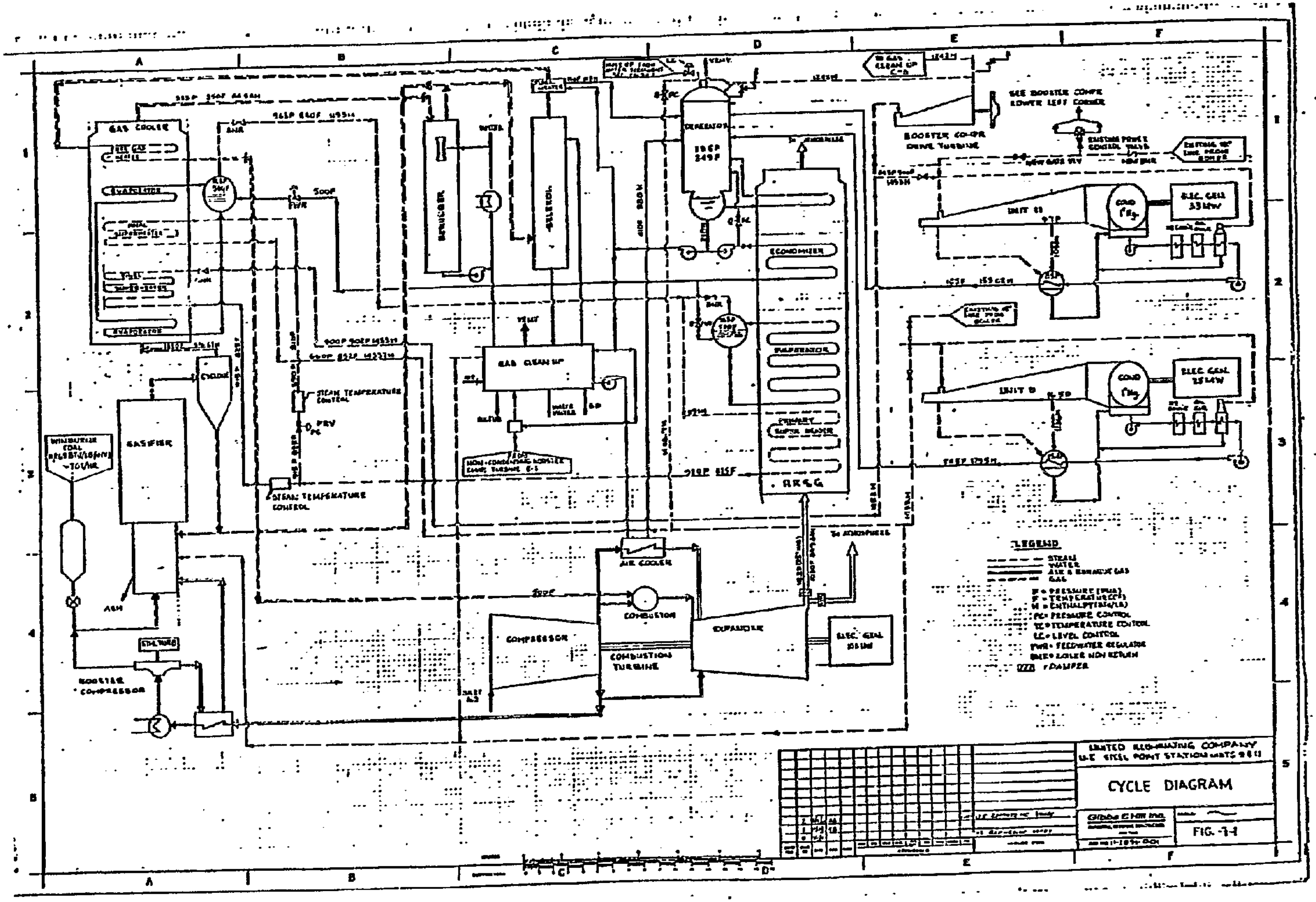
4.4 Startup and Shutdown

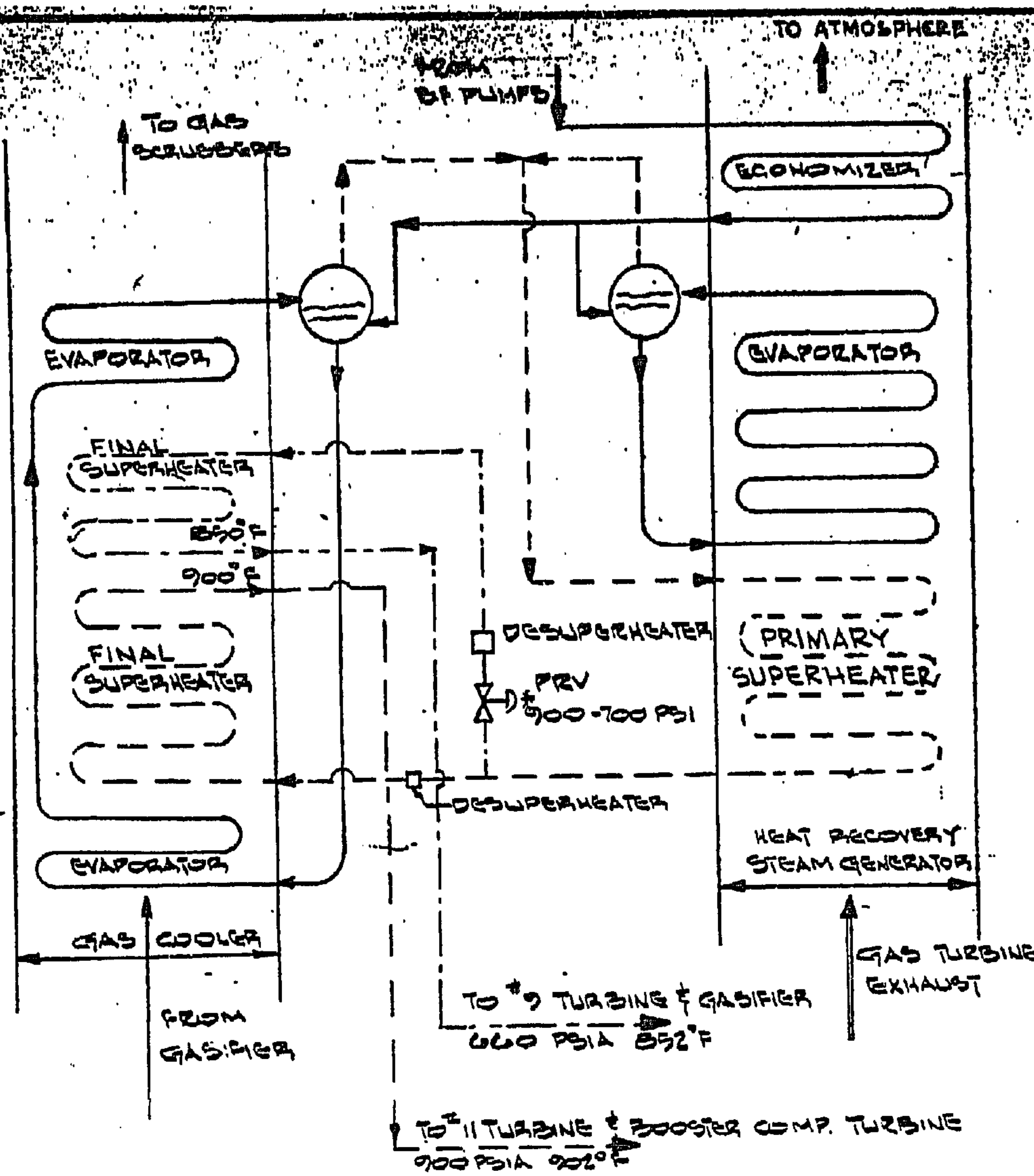
It is expected that energy for auxiliary drives and for the gas turbine starting equipment will be available from the existing 13.8 KV switchyard; see Main One Line Diagram, Figure 3.5-1.

The gas turbine will be brought up to firing speed by its electric starting motor and fired using light fuel oil. The unit is designed to start and accept full load in 10 minutes. Within about 2 hours, steam will be generated in the heat recovery steam generator for use in the gasifier. The gasifier will require about one hour to achieve steady state conditions. During the interim, sufficient steam should be available from the heat recovery steam generator to start turbine generators Units Nos. 9 and 11. As the gasifier output increases, the gas turbine uses more gas and less oil, eventually firing gas only.

For scheduled shutdown, the gasifier production would be gradually reduced, with the gas turbine firing oil, if required, to maintain stable steam conditions during the shutdown.

The gasifier can be banked, if required during minimum system load conditions. For short shutdowns of 36 hours or less, the gasifier loses little heat and can be brought back on line within two hours. For longer shutdowns, the restart time increases as the gasifier temperature lowers. After a couple of days, the refractory cools enough that it will take about eight hours to reheat. On any shutdown, the coal inventory within the gasifier is lowered to a level below the air injector points. Restart of the system would require some fuel oil, but the startup period would be shorter if the steam side was held on hot shutdown to maintain temperature.


GAS COOLER
GASIFIER
CYCLONE
BOOSTER COMPRESSOR
SCRUBBER
GAS CLEAN UP
DEAERATOR
ECONOMIZER
EVAPORATOR
HRSG
AIR COOLER
COMBUSTOR
COMPRESSOR
COMBUSTION TURBINE
EXPANDER
ELEC. GEN.
BOOSTER COMPR DRIVE TURBINE
SEE BOOSTER COMPR LOWER LEFT CORNER
UNIT 8
UNIT 9
COND
STEAM TEMPERATURE CONTROL
LEGEND
STEAM
WATER
AIR & EXHAUST GAS
GAS
P = PRESSURE (PSIA)
F = TEMPERATURE (°F)
H = ENTHALPY (BTU/LB)
PC = PRESSURE CONTROL
TC = TEMPERATURE CONTROL
LC = LEVEL CONTROL
FWR = FEEDWATER REGULATOR
BNR = BOILER NON RETURN
DAMPER
UNITED REFINING COMPANY
CYCLE DIAGRAM
FIG. 1-1



- - - - - - STEAM
———————— WATER

5/15/80

* PRV IS SCHEMATIC ONLY TWO CONTROL VALVES WITH SAFETY VALVE PROTECTION AND POSSIBLE BYPASS FOR LIGHT LOAD (LOW PRESSURE) OPERATION SHOULD BE CONSIDERED

UNITED ILLUMINATING COMPANY
GASIFICATION COMB. CYCLE U.I. STEEL PT. STA UNITS 9/11

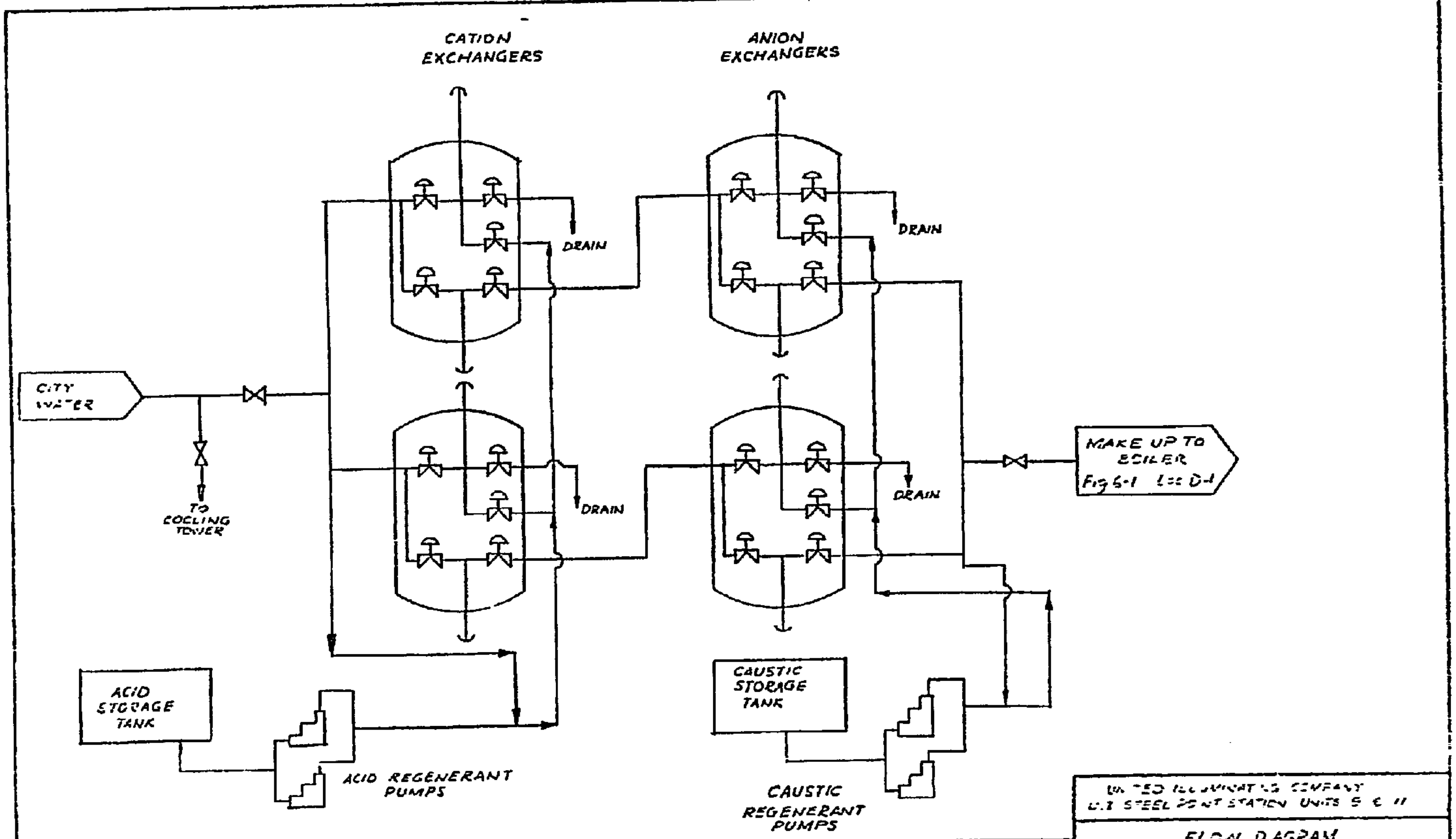
DETAIL
STEAM GENERATION

Gibbs & Hill, Inc.
ENGINEERS, DESIGNERS, CONSTRUCTORS
NEW YORK

SCALE:- NONE

FIGURE 4-2

DRG NO. 11-2891-001



U.T. REPOWERING STUDY

U.T. REPOWERING STUDY

ISSUED FOR

APPROVALS

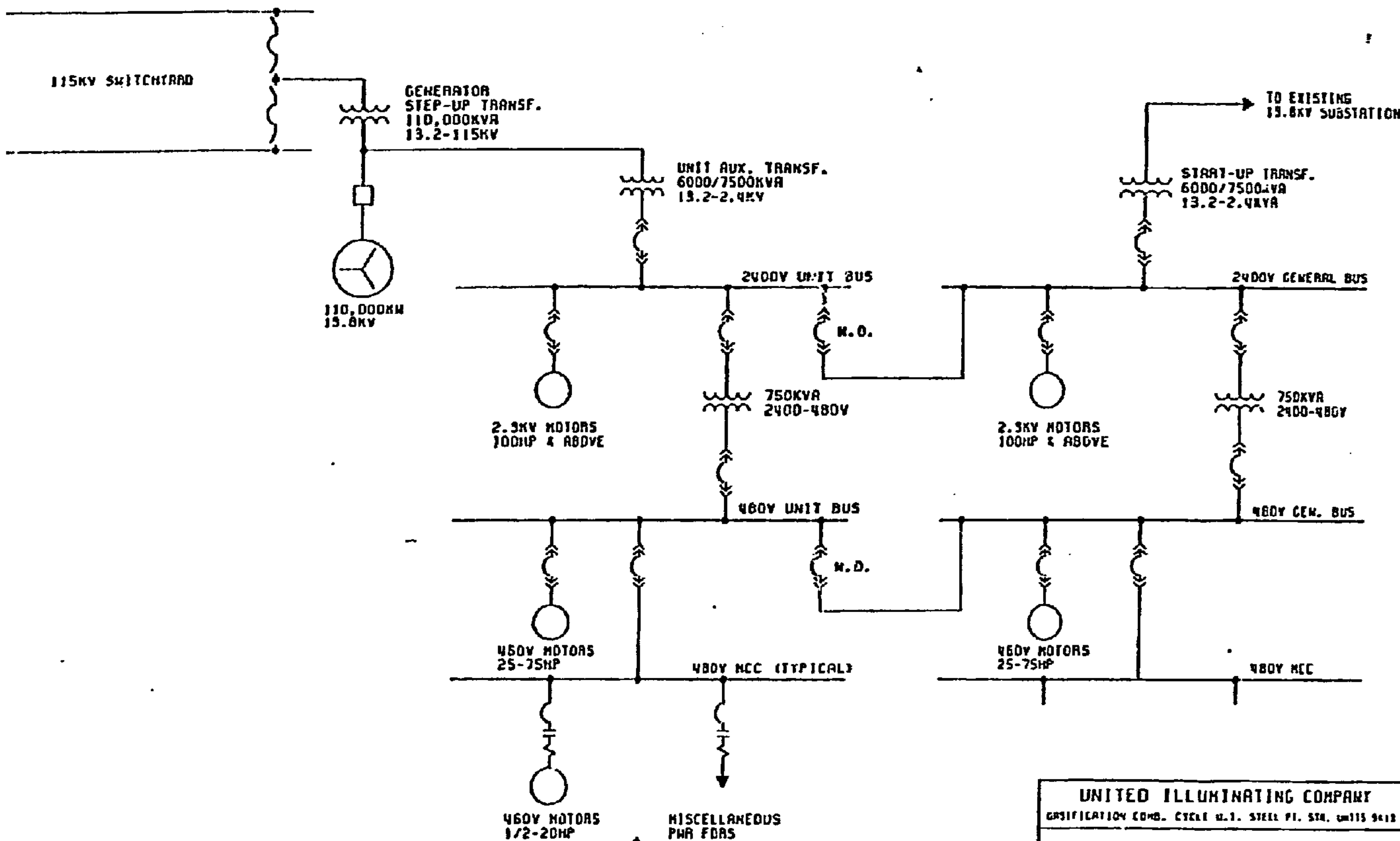
Gibbs & Hill Inc.

JOB NO 11-2891-001

FLOW DIAGRAM

WATER TREATMENT SYSTEM

FIG. 3.4-1



UNITED ILLUMINATING COMPANY
GASIFICATION COMB. CYCLE U.I. STEEL PT. STA. UNITS 9&10

MAIN ONE LINE DIAGRAM

Gibbs & Hill Inc.

SCALE: —

JOB NO. 11-2891-001

FIG. 3.5-1

MICRO FILM	ISSUE NO.	DATE	DWN.	CHKD.	ARCH	STR.	MECH	ELEC		I&C	SHLD	CONST	P.M.	ISSUED FOR
	1	1/15/85	H.P.	-				VJP						U.I. REPOWERING STUDY
														U.I. REPOWERING STUDY

5.0 ENVIRONMENTAL LICENSING CONSIDERATIONS

This section describes the permits and licenses required to install coal gasification at the Steel Point Station (SPS). Also, the project is briefly described with respect to environmental constraints and requirements of the necessary permits.

5.1 Air Quality

5.1.1 Emission Loads

The coal gasification facility including the gas turbine-generator and heat recovery boiler would result in controlled emissions as follows:

Source	Emissions	Quantity
a) Coal Preparation	a. Fugitive Dust	Depends on Conn's Emission Factors[1]
	b. Sulfur Dioxide (When coal dryer is utilized, quantity of air used ranges from 7,441 to 20,000 SCFM)	115 ppm @ 7,441 SCFM (8.3 lb/hr) 98 ppm @ 20,000 SCFM (19.1 lb/hr)
b) Waste Heat Steam Generator		
a. Deaerator Vent	Steam & Inerts	3,000 lb/hr
b. Main Vent	Sulfur Dioxide	46 ppm (279 lb/hr; 0.23 lb/10^6 BTU)
	Char fines	0.005 $\frac{\text{grains}}{\text{SCFM}}$ (27 lb/hr)
	Air	640,253 SCFM
c) Sulfur Recovery		
a. Feed Heater Vent	Air SO2	862 SCFM 104 ppm (0.87 lb/hr; 0.077 lb/10^6 BTU)
b. Incinerator Vent	Air SO2	6887 SCFM 181 ppm (12.2 lb/hr; 108 lb/10^6 BTU)

1. Fugitive emissions will be minimal because coal is being barged to SPS and because Best Control Technology (BEST) will be used at all points

5.1 Air Quality (Cont'd.)

5.1.1 Emission Loads (Cont'd.)

Source	Emissions	Quantity
d) Cooling Tower		
a. Wind Drift	Water Vapor	38 GPM
b. Evaporation Loss	Water Vapor	352 GPM

5.1.2 Permits and Regulations

5.1.2.1 Federal

(a) New Source Review

Pursuant to Section 111 of the Clean Air Act, the USEPA has established national New Source Performance Standards (NSPS) (i.e., maximum allowable pollutant emission standards) which would apply to UI's coal gasification system. The applicable NSPS cover: a) gas turbines; b) steam-electric generating plants; and c) coal dryers.

New source performance standards (NSPS) for coal gasification plants have not been established. However, USEPA's Office of Air Quality Planning and Standards in Durham, NC will propose low-BTU Coal Gasification Regulations in January, 1982. Medium and High BTU Regulations will follow later.

Federal NSPS for gas turbines(September 10, 1979) would apply to the combined cycle-electric generating plant which would burn the gas produced by the coal gasifier. However, if supplemental fuel is fired in the heat recovery boiler at 250 x 10^6 Btu/hr, or more, then the NSPS for steam-electric plants (June 11, 1979) would apply.

Table 5-1 presents the appropriate NSPS for UI's gas turbine.

Federal law also requires that all new major stationary sources use the Best Available Control Technology, BACT, to substantially reduce emissions.

TABLE 5-1

NEW SOURCE PERFORMANCE STANDARDS (NSPS)
FOR GAS TURBINES (WHERE HEAT INPUT > 100 MMBtu/Hr.
(adopted in Conn.'s SIP)

Constituent	Emission Limit (ppm)
Nitrogen Oxides, NOx	75[2]
Sulfur Dioxide, SO2	150

1. NSPS for Gas Turbines took effect on 10/3/77.

2. This emission limit is referenced to 15% O_2 (dry basis).

5.1 Air Quality (Cont'd.)

5.1.2 Permits and Regulations (Cont'd.)

5.1.2.1 Federal (Cont'd.)

(b) Prevention of Significant Deterioration (PSD) Permit

Prevention of Significant Deterioration regulations (40 CFR 52) of August 7, 1980, require a pre-construction review and permit process for all new sources with the potential to emit 250 tons per year (TPY) of a regulated pollutant, and 28 specific new source categories with the potential to emit 100 TPY. The proposed SPS coal gasification system will emit over 250 TPY of SOx and NOx, and is, therefore, subject to PSD review.

The PSD regulations have also established maximum levels of sulfur dioxide (SO2) and particulates for different geographical areas designated as Class I, II, or III. Allowable increments in Class I areas severely restrict any industrial growth, increments in Class II areas allow moderate growth while increments in Class III areas permit the most industrial growth. Table 5-2 lists the allowable PSD increments.

Under PSD review, the applicant may be required to: Perform extensive ambient air quality monitoring; provide models predicting dispersion of emissions; demonstrate that the proposed emissions will use only a portion of the available PSD increment; assess the direct efects on visibility, soils and vegetation; and demonstrate that BACT will be applied.

"Offset" reductions are required for a major new source of pollutant which is to be located in an area that is non-attainment for the pollutant. (Such as is the cash for TSP in the Bridgeport Area). Where the area is in attainment, new source pollutants cannot cause the NAAQS to be exceeded, or cause an increase in ambient concentrations over the allowable "PSD" increment.

Bridgeport is in an area categorized as a "Class II" PSD area for which the allowable increments are as presented in Table 5-2. No PSD applications for a new source in CT. have been filed. However, if this project were to proceed, further air quality analysis would be required for this Bridgeport area.

Based upon Connecticut's Legislative Regulatory Review Committee's analysis of PSD regulations, Connecticut decided not to submit a PSD program within its SIP revisions. Connecticut has nine months from the date

5.1.2 Permits and Regulations (Cont'd.)

5.1.2.1 F deral (Cont'd.)

of the current PSD regulations (8/7/80) to introduce its own PSD program. Otherwise, USEPA-Region I will continue to be the PSD agency for Connecticut.

On 7/2/80, USEPA issued a Notice of Proposed Rulemaking on Connecticut's revised SIP, which was submitted in four installments of over 1000 pages in the period 6/79-5/1/80. Final Rulemaking is expected by 1/81. USEPA has four options:

a) Approve Connecticut's SIP;
b) Disapprove Connecticut's SIP;
c) Conditionally approve Connecticut's SIP (can become a final approval if all federal conditions are met by a "date certain");
d) "No Action"

"No action" essentially preserves USEPA sanctions of 7/1/79 against construction or modification of major sources in non-attainment areas, where a revised SIP has yet to receive final approval. Since Connecticut is non-attainment statewide for ozone and secondary TSP, the 7/1/79 sanctions prohibit major new sources of ozone and TSP (particulates).

Based on ambient monitoring data collected through 1978, the Connecticut DEP has classified the AQCR which includes Bridgeport as an attainment area for the primary and secondary standards for SOx, NOx, and the annual primary Total Suspended Particulates (TSP) standard. The area is classified non-attainment for annual and 24-hour secondary TSP standards according to Connecticut DEP's latest monitoring data (1978) which, therefore, means that TSP offsets are required. The National Ambient Air Quality Stnadards (NAAQS) are listed in Table 5-3. Table 5-4 summarizes the state air quality data and PSD attainment classifications.

TABLE 5-2

U.S. ENVIRONMENTAL PROTECTION AGENCY
PREVENTION OF SIGNIFICANT DETERIORATION INCREMENTS

Areas designated as Class I, II, or III shall be limited to the following increases in pollutant concentration over the baseline concentration; or limited to the NAAQS if the latter would be exceeded otherwise. For any period other than an annual period, the applicable maximum allowable increases may be exceeded only once at any receptor site.

	Maximum Allowable Increase (micrograms/cubic meter)
Class I	
Particulate matter:	
Annual geometric mean	5
24-hour maximum	10
Sulfur Dioxide:	
Annual arithmetic mean	2
24-hour maximum	5
3-hour maximum	25
Class II	
Particulate matter:	
Annual geometric mean	19
24-hour maximum	37
Sulfur Dioxide:	
Annual arithmetic mean	20
24-hour maximum	91
3-hour maximum	512
Class III	
Particulate matter:	
Annual geometric mean	37
24-hour maximum	75
Sulfur Dioxide:	
Annual arithmetic mean	40
24-hour maximum	182
3-hour maximum	700

TABLE 5-3

NATIONAL AND CONNECTICUT AMBIENT AIR QUALITY STANDARDS

Pollutant	Primary Standard (ug/m3)	Secondary Standard (ug/m3)
Total Suspended Particulates:		
Annual Geometric Mean	75	60
24-hour Average[1]	260	150
Sulfur Dioxide:		
Annual Arithmetic Mean	80	60[2]
24-hour Average[1]	365	260[2]
3-hour Average[1]		1300
Nitrogen Dioxide:		
Annual Arithmetic Mean	100	

1. Not to be exceeded more than once a year.
2. Secondary standard applies only to the state of Connecticut.

TABLE 5-4

1977-78 AMBIENT AIR QUALITY DATA
AND
1977 PSD ATTAINMENT STATUS

Pollutant	Measured Data* 1977 (ug/m3)	1978 (ug/m3)	PSD Status (1977)** Primary	Secondary
TSP:				
Annual Geom. Mean	71	66	Attain.	Non-Attain.
24-Hour Average	187/184***	194/184***	Attain.	Non-Attain.
SO2:				
Annual Arith. Mean	37	46	Attain.	Attain.
24-Hour Average	197/139***	237/196***	Attain.	Attain.
NO2:				
Annual Arith. Mean	72	Not Available	Attain.	Not Applicable

* At DEP monitoring site "Bridgeport 123"

** As listed in 1977 Connecticut DEP, Air Quality Summary

*** First highest/2nd highest 24-hour averages.

5.1 Air Quality (Cont'd.)

5.1.2 Permits and Regulations (Cont'd.)

5.1.2.2 State

(a) New Source Permits

The coal gasifier system (including heat recovery boiler and gas turbine) will require a state installation and operating permit, as a "new source" of emissions to the atmosphere.

Current Connecticut emission limitations for new sources are as follows:

SO2: The maximum sulfur content of any fuel burned in Connecticut cannot exceed 0.5 percent by weight (dry basis), except in instances where a flue gas desulfurization system is installed, in which case fuel of any sulfur content may be burned as long as emissions do not exceed 0.55 pounds of SO2 per million Btu heat input.

Particulates: Total suspended particulate emissions cannot exceed 0.10 pounds per million Btu heat input. In addition, visible emissions are not to exceed 20 percent for a period of 5 minutes in any hour, and can never exceed 40 percent.

NOx: Emissions shall not exceed 0.7 pounds of NOx (calculated as NO_2) per million Btu heat input.

(b) Prevention of Significant Deterioration (PSD)

Connecticut's revised State Inplementation Plan leaves the responsibility for PSD Review with the USEPA. However, Connecticut will do a similar review when the applicant applies for state installation and operating permits, because the USEPA's review is expected to identify coal gasification at SPS as a new source which would affect Connecticut's SIP.

5.2 Solid Wastes

5.2.1 Solid Waste for Disposal

The coal gasification system would generate only ash as a solid waste.

Solid Waste and By Products Identification

Source	Waste/By Product	Quantity TPY
Pressurization, Gasification & Ash Removal	Ash	97,200
Sulfur Recovery	Sulfur	16,900

Ash from the gasification process has been tested by Westinghouse, at their Waltz Mill pilot unit in Madison, PA, and shown to produce leachate within drinking water standards. Accordingly, the ash should be acceptable for landfill.

Elemental sulfur is suitable for resale; therefore, it's a useable by-product rather than a waste. Furthermore, it can be stored in the open without environmental harm until sold or otherwise disposed of.

5.2.2 Permits and Regulations

5.2.2.1 Federal

Currently, there are no federal solid waste permits required for disposal of ash, particulates, and sulfur.

On May 19, 1980, interim Subtitle C, or hazardous waste regulations were issued. A key aspect of the interim regulations is the fact that utility "high volume" wastes, including fly ash, bottom ash, particulates, and scrubber sludge, are no longer designated "special wastes" within the hazardous waste category, since these wastes present a relatively low risk to public health, welfare and the environment.

USEPA's Office of Hazardous Waste (Washington, D.C.) is now involved in a two-year study on the nature, management practices, and effects of utility solid wastes. Final regulations for these wastes are not expected until January 1, 1983.

5.2 Solid Wastes (Cont'd.)

5.2.2 Permits and Regulations (Cont'd.)

5.2.2.1 Federal (Cont'd.)

The Toxic Substance Control Act (TSCA) significantly broadened USEPA's authority to control the production, use and disposal of any toxic substance that is distributed in commerce. A "toxic" substance, as defined in the Act, is any chemical or mixture that, because of its harmful characteristics and/or great quantities, may present an "unreasonable risk" to human health or the environment. Westinghouse tests indicate that the gasification facility will produce no by-product phenols or heavy hydrocarbons. Accordingly, TSCA regulations will not apply.

5.2.2.2 State

A Solid Waste Facility Permit is required to build, establish, or alter a landfill, or other solid waste facility in Connecticut (pursuant to Sections 19-524 (b) and 25-24i of the Connecticut General Statutes).

The Solid Waste Facility Permit may trigger an Environment Impact Statement (EIS) and public hearings for the proposed landfill, especially since Connecticut's local zoning laws and ordinances have ruled out most potential disposal sites.

The Office of Solid Waste Management Programs (Conn. DEP) provides guidelines for the disposal of fly ash, entitled "Guidelines for Fly Ash Utilization in Solid Waste Disposal Practices in Connecticut". Fly ash is treated as "mixed municipal waste" by Conn. DEP.

5.2.3 Alternative Methods of Disposal

C. E. Maquire, Inc.'s report prepared for the Connecticut DEP, "Feasibility Study - Land Disposal of Fly Ash - Norwalk Harbor Power Station," concluded that sufficient landfill space for the ash generated at the Norwalk Harbor Station does not occur within a 30-mile radius of the plant. By analogy, new disposal areas will be difficult to permit statewide. However, the following are the most probable disposal alternatives in decreasing order of probability:

- Recovery and Reuse of Ash (this may be ultimately required by RCRA); or

5.2 Solid Wastes (Cont'd)

5.2.3 Alternative Methods of Disposal (Cont'd.)

- Out-of-State Landfill Sites (as discussed in United Illuminating's "Bridgeport Harbor Coal Conversion Study"); or
- In-State/On-Site

5.3 Water Quality

5.3.1 Wastewater for Disposal

The gasification facility would generate wastewater as follows.

Source	Wastewater*	Flow (gpm)
Heat Recovery, COS Hydrolysis & Particulate Removal	Water Boiler Blowdown	9 15
Ammonia Removal	Stripped Condensate	94
Selexol	Condensate	1.2
Waste Heat Steam Generator	Boiler Blowdown	11.4
Sulfur Recovery	Boiler Blowdown Stripped Condensate	1.2 10.1
Cooling Tower System	Cooling Tower Blowdown	48
Coal Pile Drainage	To be determined	

*Constituents of Wastewater are non-toxic; and 111 GPM of purified water would be discharged from the wastewater treatment area.

5.3.2 Permits and Regulations

5.3.2.1 Federal

(a) National Pollution Discharge Elimination System (NPDES)

USEPA has delegated the NPDES permits responsibility (including the 316A and 316B permit programs) to the Conn. DEP. Under NPDES, the discharge of any pollutant from a point source to surface or sub-surface waters requires a new source permit (or a revised permit for a modified source).

5.3 Water Quality (Cont'd.)

5.3.2 Permits and Regulations (Cont'd.)

5.3.2.1 Federal (Cont'd.)

Whether SPS' coal gasification system will be classified as a new or modified source is within DEP's discretion.

(b) Thermal Discharge - Section 316A - Clean Water Act

Existing discharge to Bridgeport Harbor from once-through cooling at the Steel Point Station have permits in accorcance with Section 316A of Public Law 92-500 (Clean Water Act). A new (or modified) permit may be required for any change in heated water discharge.

5.3.2.2 State

Connecticut DEP administers the NPDES and Section 316A permit programs. Also, the state has established water quality standards for all of the state's surface waters (pursuant to Section 25-541 of the Connecticut General Statutes). The Bridgeport Harbor waters have been classified as Class SB. The Appendix presents the Class SB water regulations.

5.4 Other Environmental Considerations

5.4.1 Cooling Tower

Bridgeport Harbor is an estuary of Long Island Sound at the mouth of the Pequonnock River. However, the harbor's seawater is measurably diluted by freshwater from land drainage.

Normandeau Associates' report, "Bridgeport Harbor Ecological Studies (1971-1972) - Biological and Hydrographic Study Report", describes the circulation pattern and existing thermal regions of Bridgeport Harbor, with respect to the possible thermal effects of the Bridgeport Harbor (BHS) and Steel Point Stations (SPS).

In general, the Normandeau report found that the discharges from BHS and SPS collectively occupy the upper 6 to 10 feet of water column, and rarely interact with the bottom (except for the BHS unit No. 3 thermal plume). Hence, a continuous zone of passage for migratory and swimming organisms is available at 10 feet or more below the surfaces, at all stages of the tide.[1]