FEASIBILITY STUDY

MHD RETROFIT OF STEAM POWER PLANTS

SUMMARY AND CONCLUSIONS PART I

Prepared for
The United States Department of Energy
Division of Magnetohydrodynamics
Contract No. 01-78-ET 11058.000

JULY 1979

Gilbert/Commonwealth

ENGINEERS/CONSULTANTS Reading, PA/Jackson, MI

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MASTER

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SECTION 1.0

INTRODUCTION

The U.S. Department of Energy Division of Magnetohydrodynamics (DOE/MHD) initiated this study to evaluate the feasibility of a retrofit option to reduce the time and cost of commercializing MHD. The results are published in two parts. Part 1 includes the summary and major conclusions. Part 2 includes comprehensive technical descriptions, cost and schedule data, and related appendices.

The MHD retrofit option will integrate a nominal 260 megawatt thermal (Mwt) MHD topping cycle into an existing or scheduled private utility steam plant; this facility will test both the MHD system and the combined operation of the MHD/steam plant. The 260 Mwt input level was determined to be the size which could most effectively demonstrate and verify the engineering design and operational characteristics of a coal-fired, open-cycle, MHD power plant.

A goal of the MHD program is to have operational by the year 2003 a commercial size, fully integrated MHD plant. This would be accomplished by demonstrating commercial scale, baseload performance of a fully integrated, MHD/steam power plant. If the retrofit evaluation effort leads to a project which is successful, this commercialization goal may be accelerated.

Retrofit Goals

The retrofit project has goals similar to those of the Engineering Test Facility (ETF). The principal retrofit objective is to reduce the time and cost for demonstrating the MHD concept by increasing utility participation in the early stages of the DOE/MHD program. The following retrofit goals are identical to those of the ETF.

- o Demonstrate the engineering feasibility of the design, construction, and operation of an integrated MHD topping/steam bottoming power plant.
- o Demonstrate the technological readiness for commercialization of the MHD concept by demonstrating:
 - high plant availability and reliability,
 - the environmental advantages of MHD,
 - plant constructability,
 - operability for baseload use (at all anticipated steady-state conditions including full and part load and all other relevant modes of normal and emergency operation),
 - acceptable plant performance.
- o Produce component, subsystem, and system design data which support the high plant efficiencies projected for commercial size MHD plants.
- o Produce design data on component interactive effects, control characteristics, and performance capabilities and provide a facility for resolving critical design issues.
- o Produce economic data necessary for the evaluation of the cost of early commercial MHD power plants.

SECTION 2.0

CONCLUSIONS

As a result of these evaluations, the following conclusions were reached.

- o Retrofitting an existing steam power plant or planned design with an MHD topping cycle is technically feasible.
- o The amount of equipment that can be shared is determined largely by the economics and practicality of the chosen integration concept.
- o Direct utilization of the MHD exhaust gases to fire existing boilers is impractical technically and economically.
- o A steam connection between the topping and bottoming cycles is recommended for retrofit application.
- o MHD heat recovery is best accomplished in a new boiler design.
- o The commercialization of MHD would be enhanced with the retrofit option by involving electric utilities earlier in the MHD program.
- o An MHD retrofit project would provide savings in capital costs, compared to the stand-alone ETF by sharing equipment and a site already approved for power generation.
- o Retrofitting could improve performance of existing steam plants with capacity under 125 MWe.
- o The performance improvement with MHD retrofit would be largest in the smaller steam plants and decreases as the steam plant size increases.

- o MHD retrofit could provide swing load capacity for steam power plants larger than 150 MWe.
- o A scaled-up MHD topping cycle retrofitted to a 125 MWe plant could provide more output at a higher efficiency and a lower cost than the stand-alone ETF.

SECTION 3.0

SCOPE

Three types of power plants were investigated for MHD retrofit: 1) an existing, oil-fired, steam plant used for intermediate or peaking duty; 2) an existing, coal-fired, steam plant used for intermediate or peaking duty; and 3) a new, high efficiency, coal-fired, baseload steam plant capable of meeting the proposed 1978 Environmental Protection Agency (EPA) New Source Performance Standards.

The retrofit study involved the following actions:

- o Two retrofit steam plant integration concepts were identified: 1) MHD generated steam connection, and 2) MHD exhaust gas connection. The two concepts were evaluated, and the most feasible concept chosen. Specifically, the feasibility of using the existing boiler in the MHD heat recovery system was assessed.
- o Retrofitted plant performances were compared to each other, to the performances of the host plants, and to the performance of the stand-alone ETF.
- o A selected retrofit configuration was chosen for each of three plant sizes and types.
- o Preconceptual designs of selected retrofit configurations were prepared.
- o Retrofit schedules and costs were prepared for each of the selected configurations and compared to schedules and costs for the stand-alone ETF.

The following ground rules were established:

- o Retrofit must not interfere with independent steam bottoming plant operations.
- o Maximum use will be made of existing plant equipment.
- o The AVCO Everett Research Laboratories, Inc., ETF preferred conceptual design base^{*} with separately fired, state-of-the-art, high temperature air heaters, will be used for the reference topping cycle.
- o Montana Rosebud reference coal will be used.
- o Existing power plant design and operating data will be used.
- o Cost and schedule estimates will be developed using the DOE/MHD data bases.

Study Outline

The retrofit feasibility study outline is presented in Figure 1.

Two utilities, Montana Power Company and Southern California Edison Company, provided power plant facility design data for use in the evaluation. However, the actual use of any power plant in implementing a retrofit project would require a formal Federal competitive selection process.

^{*} AVCO Everett Research Laboratory, Inc.; Engineering Test Facility Conceptual Design, Final Report; prepared for U.S. Department of Energy, MHD Division; Report FE-2614-2 UC-90g; June 1978.

FIGURE 1
RETROFIT FEASIBILITY STUDY OUTLINE

Two concepts for integrating the MHD topping cycle to the steam bottoming plant were examined: a gas connection and a steam connection (Section 4.3).

Mechanical Technology, Inc., (MTI) studied the feasibility (Appendix B) of the gas connection and of using the bottoming plant boilers as the heat recovery system for the MHD channel exhaust gas at three conditioning levels: 1) no conditioning, 2) conditioning for slag removal and NO_x decomposition, and 3) conditioning for slag and seed removal and NO_x decomposition. This analysis considered the retrofitting of steam plants in the size range of 60 to 800 MWe.

With either the gas or steam integration concept, there are two major alternatives for using MHD generated steam: a direct steam connection path to power the turbine-generator, and an isolated loop steam connection path to power bottoming cycle auxiliaries. The operating characteristics of the selected bottoming plants and the size of the topping cycle govern the applicability of these alternative uses. In addition to powering auxiliaries, three turbine powering alternatives were analyzed:

- o Turbine fully powered with MHD generated steam
- o Turbine partially powered (turbine at turndown)
- o Turbine fully powered with MHD generated steam and supplemental existing boiler firing.

Power cycle analyses of possible retrofit combinations were conducted to determine heat balances for the combined cycles. The performance of each combined plant was evaluated in terms of efficiency and heat rate, and selected retrofit configurations were chosen for more detailed study.

Preconceptual designs for the selected retrofit configurations were prepared based on retrofit plant site layouts and equipment listings. Cost and schedule estimates were based on these designs. An overall comparison was made to the ETF conceptual design data.

SECTION 4.0

TECHNICAL SUMMARY

4.1 IDENTIFICATION OF STUDY PLANTS

Montana Power Company's Frank Bird plant in the 70 MWe class and Southern California Edison Company's Etiwanda Unit 1 in the 125 MWe class were identified as the existing bottoming plants for the study. For the new, high efficiency, baseload, bottoming plant, conceptual design data for a "reference" coal-fired plant of Gilbert/Commonwealth design in the 800 MWe class was used.

The Frank Bird plant is a 66 MWe nominal, oil/gas-fired, peaking unit located on the same site as the coal-fired, 163 MWe, E.J. Corette plant. For a retrofit, E.J. Corette's coal handling facilities can be modified to supply the MHD plant. For retrofit study purposes, the Frank Bird plant can be considered equivalent to a coal-fired unit. This plant typifies the 70 MWe class of fossil plants now in operation.

Etiwanda Unit 1, a 116 MWe nominal, oil-fired, intermediate/peaking plant, shares its site with three other oil-fired units and a gas turbine unit. Although Unit 1 has no coal handling equipment, space is available on-site to incorporate the MHD retrofit equipment and associated coal handling facilities. Etiwanda typifies the 125 MWe class of fossil plants in operation today.

The Gilbert/Commonwealth reference coal-fired plant design is typical of high efficiency, steam plants in the 800 MWe class either planned or under construction and capable of satisfying the proposed 1978 EPA New Source Performance Standards.

4.2 RETROFIT REFERENCE MHD POWER CYCLE

A retrofit reference MHD power cycle based on the AVCO/ETF MHD topping cycle was defined. The reference cycle has a computed total heat input of 260 MWt and a gross output from the MHD generator of 35.5 MWe.

In certain retrofit power cycle applications, the MHD reference cycle was scaled-up 25 percent, based on engineering and economic considerations. Extrapolating component size more than 25 percent could invalidate the existing design, test, and cost data bases of the AVCO/ETF system. The scaled-up MHD cycle, with a total input of 324 MWt, has a gas flow rate 25 percent greater than in the reference cycle, yielding a gross MHD output of 44.7 MWe.

4.3 INTEGRATION CONCEPTS

An MHD exhaust gas connection and an MHD generated steam connection, were examined for integrating the topping cycle to the bottoming plant.

With the gas connection, illustrated in Figure 2, the MHD exhaust gas passes directly to the bottoming plant boiler and generates steam for the turbine generator. Of the two concepts, this connection makes maximum use of the bottoming plant equipment. However, in these retrofit applications, the second concept is impractical for the following reasons: 1) potential interferences with conventional plant operation, 2) high risks of corroding and/or fouling existing equipment, 3) extensive equipment modifications, and 4) the high cost of these modifications.

There are no such limitations to using the steam connection; therefore, it is an acceptable retrofit integration concept. As shown in Figure 3, this connection uses the steam generated in the MHD topping cycle radiant boiler/heat and seed recovery (HRSR) system to power the bottoming plant steam turbine or auxiliaries.

FIGURE 2
INTEGRATION CONCEPT
GAS CONNECTION

FIGURE 3
INTEGRATION CONCEPT
STEAM CONNECTION

4.4 ALTERNATIVE USES OF MHD GENERATED STEAM

The alternatives for using MHD generated steam are: 1) a direct steam connection path to power the turbine (fully, partially, or fully with supplemental conventional boiler firing), and 2) an isolated loop steam connection path to power bottoming cycle auxiliaries.

The direct connection path to power the turbine generator requires that: 1) the flow and conditions of the MHD generated steam are sufficient to meet the operating requirements of the turbine either fully or partially powered, or 2) the ratio of bottoming-to-topping-cycle steam flow is practical for steam blending without extensive equipment modifications.

When the MHD radiant boiler/HRSR system supplies steam at the rated load at turbine inlet conditions, the bottoming cycle boiler can be taken out of service during combined plant operation. This is the fully powered turbine alternative.

If steam generated by the MHD radiant boiler/HRSR system is less than full load rate but within the main turbine turndown range, the combined plant can operate without conventionally firing the bottoming plant boiler. This is the partially powered turbine alternative (turbine at turndown).

When the MHD system cannot provide sufficient thermal input for producing steam for the turbine generator in the fully or partially powered condition, supplemental boiler firing can provide the additional turbine steam requirement. In this case, the bottoming plant boiler remains in service at a reduced firing rate. Steam from the topping cycle and the partially powered bottoming plant boiler blend to meet the full steam flow requirement of the turbine.

If turbine powering is impractical, MHD generated steam can be used in an isolated loop to power several bottoming plant auxiliaries, such as: boiler feed pumps, feedwater heaters, forced draft fans, induced draft fans, condensate pumps, flue gas reheat coils, and circulating pumps.

4.5 SELECTED RETROFIT CONFIGURATIONS

Combinations of MHD cycles, steam bottoming plants, and alternative uses for MHD generated steam were evaluated. Of the many combinations possible, the power cycle evaluations were limited to those which were expected to provide optimal performance. Detailed heat balances were prepared for case studies in each power plant class (70, 125, and 800 MWe). A selected retrofit configuration for each class was chosen and is presented in the following subsections.

4.5.1 Selected Retrofit Configuration - 70 MWe Class

A 70 MWe class plant, typified by the Frank Bird plant, was retrofitted with the 260 MWt MHD reference cycle. The power cycle schematic is shown in Figure 4.

The 3,600 rpm, nonreheat, tandem compound, double flow, impulse steam turbine has inlet steam conditions of 865 psia and 900°F. In conventional operation, the turbine cycle heats the feedwater in four extraction feedwater heaters.

The retrofitted power cycle uses MHD generated steam to fully power the bottoming plant turbine. The existing boiler and two high pressure feedwater heaters are not in operation. After passing through the low pressure heaters, the feedwater cools the MHD topping cycle components and enters the MHD heat recovery system to become superheated steam. Eighty-four percent of the steam generated by the MHD heat recovery boiler drives the main turbine; the remainder drives the auxiliary

FIGURE 4
SCHEMATIC OF 70 MWe
CLASS RETROFIT INTEGRATION

turbine for the MHD main compressor. The exhausts from the main and auxiliary turbines are condensed and returned to the feedwater loop. The net output from this retrofitted plant is 80.3 MWe at an overall efficiency of 30.9 percent. This retrofitted power cycle is similar to the AVCO/ETF combined cycle. The overall plant performance of each is almost identical.

Figure 5 illustrates the placement of the MHD cycle on the Frank Bird plant site. The topping cycle is arranged to minimize major piping runs and to be close to the E.J. Corette plant coal handling equipment. Compared to retrofitting an ideally suited, 70 MWe class plant, the additional costs and problems for the Frank Bird retrofit would be minimal.

4.5.2 Selected Retrofit Configuration - 125 MWe Class

The 125 MWe class plant, typified by Etiwanda Unit 1, was retrofitted with a scaled-up MHD topping cycle (324 MWt). The power cycle schematic is shown in Figure 6.

The steam turbine is a tandem compound, 3,600 rpm unit consisting of high pressure, intermediate pressure reheat, and low pressure turbine stages. The low pressure stage is triple flow. The throttle steam conditions are 1,815 psia/1,000⁰F at the high pressure stage and 1,000⁰F at the reheat stage. In conventional operation, the turbine cycle has six extraction feedwater heaters.

The retrofitted power cycle uses MHD generated steam in a direct connection to partially power the bottoming plant turbine. The existing boiler and high pressure feedwater heaters are not in operation. The feedwater passes through the low temperature economizer; it cools the MHD generator, combustor, and diffuser; and it passes through the heat recovery components of the topping cycle. The

**FIGURE 5
PLOT PLAN
RETROFIT OF FRANK BIRD PLANT
WITH MHD REFERENCE CYCLE**

compressor is electrically driven. MHD generated steam powers the main plant turbine at 80 percent design load. The net plant output is 115.0 MWe at an overall efficiency of 35.5 percent.

Figure 7 illustrates the placement of the scaled-up MHD cycle on the Etiwanda plant site. The topping cycle is arranged to minimize major piping runs. Since Unit 1 was designed for future conversion to coal firing, space reserved for coal handling and storage systems could be used for the MHD coal handling system. However, compared to retrofitting an ideally suited, 125 MWe class plant, the additional costs and problems for the Etiwanda retrofit would be significantly greater because existing plant subsystems (e.g., water storage tanks and pumps, Unit 3 cooling tower) would have to be relocated.

4.5.3 Selected Retrofit Configuration - 800 MWe Class

The 800 MWe class plant was retrofitted with the reference MHD topping cycle (260 MWt). Two isolated feedwater loops are used: one for the MHD system and the other for the main plant steam cycle. Isolating the MHD generated steam to power the plant auxiliaries has a minimal effect on the baseload plant operation. The power cycle schematic is shown in Figure 8.

The steam turbine of the reference steam plant consists of tandem compound high pressure, intermediate pressure, and four-flow low pressure stages. The steam conditions entering the high pressure stage are 2,535 psia/1,000⁰F and 1,000⁰F at the reheat intermediate stage. In conventional operation, the feedwater is heated in a string of eight extraction feedwater heaters with steam extracted from the high, intermediate, and low pressure sections of the steam turbine.

FIGURE 7
PLOT PLAN
RETROFIT OF ETIWANDA UNIT 1
WITH SCALED-UP MHD CYCLE

FIGURE 8
SCHEMATIC OF 800 MWe
CLASS RETROFIT INTEGRATION

MHD generated steam is the heat source for the bottoming plant high pressure feedwater heater. The MHD system also supplies all of the steam for its main compressor drive and nearly all of the power for the base bottoming plant boiler feed pumps. The net output for this integrated power cycle is 794.6 MWe at an overall efficiency of 33.2 percent.

Figure 9 illustrates the placement of the reference topping cycle on a typical site with the 800 MWe class plant. Since the site arrangement is flexible, no site restrictions affect retrofit. The coal storage and handling facilities of the bottoming plant could accommodate the coal requirements for the MHD system.

4.5.4 Performance Comparison

The performance of the selected retrofit configurations is compared in Table 1 to the existing oil-fired plants, coal-fired class plants, and the AVCO/ETF-based plant. A breakdown of the comparisons follows.

o 70 MWe Class Plant

The selected retrofit configuration for the 70 MWe class plant increases net plant power output by 15.2 and 18.9 MWe, respectively, over the oil-fired and coal-fired plants without MHD. Net plant efficiency is improved with retrofit by 2.0 and 4.3 percentage points, respectively. The performance of the selected retrofit configuration is almost identical to that of the AVCO/ETF-based reference plant.

The existing Frank Bird plant is more efficient and has lower auxiliary plant losses than a 70 MWe class coal-fired plant without MHD. A summary of the net plant performance follows.

**FIGURE 9
PLOT PLAN
RETROFIT OF 800 MW_e
COAL-FIRED REFERENCE PLANT
WITH MHD REFERENCE CYCLE**

	REFERENCE	70 MWe CLASS PLANT			125 MWe CLASS PLANT			800 MWe CLASS PLANT	
	AVCO/ETP BASED	FRANK BIRD			ETIWANDA UNIT 1			GILBERT/Commonwealth REFERENCE	
	STAND ALONE	RETROFIT	COAL FIRED	EXISTING OIL FIRED	RETROFIT	COAL FIRED	EXISTING OIL FIRED	RETROFIT	COAL FIRED
POWER OUTPUT									
GROSS MHD POWER, MWe	35.5	35.5	-	-	44.7	-	-	35.5	-
GROSS STEAM POWER, MWe	66.9*	67.4*	68.2	68.2	99.3	124.4	124.4	860.1*	873.0*
TOPPING LOSSES, MWe	-21.8	-21.8	-	-	-27.6	-	-	-21.8	-
BOTTOMING CYCLE LOSSES, MWe	-1.1	-0.8	-6.8	-3.1	-1.4	-11.4	-8.3	-79.2	-87.1
NET PLANT OUTPUT, MWe	79.5	80.3	61.4	65.1	115.0	113.0	116.1	794.6	785.9
STEAM CONDITIONS									
PRESSURE/MAIN STEAM TEMP./ REHEAT TEMP. (psia/F/F)	1265/950/-	865/900/-	865/900/-	865/900/-	1815/1000 /1000	1815/1000 /1000	1815/1000 /1000	2535/1000 /1000	2535/1000 /1000
CONDENSER PRESSURE, in. Hg _a	2.5	2.5	2.5	2.5	2.5	2.5	2.5	3.5	3.5
HEAT INPUT									
MHD HEAT INPUT - MWt	259.7	259.7	-	-	324.3	-	-	259.7	-
FUEL TYPE IN EXISTING BOILER	-	-	COAL	OIL	-	COAL	OIL	COAL	COAL
EXISTING BOILER INPUT, MWt	-	-	230.8	225.6	-	341.4	333.7	2133.7	2340.6
TOTAL HEAT INPUT, MWt	259.7	259.7	230.8	225.6	324.3	341.4	333.7	2393.4	2340.6
PERFORMANCE									
NET PLANT EFFICIENCY, %	30.6	30.9	26.6	28.9	35.5	33.1	34.8	33.2	33.6
NET PLANT HEAT RATE, BTU/KWH	11,146	11,035	12,816	11,811	9,622	10,311	9,807	10,279	10,163
RETROFIT METHOD									
USE OF MHD GENERATED STEAM	-	TURBINE FULLY POWERED	-	-	TURBINE PARTIALLY POWERED 25% SCALE- UP OF MHD	-	-	AUXILIARY POWER TO HIGH PRESSURE FEEDWATER HEATER AND BOILER FEED PUMPS	-

* INCLUDES POWER FOR ALL STEAM DRIVEN ACCESSORIES

TABLE 1
SELECTED MHD RETROFIT POWER CYCLE
PERFORMANCE SUMMARY

	Output (MWe)	Efficiency %
70 MWe Selected Retrofit Configuration	80.3	30.9
AVCO/ETF-Based Reference Plant	79.5	30.6
Existing Frank Bird Plant (Oil Fired)	65.1	28.9
70 MWe Class Plant (Coal Fired) Without MHD	61.4	26.6

o 125 MWe Class Plant

In the selected retrofit configuration, the gross MHD power output of 44.7 MWe offsets most of the plant power lost by turning down the turbine. MHD retrofit improves net plant efficiency by 0.6 and 2.3 percentage points, respectively, over the oil-fired and coal-fired plants. The selected configuration, with its scaled-up topping cycle (324 MWt), has a net output 35.4 MWe greater and an efficiency 4.8 percentage points greater than the AVCO/ETF-based reference plant with a 260 MWt MHD cycle. The net plant performance is summarized as follows.

	Output (MWe)	Efficiency %
125 MWe Selected Retrofit Configuration	115.0	35.5
AVCO/ETF-Based Reference Plant	79.5	30.6
Existing Etiwanda Unit 1 (Oil Fired)	116.1	34.8
125 MWe Class Plant (Coal Fired) Without MHD	113.0	33.1

o 800 MWe Class Plant

The selected retrofit configuration increases net output and does not significantly degrade plant efficiency. A slight reduction in efficiency occurs due to using relatively low energy, MHD generated steam (1,000 psia, 800°F) in a high efficiency, baseload plant. Plants in this power class can generate up to 90 MWe additional output by using MHD retrofit, if the steam turbines are designed for the increased low pressure steam flow.

The selected configuration compares in net plant performance to the reference steam plant and AVCO/ETF-based plant as follows:

	Output (MWe)	Efficiency %
800 MWe Selected Retrofit Configuration	794.6	33.2
AVCO/ETF-Based Reference Plant	79.5	30.6
800 MWe Class Plant (Coal Fired) Without MHD	785.9	33.6

4.6 COST AND SCHEDULE ASSESSMENT

Costs and schedules for the selected retrofit configurations were evaluated and compared to the stand-alone ETF.

4.6.1 Costs

Capital cost estimates were prepared for the selected retrofit configurations and compared to the stand-alone ETF costs. Figure 10 presents a summary of the estimated capital costs of stand-alone ETF reference plants and selected retrofit configurations. A cost estimate for a scaled up, stand-alone ETF of 324 Mwt is included for comparison with the 125 MWe retrofit configuration. These cost estimates are in 1978 dollars and do not include escalation or allowance for funds during construction (AFDC).

o 70 MWe Class Plant

The estimated cost to retrofit a 260 Mwt MHD cycle to a 70 MWe class coal-fired plant is \$200 million, a savings of \$33 million over the stand-alone ETF cost of \$233 million. This savings results from using the steam bottoming plant turbine equipment and coal handling facilities.

MID - 1978 DOLLARS-NO ESCALATION OR ALLOWANCE FOR FUNDS DURING CONSTRUCTION

FIGURE 10
RETROFIT CONSTRUCTION COST COMPARISON

The cost to retrofit the same topping cycle to the existing Frank Bird plant is estimated to be \$204 million. This would be only \$4 million over the cost of retrofitting the coal-fired plant, because E.J. Corette's adjacent coal handling facilities could be modified to serve the MHD topping cycle. Retrofitting the existing Frank Bird plant would, therefore, cost \$29 million less than the stand-alone ETF.

o 125 MWe Class Plant

The retrofits of the 125 MWe class coal-fired and the Etiwanda Unit 1 plants use the scaled-up MHD cycle. Retrofitting the coal-fired plant would cost an estimated \$231 million, which reflects the increased size of the MHD equipment and components. This cost is \$39 million less than the \$270 million estimate for a stand-alone ETF scaled-up to 324 Mwt.

The estimated cost to retrofit the scaled-up MHD cycle to the existing oil-fired Etiwanda Unit 1 is \$251 million. This cost exceeds that of retrofitting an equivalent 125 MWe coal-fired plant by \$20 million because of new coal handling and related MHD equipment and the relocation of the existing subsystems that interfere with the proposed MHD system layout. Retrofitting the existing oil-fired Etiwanda Unit 1 is estimated to be \$19 million less than the scaled-up, stand-alone ETF.

o 800 MWe Class Plant

The cost of retrofitting a 260 Mwt MHD cycle to a high efficiency, coal-fired, 800 MWe, baseload, steam plant is estimated at \$196 million, a savings of \$37 million compared to the ETF cost. Since the bottoming plant would be either planned or under construction, its coal handling facilities would be designed to accommodate an MHD retrofit.

There is a \$4 million savings compared to the 70 MWe class retrofit because of reduced MHD boiler rating requirements (lower steam pressure and temperature) in the isolated loop integration concept.

o Potential Savings from Fuel Costs

Retrofitting a coal-fired MHD topping cycle onto the oil-fired Frank Bird and Etiwanda Unit 1 plants would be equivalent to converting these plants to coal firing during MHD operation. In view of world oil market uncertainties and rising fuel oil prices, such conversions could provide fuel expenditure savings. The magnitude of savings would depend on variables, such as the capacity factor of the combined cycle plant in operation and the relative costs of coal and seed compared to fuel oil when the combined cycle plant is scheduled to go into operation.

4.6.2 Construction Schedules

Design and construction schedule estimates based on conventional power plant scheduling practices were prepared for the selected retrofit configurations. It was assumed that MHD development technologies will have been demonstrated and will be available for final design and manufacturing.

The construction schedule estimate for the stand-alone ETF plant is 6-1/2 years. Depending on the application, MHD retrofit could reduce this schedule by 1-1/2 years for existing plant sites because:

- o The approval of the retrofit construction permit application at an operating site should be more rapid than new site licensing. This would allow capital equipment to be procured earlier than for a stand-alone plant. The more rapid permit approval and earlier procurement are estimated to reduce the schedule one year.

- o The construction phase would be shorter, since there would be no interferences from bottoming plant heavy construction in a retrofit project.
- o Installation, checkout, and test procedures would be shortened since the existing, unaltered steam plant equipment does not require testing. Combined construction and checkout savings are estimated at 1/2 year.

If MHD retrofit is considered for a new plant at a new site, there will be no saving in schedule over an ETF because of similar licensing, construction, and checkout lead times.

FEASIBILITY STUDY

MHD RETROFIT OF STEAM POWER PLANTS

TECHNICAL DESCRIPTION PART II

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SECTION 1.0 INTRODUCTION

1.1 BACKGROUND

Alternative power generation studies have shown magnetohydrodynamic (MHD) power systems to be one of the more attractive high potential, advanced, coal-fired, electric generation alternatives for baseload utility applications. Commercial MHD topping/steam bottoming power plants are projected to:

- o Operate with coal pile-to-busbar overall plant efficiencies of approximately 50 percent.
- o Meet all existing or proposed Federal SO₂, NO_x, and particulate emission standards.
- o Generate electricity at costs competitive with other power systems.

The U.S. Department of Energy, Division of Magnetohydrodynamics (DOE/MHD), has established a three-phase development program aimed at commercialization of this power generation alternative. The first phase will develop individual MHD components and subsystems at 20 to 50 megawatt thermal (MWt) power levels. The results of this phase will become the design basis for a second phase, which will demonstrate the commercial feasibility of a fully integrated MHD topping/steam bottoming power system through the construction and operation of a 260 MWt pilot plant or the Engineering Test Facility (ETF). The third and final phase of the program will be the design, construction, and operation of a commercial demonstration MHD power plant.

DOE/MHD is investigating alternate program strategies to accelerate open-cycle MHD technology development. One option would retrofit an MHD topping cycle to either a scheduled or existing fossil fueled

utility steam power plant. To investigate the technical and economic feasibility of this retrofit option as a replacement for the stand-alone ETF was the intent of this study.

1.2 APPROACH

The main objective of the retrofit approach is to reduce the cost and accelerate the schedule for demonstrating MHD by increasing electric utility participation in the early stages of the DOE/MHD program. The goals were considered to be identical to those of the ETF.

Three types of power plants were investigated: 1) an existing, oil-fired, steam power plant used for intermediate or peaking duty; 2) an existing, coal-fired, power plant used for intermediate or peaking duty; and 3) a new, high efficiency, coal-fired, baseload, steam power plant capable of meeting the 1978 Environmental Protection Agency (EPA) New Source Performance Standards.

The study was performed in accordance with the following ground rules and criteria:

- o The MHD retrofit shall not interfere with the normal and routine operation of the existing power plant. The retrofit shall not compromise independent operation or downgrade the performance of the existing plant.
- o As much of the bottoming plant equipment as possible shall be utilized.
- o The MHD retrofit topping cycle design shall be based on the AVCO Everett Research Laboratory Engineering Test Facility (AVCO/ETF) conceptual design (Figure 1-1). Separately fired, state of the art, high temperature, air heaters (HTAH) shall be used.

FIGURE 1-1
MHD RETROFIT TOPPING CYCLE
AVCO CONCEPTUAL DESIGN SCHEMATIC

- o Existing power plant data shall be used as the basis for retrofitting.
- o Montana Rosebud coal shall be the reference fuel.

1.3 IDENTIFICATION OF STUDY PLANTS

Numerous power plants in the United States can provide host facilities for MHD retrofit. In general, any steam power plant without siting, operational, or topping-bottoming cycle integration limitations is a candidate for retrofit. Figure 1-2 summarizes the potential for retrofit in the United States.

Existing power facilities most suitable for MHD retrofit appear to be units under 200 MWe that were commissioned between 1950 and 1959. These units are normally cyclic or intermediate duty service units; Appendix A, Table A-1, lists 916 of these plants.

Appendix A, Table A-2, lists 183 steam plants, 200 MWe and larger, planned for construction. More than 50 percent of these plants must be eliminated as potential retrofit hosts because their planned completions are too early for a retrofit to be included in their designs.

Two utilities, Montana Power Company (MPC) and Southern California Edison Company (SCE), historically have expressed interest in MHD development and offered power plant facility design data for use in the retrofit evaluation. As a result of this interest, MPC's Frank Bird Plant and SCE's Etiwanda Unit 1 were used as the study plant bottoming cycles. For the large, high efficiency, baseload plant, conceptual design data for a "reference" baseload coal-fired unit of Gilbert/Commonwealth design was used. These three plants, in conjunction with the AVCO/ETF topping cycle, served as the design basis for the evaluations presented.

FIGURE 1-2
RETROFIT POTENTIAL

SECTION 2.0

STUDY PLANTS

Three steam power plants were chosen as reference bottoming plants for the evaluation of the MHD retrofit concept. These study plants are grouped below.

REFERENCE STEAM POWER PLANTS

<u>Class Plant - Nominal Power Rating - MWe</u>	<u>Fuel</u>	<u>Study Plant</u>
70 70	Oil/Gas (existing) Coal (generic)	Montana Power Company (MPC) - Frank Bird
125 125	Oil/Gas (existing) Coal (generic)	Southern California Edison (SCE) - Etiwanda Unit 1
800	Coal	Gilbert/Commonwealth - Reference Fossil Plant

The MPC and SCE plants are typical of fossil plants in operation today that could be made available for MHD retrofit. Both Frank Bird and Etiwanda were analyzed using their existing fuel and also on the basis of their being coal-fired. The reference fossil plant design is typical of new, high efficiency, coal-fired, steam plants capable of satisfying the 1978 EPA New Source Performance Standards. A brief description of the features and operating data for these facilities follows.

2.1 FRANK BIRD PLANT

The Frank Bird plant is oil/gas-fired and rated at 66 MWe. It is located on a 70 acre site at an elevation of 3,110 feet in Billings, Montana. Adjacent to the Frank Bird plant is the 163 MWe, coal-fired, E.J. Corette plant. The site is bounded on the east by the Yellowstone River, which furnishes cooling water for the once-through condensers of both plants. Figure 2-1 is a plot plan illustrating the arrangement of the power plants and supporting facilities.

NOTE:

1. FRANK BIRD PLANT IS POWER BLDG. #1 AND CORETTE PLANT IS POWER BLDG. #2.

FIGURE 2-1
PLOT PLAN
FRANK BIRD PLANT

The Frank Bird plant, constructed in 1952, was designed with provisions for converting to coal firing. Space was reserved near the boiler for incorporating coal bunkers, feeders, pulverizers, and associated transport systems. With the E.J. Corette plant on the same site, the coal storage, railroad siding, track hopper, belt conveyor, and coal stacker are nearby and could be modified for use in an MHD retrofit.

The Frank Bird plant has a steam generator delivering 865 psia/900°F superheated steam to a tandem compound, double flow, condensing steam turbine. Condensed water is passed through a steam jet air ejector condenser and a series of four feedwater heaters before reentering the boiler/ superheater. Heat for the feedwater heaters is supplied by steam extractions in the turbine, while steam for other cycle subsystems is extracted before the turbine inlet. Condensate and boiler feed pumps supply the required pressure for cycle operation.

The steam generator is a Foster Wheeler design that has blowdown and other steam losses equal to one percent of the total flow. Since this is an oil burning system, steam is extracted for oil atomization and heating. In addition, steam is extracted from the turbine to preheat air in the plenum chamber of the boiler. This steam is recovered in a Lummus main condenser while oil heating and atomization steam is lost through the exhaust stack and, therefore, replenished along with blowdown losses by the feedwater makeup.

The 3600 rpm steam turbine, supplied by General Electric (GE), has twenty impulse type stages and is rated at 60,000 kW at a throttle steam flow of 509,300 lb/hr and back pressure of 1.5 in. Hga. It has a maximum generating capability of 66,000 KW at a maximum throttle flow of 595,000 lb/hr and back pressure of 2.5 in. Hga. The turbine is designed for steam extraction at the 4th, 8th, 12th, 15th, and 17th stages. Plant requirements have not necessitated extraction at the 4th stage, and, therefore, it is blanked off. The feedwater heaters are of the closed contact design. Deaeration occurs in the condenser via the

steam jet air ejector. The plant uses a hydrogen cooled, GE, electric generator rated to produce 66,000 kWe at 60 Hz.

Figure 2-2 shows a typical heat balance for the Frank Bird steam turbine cycle operating at 2.5 in. Hga back pressure. The turbine condensate water passes through a condensate pump and steam jet air ejector condenser to pressurize and recover heat to the feedwater before heating in a series of four steam extraction heaters. These heaters are designed for terminal differences (TD) of 3.9 to 7.7°F with drains at saturated liquid conditions. The feedwater leaves the heaters 200°F below saturated conditions. The remainder of the feedwater heating takes place in the boiler. Evaporation to saturated steam and heating to 889 psia and 905°F occurs in an oil-fired boiler operating at an efficiency of 88 percent. Line losses reduce this to 865 psia/900°F at the steam turbine inlet. The steam is expanded through a turbine and returns to the condenser.

Generic Coal-Fired Plant Considerations

A generic 70 MWe class coal-fired plant would provide a more compatible retrofit than the existing oil-fired installation. The coal handling equipment, required to support an existing coal-fired boiler, could be modified and used to support the MHD topping cycle. For this ideal MHD retrofit, the major additional equipment items are a coal pulverizer, gas cleanup system, and separate exhaust stack.

Although the Frank Bird plant is oil-fired, it can be considered equivalent to a 70 MWe class coal-fired plant for retrofit purposes. The existing coal handling equipment of the adjacent E.J. Corette plant could be modified for use in retrofitting the Frank Bird facility. The turbine cycle heat balance of the coal-fired plant would be identical to that presented in Figure 2-2 for the existing installation.

FIGURE 2-2
THERMODYNAMIC CYCLE
FRANK BIRD PLANT - 66 MWe

2.2 ETIWANDA UNIT 1 PLANT

The Etiwanda station, a five unit installation, is located on a 207-acre site in San Bernardino County, about 50 miles east of Los Angeles and one mile north of the San Bernardino Freeway, at an elevation of 1,110 feet. Etiwanda Units 1 and 2 are oil/gas fired, each rated at a nominal 125 MWe; and Units 3 and 4, also oil/gas fired, are rated at 320 MWe nominal. Unit 5, the latest installation, rated at 121 MWe is powered by eight oil-fired turbines.

Etiwanda has an open design with control rooms shared by each two-unit plant. Separate administration, laboratory, warehouse, and shop buildings are provided for each unit. Also located on the site are a water storage reservoir and six fuel oil tanks with a total capacity of 1,168,000 barrels. The Colorado River aqueduct passes through the site and supplies the station circulating water, which is cooled by mechanical draft towers. Figure 2-3 is the plot plan of the Etiwanda complex illustrating the arrangement of the five units and supporting facilities.

The Unit 1 boiler was supplied and constructed by Combustion Engineering; General Electric provided the turbine/generator set. The boiler is water cooled with forced circulation, a continuous steam capacity of 920,000 lb/hr, superheater outlet conditions of 1,815 psia/1,000°F, and a reheater flow of 830,000 lb/hr with an outlet temperature of 1,000°F. Design drum pressure is 2,115 psia. The operating efficiency of this boiler is 88 percent. The boiler system includes an economizer, reheater, superheater, regenerative air heaters, forced and induced draft fans, soot blowing equipment, and facilities for burning combination oil and gaseous fuels. The boiler is designed for future conversion to coal firing.

**FIGURE 2-3
PLOT PLAN
ETIWANDA FACILITY**

The steam turbine is a reheat, triple flow exhaust, 3,600 rpm, tandem compound type, exhausting into a condenser at 2.0 in. Hga. This 32-stage turbine has been designed for steam extraction at the high pressure exit, the 11th, 14th, 16th, 18th, and 20th stages. All of the stages are impulse design. The electrical generator of the unit is hydrogen cooled and develops power at 60 Hz.

The turbine cycle of Etiwanda Unit 1 is illustrated in Figure 2-4. Steam at 1,815 psia and 1,000°F enters the high pressure turbine stage. Exhaust steam from the high pressure stage is reheated to 1,000°F and expanded in the reheat and low pressure extraction section. The triple flow, low pressure turbine discharges into a condenser. The condensate is pressurized and sent to a deaerator after passing through a steam jet air ejector condenser, a low pressure feedwater heater, and a gland steam condenser. Any dissolved and noncondensable gases in the feedwater are removed in the steam jet air ejector condenser and the deaerator. The heated water from the deaerator passes through two intermediate pressure heaters, a boiler feed pump, and two high pressure heaters. The water enters the boiler at a temperature of 447°F (about 200°F lower than the saturation condition corresponding to the boiler feed pump discharge pressure). The remaining feedwater heating, evaporation, superheating, and reheating of the steam occurs in the boiler.

The feedwater heaters are of the closed contact type using steam extraction from the turbine as a heat source. The design terminal differences for the feedwater heater outlets range from -3 to 6°F and for the drain cooler, from 8 to 10° F. (A negative terminal difference signifies that the heater is designed to remove a portion of the sensible heat of the superheated extraction steam to elevate the temperature of the feedwater.)

Generic Coal-Fired Plant Considerations

A coal-fired Etiwanda Unit 1 plant would be better suited for an MHD retrofit than the existing oil-fired unit. To make the existing plant conducive for retrofit, the additional main plant equipment required is coal unloading, storage, and handling equipment. The retrofit would also require a separate coal pulverizer, exhaust gas cleanup system, and stack. The turbine cycle heat balance of this generic plant is identical to that presented in Figure 2-4.

2.3 REFERENCE COAL-FIRED PLANT

The Gilbert/Commonwealth Reference Coal-Fired Plant provided a design base for evaluating MHD retrofit on a new, high efficiency, baseload, steam plant capable of meeting the 1978 EPA New Source Performance Standards. Sufficient site space and nearby makeup water are assumed available for retrofit purposes. Cooling is assumed accomplished by cooling towers. Figure 2-5 presents a generalized plot plan of the reference facility with two 800 MWe units.

Each unit has a gross turbine output of 859 MWe. A steam generator delivers 2,535 psia/1,000°F/1,000°F steam at a rate of 6,400,000 lb/hr to a tandem compound, four-flow turbine with a single reheat. The steam is expanded to 3.5 in. Hga in a condensing section low pressure turbine. The thermodynamic flow diagram (heat balance) for the turbine cycle appears in Figure 2-6.

Condensed turbine exhaust steam is passed through a condensate pump and a string of eight feedwater heaters before entering an economizer/boiler/superheater 150°F below saturation. The boiler system, with an efficiency of 85.7 percent, produces superheated steam at the design conditions.

FIGURE 2-5
PLOT PLAN
COAL - FIRED REFERENCE PLANT
TWO UNITS - 800 MWe EACH

II-17

To raise the feedwater temperature, the feedwater heater system of this cycle is supplied with steam extracted from the high, intermediate, and low pressure sections of the steam turbine. Design terminal differences for these feedwater heaters range from -6.5 to 3.0°F for feedwater outlets and are 8°F for all steam drains.

SECTION 3.0

MHD TOPPING CYCLES

Reference Cycle

In accordance with the ground rules of the study (Section 1.2), the AVCO/ETF MHD topping cycle was used as the basis for the reference cycle for this analysis. This reference topping cycle and a conventional steam bottoming cycle are illustrated in Figure 3-1. The MHD system has a total heat input of 260 MWt and a gross MHD generator output of 35.5 MWe. A detailed discussion and heat balance for this cycle are presented in Appendix C, Section 4.1.

Scaled-Up Reference Cycle

In some retrofit applications, an MHD cycle is scaled up 25 percent from the reference cycle. This scale-up allowed a more compatible fit with the 125 MWe steam plants (e.g., Etiwanda Unit 1) and was felt to be within the direct scaling range of the AVCO/ETF design. The scaled-up channel has a gas flow rate 25 percent greater than in the reference cycle, a total thermal input of 324 MWt, and a gross output of 44.7 MWe. The performance predictions for the scaled-up channel are compared in Table 3-1 with those from the reference channel and the results from the AVCO/ETF channel.

3.1 TOPPING CYCLE COMPONENTS

The reference MHD topping cycle consists of the following major components:

- o Main compressor
- o High temperature air heater
- o Combustor (or burner)

TABLE 3-1

COMPARISON OF AVCO/ETF TO RETROFIT REFERENCE MHD GENERATORS

	<u>AVCO/ETF*</u>	<u>RETROFIT REFERENCE (BASED UPON AVCO/ETF)</u>	<u>RETROFIT REFERENCE SCALED-UP 25 PERCENT</u>
Coal Type	Montana Rosebud	Montana Rosebud	Montana Rosebud
Preheat - °F	2500	2500	2500
Combustor + Nozzle Heat Loss - MWt	13.6	12.6	15.8
Combustor Discharge Temperature - °F	4361	4361	4363
Combustor Discharge Pressure - (atm/psia)	3.3/48.8	3.3/48.8	3.9/49.8
Combustor Discharge Flow - kg/s	65.0	65.0	65.0
Channel Length - m	9.0	9.0	9.0
Constant Channel velocity - m/s	800	800	800
Maximum Hall Field - Volts/m	2500	2500	2500
Channel Heat Loss - MWt	11.5	11.5	13.1
Channel Power - MWe	35.5	35.5	44.7
Diffuser Heat Loss - MWt	13.7	13.7	17.2
Diffuser Pressure Recovery Coefficient (Cpr)	0.46	0.46	0.46
Diffuser Discharge Temperature - °F	3445	3632	3647
Diffuser Discharge Pressure - atm/psia	0.83/12.2	0.83/12.2	0.83/12.2

*Engineering Test Facility Conceptual Design; Final Report; AVCO Everett; June 1978 FE-2614-2

- o Nozzle
- o MHD generator (or channel)
- o Magnet
- o Inverter
- o Diffuser
- o Heat recovery and seed recovery components.

The topping cycle operates as follows: Coal with slightly substoichiometric air is burned in the combustor to produce high temperature gases. A small amount of potassium seed material, in the form of potassium carbonate and potassium sulfate, is injected into the combustor to create an electrically conducting gas or plasma. This plasma is accelerated in the nozzle to a high velocity and flows through the MHD generator which is surrounded by a superconducting magnet. As the plasma passes through the magnetic field, direct current electric power is generated. This electric power is inverted and transformed for distribution. After producing electrical power, the hot gases are decelerated in the diffuser; and the gases from the diffuser exit, still at high temperature, enter a specially designed heat recovery boiler. The feedwater of a steam cycle is used to cool the walls of the various components of the MHD system. In an MHD retrofitted steam power plant, the steam generated from the MHD heat recovery boiler powers either a main turbine or auxiliaries of the bottoming cycle.

Figure 3-2 illustrates the conceptual assembly of the AVCO/ETF MHD system combustor, nozzle, MHD channel, and diffuser. The general layout of all the reference topping cycle components is shown in Figure 3-3. A brief description of the components follows.

SOURCE: AVCO, ETF DESIGN REVIEW, NOVEMBER 1978

FIGURE 3-2
CONCEPTUAL DRAWING
AVCO ETF MHD POWER LOOP

MODIFIED FROM: ENGINEERING TEST FACILITY CONCEPTUAL
DESIGN; FINAL REPORT; AVCO; JUNE 1970

FIGURE 3-3
COMPONENT ARRANGEMENT RETROFIT
REFERENCE TOPPING CYCLE

Main Compressor

A multistage axial flow compressor supplies primary air to the MHD combustor via the high temperature air heater. For the reference cycle, the compressor delivers an air flow rate of 125 lb/sec with a pressure ratio of 4.5:1. The compressor, with an assumed adiabatic efficiency of about 82 percent, has a power consumption of 11.3 MWe.

In the scaled-up cycle, the compressor provides an air delivery rate of 157 lb/sec at a pressure ratio of 4.7:1. This slightly higher pressure ratio is required by the higher operating pressure in the MHD channel. The power consumption of this larger compressor is about 14.5 MWe.

The power to the main compressor is assumed to be supplied either from an electric motor drive or from a direct steam turbine drive.

High Temperature Air Heater

The high temperature air heater (HTAH) system is designed to preheat the pressurized combustion air to about 2500°F. The system is comprised of four regenerative heaters with refractory brick matrices and is fired separately with oil. The individual heaters operate in a cyclic mode sequenced to provide a continuous supply of high temperature preheated air to the MHD combustor.

In the reference topping cycle, approximately 74 MWt is provided by the fuel oil in the separately fired heaters. This heat along with the sensible heat in the combustion air and recycled combustion make up the total thermal input to the HTAH. The retrofit evaluations are performed by assuming that eight percent (9 MWt) of the total thermal input to the HTAH is heat loss. Similarly, for the scaled-up topping cycle, the fuel oil heat rate to the HTAH and the heat loss are

92.5 MWt and 11.2 MWt, respectively. Although fuel oil will be used initially for firing, the HTAH will be designed to accept coal-derived gas as fuel in the future. Figure 3-4 shows a conceptual scheme where a typical coal gasifier fuels the HTAH system.

Combustor

The main combustor generates high temperature combustion gases by burning pulverized coal in the presence of preheated primary air. The seed material (potassium compound), injected into the combustion gases, produces a homogeneous plasma entering the MHD nozzle.

The AVCO/ETF combustor design has a downward flow, single-stage, combustion chamber in which the waterwalls are cooled with feedwater. The pulverized coal and the primary air are introduced into the combustion chamber through coaxial injectors equally spaced around the chamber. This circumferential fuel/air injector system is intended to provide a good mixing region for the combustion gases, thus ensuring a uniform temperature. The molten slag byproduct of the combustion process condenses on the combustor walls and flows to the slag port, where it is discharged for collection. A more detailed discussion can be found in the AVCO/ETF conceptual design report.

During operation, the combustor will be subjected to high electrical potential, since it is directly connected upstream of the MHD generator. Therefore, the combustor design will provide for full electrical isolation of the supports, coolant pipelines, primary air line, and slag removal connections to the combustor.

Nozzle

The nozzle connects the combustor and channel and is designed to accelerate the high temperature plasma to near sonic velocity. The

FIGURE 3-4
TYPICAL GASIFIER APPLICATION
SEPARATELY FIRED, HIGH
TEMPERATURE AIR HEATERS

expansion of gases through the nozzle is very nearly isentropic, and the high velocity gases enter the MHD channel at about 800 m/sec.

The AVCO/ETF nozzle is constructed of electrolytic copper with square cross-section and a slag wall design. The gas side of the nozzle wall is grooved to encourage formation of a slag layer which reduces the heat loss from the plasma to the wall. The nozzle walls are water cooled; however, heat loss to the nozzle cooling water is negligible when compared to the total thermal input to the combustor.

MHD Channel (Generator)

The retrofit reference MHD generator was selected to be of peg-wall faraday design operated subsonically with slag-coated, water-cooled metal walls with ceramic insulators. The working fluid, from which energy is extracted in the channel, is the combustion product of air, coal, and the seed material. A Mollier chart for this working fluid is shown in Figure 3-5.

Predicted performance estimates, flow rates and geometries for the reference and scaled-up MHD generators are presented in Figure 3-6 and 3-7, respectively. As shown, channel length is nine meters; and static exit temperatures are approximately 2230 K.

Magnet

The AVCO/ETF superconducting magnet is of saddle-coil geometry and has a maximum design field strength of six tesla. The warm bore of the magnet will accommodate the MHD channel and associated mechanical and electrical connections.

FIGURE 3-5
MOLLIER CHART FOR
RETROFIT CHANNEL PLASMA

PROPERTIES OF MHD PLASMA

5% MOIST MONTANA ROSEBUD COAL 1% POTASSIUM BY WEIGHT
1.3% MOIST AIR 95% OF STOICHIOMETRIC AIR

GENERATOR POWER OUTPUT: 35.5 MWe

NOZZLE HEAT LOSS: ~ 0 MWt
 CHANNEL HEAT LOSS: 11.5 MWt
 DIFFUSER HEAT LOSS: 13.7 MWt
 TOTAL HEAT LOSS: 25.2 MWt

FIGURE 3-6
 MHD PERFORMANCE
 RETROFIT REFERENCE

GENERATOR POWER OUTPUT: 44.7 MW_e

NOZZLE HEAT LOSS: ~0 MWt
 CHANNEL HEAT LOSS: 13.1 MWt
 DIFFUSER HEAT LOSS: 17.2 MWt
 TOTAL HEAT LOSS: 30.3 MWt

FIGURE 3-7
MHD PERFORMANCE
RETROFIT REFERENCE SCALED-UP 25%

Inverter

The AVCO/ETF direct-current-to-alternating-current inverter is of modular design and a line commutated static type with feedback regulation to match the volt-current characteristics of the MHD electrode outputs. The modular design will allow connections to be made to each of the possible channel loading configurations. A detailed write-up of the inverter and its options is presented in the AVCO/ETF report.

Diffuser

The diffuser and transmission section are designed to decelerate the high subsonic velocity gases leaving the channel to acceptable levels (approximately 50 m/sec) at the entrance to the heat and seed recovery section. The diffuser is a rectangular, two-plane divergence section with an aspect ratio of 1.0, half angles of 2-1/2 degrees and an area ratio of 4:1.

The transition section, which connects the diffuser and steam generator, is a constant area duct with a cross-section area twice that of the diffuser exit. For the reference retrofit case, the diffuser/transition section is expected to have a pressure recovery coefficient of 0.46.

Heat Recovery and Seed Recovery Components

- o Heat Recovery Boiler - The hot gases from the diffuser exit enter the heat recovery boiler (steam generator) with sufficient temperature and thermal energy to generate steam and to provide the preheat requirements for the recycled gas, secondary air, and combustion air of the separately fired HTAH system. The major components of the AVCO/ETF heat recovery system, illustrated in Figure 3-8, are: the primary radiant slag furnace, seed recovery furnace (or the secondary radiant furnace), air heater furnace, and economizers.

SOURCE: ENGINEERING TEST FACILITY
CONCEPTUAL DESIGN; FINAL
REPORT; AVCO; JUNE 1978

FIGURE 3-8
AVCO/ETF HEAT
RECOVERY SYSTEM

Flue gases exit from the diffuser at about 3,600°F and enter the water-cooled primary radiant slag furnace. About five percent of the total slag is extracted in this furnace. Heat is transferred to the water-cooled walls at a rate of about 22,500 Btu/hr/ft². The gas, at this point, is substoichiometric (reducing conditions) and cools at about 340°F/sec, which prevents NO_x from "freezing" at unacceptably high levels. Leaving the primary radiant section, the flue gases enter the water-cooled secondary radiant furnace at 2,890°F. This furnace is also called the seed recovery furnace, since seed material that condenses on the furnace water-cooled walls is recovered. Pendant type, secondary superheater sections are also located in this furnace. The estimated heat transfer rates to the water-cooled walls and superheaters are 15,500 and 22,500 Btu/hr/ft², respectively. The flue gas exists from this furnace section at about 1,880°F.

Secondary air is injected into the hot gases downstream of the secondary radiant furnace to complete the combustion of the MHD exhaust gases. Combustion of carbon monoxide and other species not fully oxidized in the main MHD combustor heats the gas to approximately 2,000°F. This reheated gas enters the air heater furnace (convective section) which also has water-cooled walls. In this furnace section, primary superheating of steam is achieved in a pendant type, cross flow superheater. Recycled gas, secondary air, and combustion air to the HTAH system are also preheated in this section. The estimated heat transfer rates are 7,000 Btu/hr/ft² to the water-cooled walls and 20,300 Btu/hr/ft² to the superheaters. The remaining flue gases heat the feedwater in the economizer sections; the estimated heat transfer rate is 3,500 Btu/hr/ft². After passing through the economizer sections, the flue gases enter the gas cleanup system for final seed recovery and particulate removal.

- o Seed Reprocessing System - The AVCO/ETF MHD system is designed to recover and reprocess the seed material injected into the combustor. A portion of the potassium sulfate recovered in the downstream boiler components will be regenerated to sulfur-free potassium salts for reinjection into the combustor. In this manner, sulfur removal from the exhaust gases is continuous; and, by suitably adjusting the ratio of regenerated seed to potassium sulfate, the EPA sulfur emission limits will not be exceeded.

The Formate Process is recommended for seed reprocessing; details of this process are presented in the AVCO/ETF conceptual design report.

SECTION 4.0

INTEGRATION CONCEPTS

An MHD exhaust gas connection and an MHD generated steam connection were examined for integrating the topping cycle to an existing or planned steam bottoming plant. With either integration concept, the combined cycle operation allows the energy of the plasma to generate power in the topping cycle, while the energy in the lower temperature MHD exhaust gas is converted into additional power in the steam cycle.

Figure 4-1 illustrates the gas path connection concept where MHD exhaust gas is used to fire the conventional boiler. This concept attempts to utilize the bottoming plant boiler as the heat recovery system for the topping cycle gas stream. This method was found to be technically and economically impractical for MHD retrofit (Section 4.2). The steam connection, illustrated in Figure 4-2, was found to be a more acceptable integration concept for retrofit, although there is less equipment sharing than in a gas connection.

4.1 STEAM CONNECTION

In the steam connection, feedwater is used to recover the waste heat generated by MHD topping cycle components. This steam is used in the bottoming cycle, and the detail of its integration depend on the relative size of the steam plant and the MHD topping cycle. Two alternative uses of this steam, main turbine powering and auxiliary powering, are discussed below.

Main Turbine Powering

Main turbine powering requires a direct steam connection between the topping and bottoming cycles, with the feedwater and steam shared between them. There are three alternatives for turbine powering; the one to use depends upon the size of the topping and bottoming cycles. These alternatives are:

FIGURE 4-1
GAS PATH CONNECTION

FIGURE 4-2
STEAM CONNECTION

(1) fully powered turbine, (2) partially powered turbine (turbine at turndown), and (3) fully powered turbine with supplemental conventional boiler firing.

- o Turbine Fully Powered with MHD Generated Steam - The MHD heat recovery system provides full steam requirements for the turbine to operate at design point. The existing boiler is taken out of service during MHD operation. The 70 MWe class turbine could be retrofitted in this manner.
- o Partially Powered Turbine - The existing turbine could be operated in a turndown condition if the MHD topping cycle cannot provide full steam requirements. As a result, the turbine would be at less than design point efficiency. The 125 MWe class turbine can operate at 65 percent of design point when retrofitted with the reference MHD cycle or at 80 percent of design when retrofitted with a scaled-up MHD cycle.
- o Turbine Fully Powered with Supplemental Boiler Firing - When the topping cycle heat recovery system can supply only a small portion of the turbine throttle steam requirements, the existing boiler can remain in service at reduced firing. By blending the MHD generated steam with the partially-fired boiler steam, the full requirement of the turbine can be satisfied. The 125 MWe class turbine can also be retrofitted in this manner.

Auxiliary Powering

Another method of steam connection isolates the MHD feedwater loop from the main plant feedwater system, and the MHD generated steam powers the bottoming plant auxiliaries. For large baseload plants (larger than 400 MWe), this type of integration is a workable alternative. For the 800 MWe class plant, the reference MHD cycle would power the plant auxiliaries with an isolated loop steam connection.

Discussion

As the size of the steam plant increases with respect to the MHD generator, the preferred use of MHD generated steam changes. The preferred method of integrating the topping cycle depends on the

specific steam plant design and must be considered case by case. If the topping and bottoming cycles are matched, MHD generated steam can fully power the turbine. In general, as the steam plant size increases, partially powering a turbine with MHD generated steam is effective for steam plants as large as 180 MWe. For steam plants between 120 and 400 MWe, the most effective use of MHD steam is to fully power the existing turbine with supplemental boiler firing. Depending on the actual plant, this supplemental firing may require design and operating modifications to the existing boiler. For steam plants larger than 400 MWe, powering auxiliaries with an isolated loop appears attractive, since there would be minimal interference with baseload plant operation. Figure 4-3 illustrates the approximate range for which each of these uses of MHD generated steam is considered practical for the reference MHD cycles in retrofit applications.

4.2 GAS CONNECTION

A comprehensive study was conducted by Mechanical Technology Incorporated (MTI) to determine the feasibility of the gas connection between the MHD channel exhaust gas and the existing boiler. A summary discussion of the major findings follows; the complete report is presented in Appendix B. MTI concluded that a gas connection between the MHD diffuser exhaust and the existing boiler equipment would be impractical due to the: 1) potential interference with conventional plant operation, 2) high risk of corroding/fouling existing equipment, 3) extensive equipment modifications required, and 4) estimated cost of these modifications.

Existing steam plants in the 60 to 800 MWe range were analyzed for retrofit potential. Gas connections were evaluated at three different MHD diffuser exit gas conditioning levels: 1) no conditioning, 2) conditioning for slag removal and NO_x decomposition, and 3) conditioning for slag and seed removal and NO_x decomposition. The ground rules and criteria for this analysis are identical to those discussed in Section 1.2 for the overall retrofit study.

There are several significant differences between the exhaust gases of the MHD topping cycle and the conventional coal-fired system. These differences make it impractical to directly use MHD exhaust gases in a conventionally designed boiler. In the MHD system, the exiting gas temperature is approximately 3,600°F, whereas the maximum firing temperature of a coal-fired boiler is approximately 3,200°F. Large quantities of potentially corrosive potassium compounds from the seed materials are contained in the MHD gas while most flue gases contain only trace quantities of potassium. The particulate loading in the MHD system is substantially higher than a typical coal-fired boiler, and, therefore, boiler designs and material requirements for the MHD system differ significantly from the conventional design.

Design features of a nonreheat, 60 MWe coal-fired boiler are shown in Figure 4-4. For comparison, an MHD heat recovery system based on the AVCO/ETF design is presented in Figure 4-5. Several chambers (or passes) in the MHD boiler system decompose NO_x and selectively precipitate coal slag and potassium seed. The volume of the MHD boiler is much greater than that of a coal-fired boiler. The larger volumes provide:

- o A lower gas velocity to allow slow cooling rates down to 3,000°F for NO_x decomposition
- o Wider convective pass tube spacing to prevent plugging caused by the increased particulate loading
- o Increased heat transfer surface area required to offset anticipated surface fouling.

A comparison of convective pass tube spacing for the ETF designs, conventional coal-fired boilers, and black liquor recovery boilers is presented in Figure 4-6. (Black liquor recovery boilers have been included in this comparison because they have gas side particulate loadings and plugging tendencies similar to that anticipated for the

SUPERHEATER (S/H) GAS INLET TEMPERATURE ~ 2100°F
 RADIANT SECTION RESIDENCE TIME ~ 2 SEC
 SUPERHEATER LATERAL SPACING ~ 1 FT

FIGURE 4-4
 TYPICAL NON-REHEAT
 60 MWe COAL - FIRED BOILER

FIGURE 4-5
TYPICAL MHD HEAT AND SEED
RECOVERY SYSTEM
(AVCO/ETF BASE)

FIGURE 4-6
CONVECTIVE PASS
TUBE SPACING COMPARISON.

MHD system.) Convective pass superheater tube spacing for a conventional coal-fired plant is approximately one foot, whereas that recommended for the MHD system is four to five feet.

For all levels of conditioning evaluated, major boiler modifications are required. These include: 1) lateral respacing of convective passes, 2) addition of increased heat transfer surface, 3) construction of additional boiler passes, 4) major waterwall modification for the MHD gas entrance, 5) tube material changes, and 6) circulation system modifications. While these modifications could provide an acceptable boiler configuration for use with the MHD system, this approach is considered impractical since: 1) modifying the existing boiler would yield no significant cost advantage over a specifically designed unit, and 2) there can be no guarantee that the modified boiler would not significantly interfere with conventional plant operation.

SECTION 5.0 RETROFIT CONFIGURATIONS

Alternative power cycle integration schemes were evaluated to determine the optimum MHD retrofit configuration for each class of steam bottoming plant ranging in size from 70 to 800 MWe.

Detailed heat balances were prepared to assess the overall performance of the combined cycles. Appendix C presents further details of the 23 alternative retrofit configurations considered for analysis. Several of these were evaluated in each plant class by comparing the performance of the base plants and ETF reference plant. This section describes the selected configuration for each class and summarizes its performance.

5.1 BASIS FOR SELECTION

The configuration for each class was selected on the basis of its feasibility and thermodynamic performance. In addition to the ground rules discussed in Section 1.2, the following general criteria were used to guide the selection:

- o The configurations shall be capable of recovering the maximum amount of energy from the topping cycle exhaust gas.
- o The MHD topping components shall be designed and integrated into the base plant without penalizing normal plant performance or its operation when the MHD is out of service.

5.2 70 MWe CLASS PLANT

The reference MHD topping cycle with a thermal rating of 260 MWt was retrofitted to the 70 MWe class plant. In the evaluation of alternate retrofit schemes, three configurations were considered.

- o The topping cycle was integrated to the base plant with the compressor of the topping cycle driven by an electric motor. To keep the turbine output at approximately 70 MWe, the economizer of the topping cycle had to be derated, but all the heat from cooling the MHD components was recovered.
- o All the feedwater heaters of the base plant remained in operation. The temperature and pressure of the feedwater entering the MHD system was sufficiently high that the heat from cooling the MHD generator had to be rejected to a separate cooling loop.
- o The high pressure feedwater heaters were removed during MHD operation and this heating capacity was replaced with heat being rejected in cooling the MHD topping cycle components. This scheme was preferred and developed further.

5.2.1 Description

The Frank Bird steam turbine cycle was utilized as the typical bottoming cycle for the 70 MWe class plants. The turbine is a tandem compound, 3,600 rpm unit of single, nonreheat, high pressure, impulse design. It exhausts into a condenser designed to operate at 2.5 in. Hga. With inlet conditions of 865 psia and 900⁰F, the turbine has a capacity of 66 MWe. Steam from oil or gas firing of the existing boiler powers this system, which includes four extraction feedwater heaters.

The 70 MWe class steam cycle, integrated with the reference MHD topping cycle, is shown in Figure 5-1. The feedwater from the low pressure heater enters the MHD heat recovery boiler and returns as superheated steam at turbine throttle conditions. The existing boiler is not required to operate. Most of the total main steam generated from the MHD cycle drives the plant turbine, while a small portion (16 percent) powers an auxiliary turbine to drive the main air compressor. The exhaust from the main and auxiliary turbines condenses and return to the feedwater loop.

FIGURE 5-1
SCHEMATIC OF 70 MWe
CLASS RETROFIT INTEGRATION

In the feedwater heater string, only two low pressure feedwater heaters operate at 9.5 and 26.5 psia. The two high pressure heaters are turned off to keep the feedwater at a lower temperature (239°F) for maximum recovery of waste heat from the MHD system. If the high pressure heaters also operated, the feedwater would exit at relatively high temperature (350°F) and cause a derating of the economizer. Figure 5-2 shows the heat balance details for this integration scheme.

Referring to Figure 5-2, feedwater from the booster pump enters the low temperature split economizer at 239°F and leaves at 266°F to cool the MHD generator while remaining below saturation conditions. It then is pressurized by the boiler feed pump and enters the high temperature split economizer before cooling the combustor and diffuser. The available heat in the exhaust gas stream of the heat recovery boiler produces superheated steam at 865 psia, 900°F. Most (84 percent) of the steam drives the main plant turbine to produce a gross electrical output of 56 MWe. If all of the main steam is used to drive the main turbine, the gross output would exceed its capacity of 66 MWe. Thus, an auxiliary turbine drive was selected to drive the main compressor.

The basic performance of the 70 MWe class plant is:

- o Turbine gross electrical output - 56.1 MWe
- o Net plant output - 80.3 MWe
- o Overall plant efficiency - 30.9 percent.

5.3 125 MWe CLASS PLANT

Three integration schemes were evaluated for the 125 MWe class plant. Each scheme, with several variations in configuration, is described in detail in Appendix C. The first scheme integrates the turbine cycle with the 260 MWt reference topping cycle without firing the existing boiler.

The second uses the reference topping cycle with steam blending and partial firing of the existing boiler to operate the turbine at full load. The third uses the scaled-up (324 MWt) topping cycle without firing the existing boiler. The topping cycle in the selected configuration supplies steam to produce approximately 80 percent of the turbine design load requirements.

5.3.1 Description

The bottoming cycle considered representative of the 125 MWe class plant is Etiwanda Unit 1. Its steam turbine is a tandem compound, 3,600 rpm unit, consisting of high pressure, reheat, and low pressure turbine stages. The triple flow, low pressure turbine exhausts into a condenser at 2.5 in. Hga, and the throttle conditions are 1,815 psia at 1,000°F. Steam to the reheat turbine is 1,000°F. The turbine generator has a rated capacity of 125 MWe. The unit is normally supplied from oil-fired boilers.

The integrated cycle of the 125 MWe class plant is shown schematically in Figure 5-3. In this scheme, neither the existing boiler nor the high pressure feedwater heaters above the deaerator are operated.

Referring to Figure 5-4, the heat balance diagram, the feedwater from the deaerator, at 200 psia and 212°F, enters the low temperature split economizer and then passes through the MHD generator before it is pressurized to 2205 psia by the boiler feed pump. It enters the high temperature economizer at 324°F and is then circulated through the combustor and diffuser walls as a coolant. The diffuser coolant water then passes through the remaining components of the MHD heat recovery boiler.

Superheated main steam goes to the high pressure turbine throttle at 1,815 psia and 1,000°F. It then is reheated to 1,000°F, passes through

FIGURE 5-3
SCHEMATIC OF 125 MWe
CLASS RETROFIT INTEGRATION

FIGURE 5-4
HEAT BALANCE OF 125 MW_e
CLASS RETROFIT INTEGRATION

to the intermediate pressure reheat turbine and is exhausted into a low pressure turbine for further expansion. Condensate from the condenser, along with the cascaded drains from the low pressure extraction heaters, returns to the feedwater circuit.

Since the high pressure feedwater heaters are not considered in-service in this scheme, additional steam is available to expand through the turbine to produce additional electrical power. These heaters were eliminated to maintain a lower feedwater temperature at the economizer entrance and to ensure full heating capacity in the economizing section. Since the feedwater from the low temperature economizer is lower in temperature and pressure, the waste heat from cooling the MHD generator can be recovered. If the full heater system is operated, the feedwater would exit the last heater at 450°F and 2,200 psia and, with MHD waste heat rejected in a separate loop, the stack gases leaving the economizer would approach 500°F. The result would be inefficient operation of the boiler.

The performance of the 125 MWe class plant is:

- o Turbine gross electrical output - 99.3 MWe
- o Net plant output - 115.0 MWe
- o Overall plant efficiency - 35.5 percent.

5.4 800 MWe CLASS PLANT

Three configurations were considered for the 800 MWe class plant. In the first, a separate feedwater loop for the MHD system is used to generate superheated steam which is used to provide heat to a special feedwater heater and to drive the main MHD compressor and a part of the main boiler feed pump. In the second, the bottoming plant auxiliaries are fully or partially powered by MHD steam. In the third, the MHD steam is directly connected to the main turbine inlet and blended with

steam from the partially fired main boiler. The first of these configurations was selected as the preferred arrangement.

5.4.1 Description

As shown schematically in Figure 5-5, the 260 Mwt topping cycle was integrated with an 800 MWe, subcritical ($2,535 \text{ psia}/1,000^{\circ}\text{F}/1,000^{\circ}\text{F}$), coal-fired, baseload plant of Gilbert/Commonwealth design. For this case, the MHD system and the bottoming plant are essentially independent, with the steam produced by the MHD boiler supplying a special feedwater heater and the main MHD compressor turbine.

Referring to Figure 5-6, the heat balance diagram, the feedwater of the topping cycle cools the MHD components and recovers as much of the waste heat as possible from the MHD heat recovery boiler. The MHD feedwater system is self-contained, with its own condenser designed for operation at 3.5 in. Hga and a deaerator operating at 115 psia. Condensate is pumped from the condenser to the MHD system to produce two levels of steam sources, one at 1,150 psia and 800°F , the other at 1,050 psia and $1,000^{\circ}\text{F}$. The steam at 800°F is used as a heat source for the special feedwater heater at the main plant. The steam at $1,050^{\circ}\text{F}$ is used to drive the MHD compressor turbine, which exhausts into the 115 psia steam header. This header supplies most of the steam to the main plant boiler feed pump and deaerates the MHD system feedwater.

The 800 MWe class plant includes a tandem compound, four-flow, reheat turbine. The boiler feedwater is heated by a system of seven extraction feedwater heaters and an eighth special heater installed for MHD retrofit purposes. Ninety percent of the power to the boiler feed pumps is supplied by the MHD cycle, while the remainder is provided through extraction from the main plant turbine.

FIGURE 5-5
SCHEMATIC OF 800 MWe
CLASS RETROFIT INTEGRATION

The thermodynamic state points shown in the heat balance diagram correspond to full load operation of both the MHD system and the main plant. At full load, the MHD system supplies power to the MHD compressor and the main plant boiler feed pump. It also provides some thermal energy to the main plant feedwater via the special heater.

When operated at full load, five percent over pressure, and valves wide open, the low pressure turbine will be back-end loaded at 95 percent. With no requirement for extraction steam for feedwater heating, the turbine flow following the extraction point would increase. Since the flow through the back end is maintained constant, the flow rate is reduced to keep the loading at the design value. If the throttle steam flow in the retrofit cycle is maintained at the same level as in the base plant, more flow to the turbine is available but is restricted by the back-end loading. The turbine flow rate is therefore decreased, which in turn reduces the fuel input to the boiler.

The performance of the 800 MWe class plant is:

- o Turbine gross electrical output - 827.9 MWe
- o Net plant output - 794.6 MWe
- o Overall plant efficiency - 33.2 percent.

The main plant turbine could also be designed to achieve full steam flow with the MHD system in service (Appendix C - Case 3E). With the turbine so designed, the stress loading with the eighth feedwater out of service would be acceptable. When the MHD system is out of service and the eighth feedwater heater is extracting steam, the back-end of the turbine will pass less than full flow and remain within design limits (Appendix C - Case 3F). With this arrangement, the power output with MHD out-of-service would be 700.6 MWe with a net efficiency of 33.6 percent. Operating the MHD system increases the net output to 796 MWe with an overall efficiency of 33.5 percent. Thus, with MHD on-line,

the plant output can be increased by about 95 MWe using the same steam flow rate without a significant loss in efficiency.

Figure 5- 7 shows the impact on the plant heat rate for part load operation. The bottom curve is the variation of the net plant output with the MHD system not functioning. The net plant efficiency drops from 33.6 percent at 700.6 MWe to 31.9 percent when the output is reduced to a part load value of 437.9 MWe.

5.5 PERFORMANCE COMPARISON

Table 5-1 compares the performance of the various retrofit configurations to the AVCO-based stand-alone ETF. The features of this comparison are as follows:

o 70 MWe Class Plant

Retrofit for the 70 MWe class plant increases net plant power output by 15.2 and 18.9 MWe, respectively, over the oil-fired and coal-fired plants without MHD. Net plant efficiency is improved with retrofit by 2.0 and 4.3 percentage points, respectively. The performance of the selected retrofit configuration is almost identical to that of the AVCO/ETF-based reference plant.

The existing Frank Bird plant is more efficient and has lower auxiliary plant losses than a 70 MWe class coal-fired plant without MHD.

o 125 MWe Class Plant

In the retrofit configuration, the gross MHD power output of 44.7 MWe offsets most of the plant power lost by turning down the turbine. MHD retrofit improves net plant efficiency by 0.7 and 2.4 percentage points, respectively, over the oil-fired and coal-fired

FIGURE 5-7
PART LOAD HEAT RATE
FOR LARGE POWER PLANTS

	REFERENCE	70 MWe CLASS PLANT			125 MWe CLASS PLANT			800 MWe CLASS PLANT	
	AVCO/ETF BASED	FRANK BIRD			ETIWANDA UNIT 1			GILBERT/COMMONWEALTH REFERENCE	
	STAND ALONE	RETROFIT	COAL FIRED	EXISTING OIL FIRED	RETROFIT	COAL FIRED	EXISTING OIL FIRED	RETROFIT	COAL FIRED
POWER OUTPUT									
GROSS MHD POWER, MWe	35.5	35.5	-	-	44.7	-	-	35.5	-
GROSS STEAM POWER, MWe	66.9*	67.4*	68.2	68.2	99.3	124.4	124.4	860.1*	873.0*
TOPPING LOSSES, MWe	-21.8	-21.8	-	-	-27.6	-	-	-21.8	-
BOTTOMING CYCLE LOSSES, MWe	-1.1	-0.8	-6.8	-3.1	-1.4	-11.4	-8.3	-79.2	-87.1
NET PLANT OUTPUT, MWe	79.5	80.3	61.4	65.1	115.0	113.0	116.1	794.6	785.9
STEAM CONDITIONS									
PRESSURE/MAIN STEAM TEMP./ REHEAT TEMP. (psia/°F/°F)	1265/950/-	865/900/-	865/900/-	865/900/-	1815/1000 /1000	1815/1000 /1000	1815/1000 /1000	2535/1000 /1000	2535/1000 /1000
CONDENSER PRESSURE, in. Hg _a	2.5	2.5	2.5	2.5	2.5	2.5	2.5	3.5	3.5
HEAT INPUT									
MHD HEAT INPUT - MWt	259.7	259.7	-	-	324.3	-	-	259.7	-
FUEL TYPE IN EXISTING BOILER	-	-	COAL	OIL	-	COAL	OIL	COAL	COAL
EXISTING BOILER INPUT, MWt	-	-	230.8	225.6	-	341.4	333.7	2133.7	2340.6
TOTAL HEAT INPUT, MWt	259.7	259.7	230.8	225.6	324.3	341.4	333.7	2393.4	2340.6
PERFORMANCE									
NET PLANT EFFICIENCY, %	30.6	30.9	26.6	28.9	35.5	33.1	34.8	33.2	33.6
NET PLANT HEAT RATE, BTU/KWH	11,146	11,035	12,816	11,811	9,622	10,311	9,807	10,279	10,163
RETROFIT METHOD									
USE OF MHD GENERATED STEAM	-	TURBINE FULLY POWERED	-	-	TURBINE PARTIALLY POWERED 25% SCALE- UP OF MHD	-	-	AUXILIARY POWER TO HIGH PRESSURE FEEDWATER HEATER AND BOILER FEED PUMPS	-

* INCLUDES POWER FOR ALL STEAM DRIVEN ACCESSORIES

TABLE 5-1
SELECTED MHD RETROFIT POWER CYCLE
PERFORMANCE SUMMARY

plants. The scaled-up topping cycle has a net output 35.4 MWe and an efficiency 4.9 percentage points greater than the AVCO-based stand-alone ETF with a 260 MWt MHD cycle.

o 800 MWe Class Plant

Retrofit increases net output without a significant reduction in plant efficiency. Plants in this power class can generate up to 90 MWe additional output by using MHD retrofit with steam turbines designed for increased low pressure steam flow.

SECTION 6.0

RETROFIT PLANT COST AND SCHEDULES

For each retrofit configuration, equipment lists and plot plans were prepared to provide a basis for developing comparative cost and schedule estimates. These estimates are compared to those of the stand-alone ETF.

6.1 RETROFIT PLANT EQUIPMENT

The subsystems equipment and balance of plant equipment for retrofit operation are a combination of those employed in the MHD cycle and in the conventional steam cycle. A list of major equipment and operational characteristics for the retrofit configurations are presented in Appendix D. Controls to monitor and regulate the retrofit plant operation, similar to those employed in conventional plant operation, will have to be incorporated in the MHD loop. Complete mechanical isolation of the topping cycle will be needed when the steam plant operates independently.

6.2 CONCEPTUAL SITE DEVELOPMENT

Retrofitting MHD to existing plants, or plants planned for construction, may involve design compromises or added cost to accommodate interferences imposed by existing site conditions. The site layout for an MHD retrofit installation may require special equipment arrangements to maintain existing plant equipment locations. Conversely, existing plant equipment may have to be relocated to allow for the practical placement of MHD components. These types of site restrictions may make the equipment layouts less than optimum; the effects could range from negligible to prohibitive depending on how practical it is to overcome the interferences encountered on an actual site.

The most difficult or costly plant sites for retrofit are those with existing oil- or gas-fired boilers. These sites normally have no provision for operation with coal and may not have the space required for expanding to coal-fired MHD operations. The retrofit will require an area to deliver, unload, store, process, and handle coal, waste products, and cleanup equipment. Providing facilities for coal firing, on a site where oil or gas are burned, could add as much as five percent to the cost. Such items as increased length of piping and electrical runs would also increase costs, but to a lesser degree than the coal handling equipment.

6.2.1 Site Layouts

Site layout drawings were prepared to illustrate how each retrofit configuration would be arranged on typical plant sites. Figure 6-1 shows the retrofit of the Frank Bird plant with the 260 Mwt reference topping cycle. The MHD equipment is located to minimize major piping runs and to be in close proximity to the existing coal handling equipment of the E.J. Corette plant. Equipment interferences resulted in steam piping runs of approximately 350 feet, which is 100 feet more than would be considered typical. Items which would require relocation include: electrical transmission lines, municipal water lines, office buildings, portions of the coal conveyor, and the open cooling-water discharge canal (to be replaced by a submerged tunnel) for the E.J. Corette plant.

Figure 6-2 shows the retrofit of the Etiwanda Unit 1 facility with a 324 Mwt scaled-up topping cycle. Since this plant was originally designed for future conversion to coal firing, space reserved for these facilities can be used for the retrofit application. Items requiring relocation include: the cooling tower for Unit 3, water storage tanks, waste water sumps, shops, a warehouse, the water treating building, and the hydrogen storage area.

**FIGURE 6-1
 PLOT PLAN
 RETROFIT OF FRANK BIRD PLANT
 WITH MHD REFERENCE CYCLE**

FIGURE 6-2
PLOT PLAN
RETROFIT OF ETIWANDA UNIT 1
WITH SCALED-UP MHD CYCLE

Figure 6-3 is a plot plan showing the assumed placement of the reference 260 Mwt topping cycle equipment with an 800 MWe coal-fired steam power plant. Since the plant is a reference design, the site is assumed to be without physical restrictions or interferences. The coal storage and handling facilities of the bottoming plant can accommodate the coal requirements for the MHD system.

6.3 CAPITAL COST ESTIMATES

As shown in Appendix E, conceptual construction cost estimates were prepared for the "stand alone" ETF reference plants and each of the retrofit plants. These estimates are arranged in accordance with a modified Federal Power Commission (FPC) Code of Accounts as shown in Table E-1 of Appendix E. Minor modifications to the AVCO cost base were made to conform with the Gilbert/Commonwealth cost models and to provide better correlation with other system cost estimates. A summary of these estimates is presented in Table 6-1.

6.3.1 Bases

The estimates include design, procurement, fabrication, construction, installation, and checkout. The retrofit plant costs include the MHD topping subsystems and interface items such as adaptors, isolation valves, and bypass piping not specifically included in the design of the stand-alone ETF. Quantities, design conditions, sizes, etc., were obtained from heat balances, flow diagrams, conceptual layouts, and equipment lists (Appendix D). Other costs were obtained from historical information. The estimates were developed in accordance with the following guidelines and assumptions.

- a. The cost of equipment, materials, and labor are based on mid-1978 costs. Average U.S. historical cost indexes published by the Engineering News Record and in-house data files were used.

FIGURE 6-3
PLOT PLAN
RETROFIT OF 800 MWe
COAL-FIRED REFERENCE PLANT
WITH MHD REFERENCE CYCLE

* EXISTING FRANK BIRD PLANT ** EXISTING ETIWANDA - UNIT 1 † MID-1978 DOLLARS, NO ESCALATION, OR AFDC		CONFIGURATION	STAND ALONE	RETROFIT		RETROFIT	STAND ALONE	RETROFIT	
		PLANT	ETF	70 MWE CLASS		800 MWE CLASS	SCALED ETF	125 MWE CLASS	
		MHD SIZE - MWT	260	260	260	260	324	324	324
		FUEL	COAL	COAL	OIL *	COAL	COAL	COAL	OIL **
ACCOUNT NUMBER	ACCOUNT DESCRIPTION	ESTIMATED CONSTRUCTION COSTS - \$10 ⁶ (†)							
311	STRUCTURES AND IMPROVEMENTS	22.6	16.7	17.2	16.3	25.2	18.9	24.2	
312	BOILER PLANT EQUIPMENT	52.7	47.4	50.2	45.8	65.4	58.9	70.6	
314	TURBOGENERATOR UNIT EQUIPMENT	17.0	1.8	1.8	1.8	19.5	1.9	1.9	
315	ACCESSORY ELECTRIC EQUIPMENT	19.7	18.7	19.4	17.8	20.7	19.7	19.7	
316	MISCELLANEOUS POWER PLANT EQUIPMENT	1.5	0.6	0.6	0.6	1.6	0.6	0.6	
317	MHD TOPPING CYCLE	91.3	91.3	91.3	91.3	107.6	106.6	106.6	
350	TRANSMISSION PLANT	2.8	2.5	2.5	2.5	3.2	2.9	2.9	
	SUBTOTAL DIRECT ACCOUNTS	\$207.6	\$179.0	\$183.0	\$176.1	\$243.2	\$209.5	\$226.5	
381	ENGINEERING	25.7	20.6	21.0	20.3	27.3	22.0	25.0	
	TOTAL ESTIMATED CONSTRUCTION COST	\$233.3	\$199.8	\$204.0	\$196.4	\$270.5	\$231.5	\$251.5	

TABLE 6 - 1
CONSTRUCTION COST SUMMARY

- b. Published trade wage rates and productivity for a Middletown, USA, site locality were used for labor costs. Rates include contractor overhead and profit.
- c. The plant site is assumed to be relatively level (cut and fill to ± 1 ft), sparsely vegetated with minimal subsurface rock formation, and good foundation bearing conditions.
- d. Coal is assumed to be delivered to the plant site by rail via unit train.
- e. AVCO factors for contingency, field engineering, and indirect costs were utilized to facilitate direct comparison with the ETF cost data bases.
- f. Engineering services were estimated on the basis of eight percent of the total direct and indirect costs. This includes preliminary and final design, procurement, construction management, and A/E fees. Special engineering services related to major MHD subsystems during construction are included as an additional charge to cover ongoing design changes.

These estimates do not include:

- a. Escalation and allowance for funds during construction (AFDC),
- b. Conceptual design and environmental studies,
- c. Development costs for critical MHD components and equipment,
- d. Operation and maintenance,
- e. Land and land rights,
- f. Rock excavation,
- g. Relocation of underground facilities,
- h. Waste product storage,
- i. Makeup water costs,
- j. Gasifier and oxygen systems,
- k. Research and simulation equipment, and

1. Other cost items such as operator training, startup costs, spare parts, government field staff, legal fees, and ad valorem taxes.

6.3.2 Comparison

o 70 MWe Class Plant

The estimated cost to retrofit a 260 MWt MHD cycle to a 70 MWe class coal-fired plant is \$200 million, a savings of \$33 million over the stand-alone ETF cost of \$233 million. This savings results from using the steam bottoming plant turbine equipment and coal handling facilities.

The cost to retrofit the same topping cycle to the existing Frank Bird plant is estimated to be \$204 million. This would be only \$4 million over the cost of retrofitting the coal-fired plant, because E.J. Corette's adjacent coal handling facilities could be modified to serve the MHD topping cycle. Retrofitting the existing Frank Bird plant would, therefore, cost \$29 million less than the stand-alone ETF.

o 125 MWe Class Plant

The retrofit of the 125 MWe class coal-fired plant and Etiwanda Unit 1 utilizes the scaled-up MHD cycle. The retrofit of the 125 MWe class plant costs an estimated \$231 million and reflects the increased size of the MHD equipment and components. This is \$39 million less than the \$270 million cost for a stand-alone ETF scaled-up to a 324 MWt size.

The cost to retrofit the scaled-up MHD cycle to the existing Etiwanda Unit is \$251 million. This exceeds the cost of retrofitting a 125 MWe coal-fired plant by \$20 million because of new coal handling and related MHD equipment and the relocation of existing facilities. Retrofitting Etiwanda Unit 1 is estimated to be \$19 million less than the scaled-up, stand-alone ETF.

o 800 MWe Class Plant

The cost of retrofitting a 260 Mwt MHD cycle to a large, high efficiency, coal-fired, baseload power plant is estimated at \$196 million, a savings of \$37 million compared to the ETF. Since the bottoming plant is assumed to be in the planning stage, its coal handling facilities would be designed to accommodate the retrofit. Compared to the 70 MWe class retrofit, a savings of \$4 million is estimated because of reduced MHD boiler rating requirements (lower steam pressure and temperature).

o Potential Savings from Fuel Costs

Retrofitting a coal-fired MHD topping cycle to the Frank Bird and Etiwanda plants would in effect be converting these plants to coal firing during the MHD operation. In view of world oil market uncertainties and rising fuel oil prices, these conversions could provide attractive fuel savings. The magnitude would depend on certain variables, such as the capacity factor of the combined plant and the relative costs of coal and seed compared to oil.

6.4 RETROFIT SCHEDULES

Schedules were developed for the retrofit plants based on conventional power plant scheduling experience and the assumption that procurement of critical MHD components is started during the preliminary design phase. Also, it is assumed that the advancement of MHD technology would be accomplished when needed to satisfy manufacturing, final design, and construction schedule requirements. These schedules correspond to those which would develop from normal practice of the electric utility industry and do not take into account the effect of government sponsored projects. Accordingly, these schedules are considered representative of the minimum times required to design and construct an ETF retrofit power facility.

Conventional power plant design and construction activities for a typical 800 MWe coal-fired plant are shown in Figure 6-4. These activities were used as a basis for preparing the retrofit schedules. Starting with the Request for Bids, 28 months of preliminary design and site work are required for the licensing phase and securing a construction permit. For detail design, procurement, construction, and checkout, 44 months are required. The total calendar time for plant construction is six years. Under ideal conditions, a coal-fired power plant could be constructed in 69 months, allowing 27 months for the licensing effort, 40 months (including a 3-month overlap with the licensing phase) for construction, and 5 months for checkout. For purposes of this study, the 72-month schedule is considered more representative and realistic for conventional plant construction.

The design and construction of an MHD retrofit in the 70 MWe and 125 MWe class, using a direct steam connection is estimated at five years. This includes preliminary and final design, procurement, construction, and checkout. This estimate assumes that licensing and construction approval can be accomplished within 16 months. Back-end schedule activities, which include procurement, construction, and checkout of the MHD topping loop, require 44 months which is similar to the back-end construction time of a conventional coal-fired plant.

The design and construction of an MHD retrofit of an 800 MWe plant, using the isolated loop scheme to power the plant auxiliaries, is estimated to require six and one-half years. This includes the six year period for the conventional plant, during which the MHD topping loop would be constructed, plus an additional six months for matching and integrating the topping side equipment and controls into a total system. Most of the topping side integration would follow the conventional plant checkout.

Under similar assumptions, it is estimated that a stand-alone ETF plant could be constructed in six and one-half years, which agrees with AVCO estimates. Depending upon the type of application, an MHD retrofit of an existing plant has the potential to reduce this time by one and one-half years. The approval process for the construction permit should be reduced. This, in turn, would allow an earlier start date for design and procurement of major equipment. Also, the construction phase would be shortened by as much as six months because of reduced construction interferences and the use of existing systems that have already been tested.

If the retrofit plan is for a new plant at a new site, no saving in schedule over a stand-alone ETF will result since the licensing, construction, and checkout for both plants would be within the same time frame.

APPENDIX A

RETROFIT PLANT CANDIDATES

APPENDIX A

RETROFIT PLANT CANDIDATES

Appendix A contains computer generated tables from information residing on two data base tapes: the "Federal Power Plant Inventory" (Power Plant) and "Power Plant Company ID" (Company). These tapes were obtained from the DOE Information Office as the result of a request under the Freedom of Information Act. The data were copied from the DOE electric utility plant data bank which is based on Federal Energy Regulatory Commission files.

The Power Plant tape contains plant and unit data for all power plants in the United States owned by public utilities as of October 1977. The Company tape contains information relating the numeric company code on the Power Plant tape to the names and locations of actual companies.

- o Table A-1 Steam Plants In Service In the United States
200 MW and Smaller
Units Commissioned 1950-1959

The criteria used for the selection of units were: steam turbine units; nameplate rating of 200 MWe or less; year of commission between 1950 and 1959 inclusive; and primary fuels in the gas, oil, and coal categories. The records were sorted by state and company.

- o Table A-2 Steam Plants Planned For Construction in the United States

The criteria used for the selection of units were: steam turbine units planned but not under construction; and primary fuels in the gas, oil, and coal categories. The records were sorted by state and company.

The primary fuel designation COAL includes coal (general), bituminous coal, subbituminous coal, anthracite coal, and lignite coal. The designation OIL includes oil (general), No. 2 fuel oil, No. 4 fuel oil, No. 5 fuel oil, No. 6 fuel oil, crude oil, and top crude oil. The

designation GAS includes gas (general), liquified natural gas, methanol, natural gas, and synthetic natural gas. The designation UNK is used wherever the primary fuel has not been determined or the actual fuel type is unknown.

[illegible]

TABLE A-1 (CONT'D.)

NAME RATING-MW	PLATE TYPE	DATE COMMISSIONED	PLANT NAME	UNIT CODE	UTILITY NAME
CALIFORNIA					
123	OIL	1953	ETIWANDA	2	SOUTHERN CALIFORNIA EDISON COMPANY
123	OIL	1953	ETIWANDA	2	SOUTHERN CALIFORNIA EDISON COMPANY
123	OIL	1953	REDONDO BEACH NO. 2	2	SOUTHERN CALIFORNIA EDISON COMPANY
123	OIL	1953	EL SEGUNDO	2	SOUTHERN CALIFORNIA EDISON COMPANY
123	OIL	1953	EL SEGUNDO	2	SOUTHERN CALIFORNIA EDISON COMPANY
123	OIL	1953	ALAMITOS	2	SOUTHERN CALIFORNIA EDISON COMPANY
123	OIL	1953	ALAMITOS	2	SOUTHERN CALIFORNIA EDISON COMPANY
123	OIL	1953	REDONDO BEACH NO. 2	2	SOUTHERN CALIFORNIA EDISON COMPANY
COLORADO					
123	COAL	1955	W N CLARK	1	CENTRAL TELEPHONE & UTIL CORP (CO)
123	COAL	1955	W N CLARK	1	CENTRAL TELEPHONE & UTIL CORP (CO)
123	GAS	1955	WOCKY FORD	1	CENTRAL TELEPHONE & UTIL CORP (CO)
123	GAS	1955	GEORGE BIRDSAL	1	COLORADO SPRINGS, CITY OF
123	GAS	1955	GEORGE BIRDSAL	1	COLORADO SPRINGS, CITY OF
123	GAS	1955	GEORGE BIRDSAL	1	COLORADO SPRINGS, CITY OF
123	COAL	1955	BULLOCK	1	COLORADO-UTE ELFC ASSN, INC
123	COAL	1955	BULLOCK	1	COLORADO-UTE ELFC ASSN, INC
123	COAL	1955	NUCLA	1	COLORADO-UTE ELFC ASSN, INC
123	COAL	1955	NUCLA	1	COLORADO-UTE ELFC ASSN, INC
123	COAL	1955	NUCLA	1	COLORADO-UTE ELFC ASSN, INC
123	GAS	1955	LAMAR	1	LAMAR, THE CITY OF UTILITIES BRD OF
123	COAL	1955	CAMEO	1	PUBLIC SERVICE CO OF COLORADO
123	COAL	1955	ARAPAHOE	1	PUBLIC SERVICE CO OF COLORADO
123	COAL	1955	ARAPAHOE	1	PUBLIC SERVICE CO OF COLORADO
123	COAL	1955	ARAPAHOE	1	PUBLIC SERVICE CO OF COLORADO
123	COAL	1955	ARAPAHOE	1	PUBLIC SERVICE CO OF COLORADO
123	COAL	1955	CHEROKEE	1	PUBLIC SERVICE CO OF COLORADO
123	COAL	1955	CHEROKEE	1	PUBLIC SERVICE CO OF COLORADO
123	OIL	1955	ALAMOSA	1	PUBLIC SERVICE CO OF COLORADO
123	OIL	1955	ZUNI	1	PUBLIC SERVICE CO OF COLORADO
123	GAS	1955	TRINIDAD	1	TRINIDAD MUN PWR & LT DEPT
123	GAS	1955	TRINIDAD	1	TRINIDAD MUN PWR & LT DEPT
CONNECTICUT					
66	OIL	1951	DEVON	3	NE UTIL:CONN. LIGHT & POWER CO
75	OIL	1954	MONTVILLE	3	NE UTIL:CONN. LIGHT & POWER CO
104	OIL	1956	DEVON	3	NE UTIL:CONN. LIGHT & POWER CO
104	OIL	1956	DEVON	3	NE UTIL:CONN. LIGHT & POWER CO
114	OIL	1956	MIDDLETOWN	3	NE UTIL:CONN. LIGHT & POWER CO
82	OIL	1957	BRIDGEPORT HARBOR	1	NE UTIL:HARTFORD ELECTRIC LIGHT CO
DELAWARE					
81	COAL	1957	INDIAN RIVER	1	DELMARVA POWER & LIGHT COMPANY
82	COAL	1957	INDIAN RIVER	1	DELMARVA POWER & LIGHT COMPANY
106	OIL	1957	EDGE MOOK	1	DELMARVA POWER & LIGHT COMPANY
106	OIL	1957	EDGE MOOK	1	DELMARVA POWER & LIGHT COMPANY
106	OIL	1957	EDGE MOOK	1	DELMARVA POWER & LIGHT COMPANY
DISTRICT OF COLUMBIA					
28	OIL	1952	BENNING	14	POTOMAC ELECTRIC POWER CO
FLORIDA					
34	OIL	1951	PALATKA	1	FLORIDA POWER & LIGHT COMPANY
161	OIL	1951	CUTLER	1	FLORIDA POWER & LIGHT COMPANY
161	OIL	1951	CUTLER	1	FLORIDA POWER & LIGHT COMPANY
161	OIL	1951	RIVIERA	1	FLORIDA POWER & LIGHT COMPANY
161	OIL	1951	CUTLER	1	FLORIDA POWER & LIGHT COMPANY
161	OIL	1951	PALATKA	1	FLORIDA POWER & LIGHT COMPANY
161	OIL	1951	LAUDERDALE	1	FLORIDA POWER & LIGHT COMPANY
161	OIL	1951	LAUDERDALE	1	FLORIDA POWER & LIGHT COMPANY
161	OIL	1951	MONT MEYERS	1	FLORIDA POWER & LIGHT COMPANY
161	OIL	1951	SANFORD	1	FLORIDA POWER & LIGHT COMPANY
161	OIL	1951	SUWANNEE RIVER	1	FLORIDA POWER CORPORATION
161	OIL	1951	SUWANNEE RIVER	1	FLORIDA POWER CORPORATION
161	OIL	1951	HIGGINS	1	FLORIDA POWER CORPORATION
161	OIL	1951	AVON PARK	1	FLORIDA POWER CORPORATION
161	OIL	1951	HIGGINS	1	FLORIDA POWER CORPORATION
161	OIL	1951	HIGGINS	1	FLORIDA POWER CORPORATION
161	OIL	1951	G E TURNER	1	FLORIDA POWER CORPORATION
161	OIL	1951	G E TURNER	1	FLORIDA POWER CORPORATION
161	OIL	1951	SUWANNEE RIVER	1	FLORIDA POWER CORPORATION
161	OIL	1951	SUWANNEE RIVER	1	FLORIDA POWER CORPORATION
161	OIL	1951	L BARTOW	1	FLORIDA POWER CORPORATION
161	OIL	1951	KING	1	FORT PIERCE UTILITIES AUTHORITY
161	OIL	1951	KING	1	FORT PIERCE UTILITIES AUTHORITY
161	OIL	1951	J. R. KELLY	1	GAINESVILLE-ALACHUA COUNTY (FLA)
161	OIL	1951	J. R. KELLY	1	GAINESVILLE-ALACHUA COUNTY (FLA)
161	COAL	1951	SCHOLTZ	1	SO CO:GULF POWER CO
161	COAL	1951	SCHOLTZ	1	SO CO:GULF POWER CO
161	GAS	1951	CRIST	1	SO CO:GULF POWER CO
161	GAS	1951	CRIST	1	SO CO:GULF POWER CO
161	OIL	1951	SOUTHSIDE	1	JACKSONVILLE ELECTRIC AUTHORITY
161	OIL	1951	SOUTHSIDE	1	JACKSONVILLE ELECTRIC AUTHORITY
161	OIL	1951	SOUTHSIDE	1	JACKSONVILLE ELECTRIC AUTHORITY
161	OIL	1951	J D KENNEDY	1	JACKSONVILLE ELECTRIC AUTHORITY
161	OIL	1951	J D KENNEDY	1	JACKSONVILLE ELECTRIC AUTHORITY
161	OIL	1951	SOUTHSIDE	1	JACKSONVILLE ELECTRIC AUTHORITY
161	OIL	1951	LAKSEN	1	LAKELAND, CITY OF DPT OF ELEC&WTR
161	OIL	1951	LAKSEN	1	LAKELAND, CITY OF DPT OF ELEC&WTR
161	OIL	1951	LAKSEN	1	LAKELAND, CITY OF DPT OF ELEC&WTR
161	OIL	1951	LAKE HIGHLAND	1	ORLANDO UTILITIES COMMISSION
161	OIL	1951	LAKE HIGHLAND	1	ORLANDO UTILITIES COMMISSION
161	OIL	1951	S O PURDUM	1	TALLAHASSEE, CITY OF
161	OIL	1951	S O PURDUM	1	TALLAHASSEE, CITY OF
161	OIL	1951	S O PURDUM	1	TALLAHASSEE, CITY OF

TABLE A-1 (CONT'D.)

NAMEPLATE RATING-MW	FUEL TYPE	DATE COMMISSIONED	PLANT NAME	UNIT CODE	UTILITY NAME
FLORIDA					
22	OIL	1975	S O PURDUM	5	TALLAHASSEE, CITY OF
22	OIL	1975	S O PURDUM	5	TALLAHASSEE, CITY OF
1	COAL	1975	F J GANNON	5	TAMPA ELECTRIC COMPANY
1	COAL	1975	F J GANNON	5	TAMPA ELECTRIC COMPANY
49	OIL	1975	HOOKERS POINT	5	TAMPA ELECTRIC COMPANY
82	OIL	1975	HOOKERS POINT	5	TAMPA ELECTRIC COMPANY
GEORGIA					
122	COAL	1950	YATES	2	SO CO: GEORGIA POWER CO
122	COAL	1950	YATES	2	SO CO: GEORGIA POWER CO
122	COAL	1950	YATES	2	SO CO: GEORGIA POWER CO
125	COAL	1950	HAMMOND	2	SO CO: GEORGIA POWER CO
125	COAL	1950	HAMMOND	2	SO CO: GEORGIA POWER CO
125	COAL	1950	HAMMOND	2	SO CO: GEORGIA POWER CO
156	COAL	1950	YATES	2	SO CO: GEORGIA POWER CO
156	COAL	1950	YATES	2	SO CO: GEORGIA POWER CO
500	OIL	1950	MC MANUS	2	SO CO: GEORGIA POWER CO
94	OIL	1950	MC MANUS	2	SO CO: GEORGIA POWER CO
38	GAS	1950	RIVERSIDE	1	SAVANNAH ELECTRIC & POWER CO
50	GAS	1950	RIVERSIDE	1	SAVANNAH ELECTRIC & POWER CO
HAWAII					
53	OIL	1950	WAI'AU	4	HAWAIIAN ELECTRIC COMPANY, INC
60	OIL	1950	MONOLULU	4	HAWAIIAN ELECTRIC COMPANY, INC
60	OIL	1950	WAI'AU	4	HAWAIIAN ELECTRIC COMPANY, INC
4	OIL	1950	WAI'AKEA	4	HAWAIIAN ELECTRIC LIGHT CO, INC
8	OIL	1950	WAI'AKEA	4	HAWAIIAN ELECTRIC LIGHT CO, INC
ILLINOIS					
86	COAL	1950	R S WALLACE	6	CENTRAL ILLINOIS LIGHT CO
114	COAL	1950	R S WALLACE	6	CENTRAL ILLINOIS LIGHT CO
69	COAL	1950	GRAND TOWER	6	CENTRAL ILLINOIS PUBLIC SERVICE CO
75	COAL	1950	HUTSONVILLE	6	CENTRAL ILLINOIS PUBLIC SERVICE CO
75	COAL	1950	HUTSONVILLE	6	CENTRAL ILLINOIS PUBLIC SERVICE CO
114	COAL	1950	GRAND TOWER	6	CENTRAL ILLINOIS PUBLIC SERVICE CO
69	COAL	1950	DIXON	6	COMMONWEALTH EDISON COMPANY
107	COAL	1950	JOLIET	6	COMMONWEALTH EDISON COMPANY
120	COAL	1950	WAUKEGAN	6	COMMONWEALTH EDISON COMPANY
159	COAL	1950	WAUKEGAN	6	COMMONWEALTH EDISON COMPANY
184	COAL	1950	RISK STREET	6	COMMONWEALTH EDISON COMPANY
188	COAL	1950	WILL COUNTY	6	COMMONWEALTH EDISON COMPANY
173	OIL	1950	RIDGELAND	6	COMMONWEALTH EDISON COMPANY
173	OIL	1950	RIDGELAND	6	COMMONWEALTH EDISON COMPANY
173	OIL	1950	RIDGELAND	6	COMMONWEALTH EDISON COMPANY
183	COAL	1950	JOPPA STEAM	6	ELECTRIC ENERGY, INC
183	COAL	1950	JOPPA STEAM	6	ELECTRIC ENERGY, INC
183	COAL	1950	JOPPA STEAM	6	ELECTRIC ENERGY, INC
183	COAL	1950	JOPPA STEAM	6	ELECTRIC ENERGY, INC
183	COAL	1950	JOPPA STEAM	6	ELECTRIC ENERGY, INC
74	COAL	1950	VERMILION	6	ILLINOIS POWER COMPANY
75	COAL	1950	HENNEPIN	6	ILLINOIS POWER COMPANY
106	COAL	1950	HENNEPIN	6	ILLINOIS POWER COMPANY
109	COAL	1950	VERMILION	6	ILLINOIS POWER COMPANY
111	COAL	1950	WOOD PIVER	6	ILLINOIS POWER COMPANY
120	COAL	1950	HENNEPIN	6	ILLINOIS POWER COMPANY
466	OIL	1950	HAVANA	6	ILLINOIS POWER COMPANY
500	OIL	1950	WOOD RIVER	6	ILLINOIS POWER COMPANY
305	OIL	1950	MOLINE	6	IOWA-ILLINOIS GAS & ELECTRIC CO
250	OIL	1950	LAKE SIDE	6	IOWA-ILLINOIS GAS & ELECTRIC CO
98	COAL	1950	VENICE NO. 2	6	UNION ELECTRIC COMPANY (MO)
100	COAL	1950	VENICE NO. 2	6	UNION ELECTRIC COMPANY (MO)
3	COAL	1950	ABBOTT	6	UNIVERSITY OF ILLINOIS
8	COAL	1950	ABBOTT	6	UNIVERSITY OF ILLINOIS
INDIANA					
12	COAL	1950	CRAWFORDSVILLE	6	CRAWFORDSVILLE ELEC LT & PWR UTIL
10	COAL	1950	FRANKFORT	6	FRANKFORT CITY LIGHT & POWER PLANT
69	COAL	1950	H T PRITCHARD	6	INDIANAPOLIS PWR & LT CO
69	COAL	1950	H T PRITCHARD	6	INDIANAPOLIS PWR & LT CO
114	COAL	1950	H T PRITCHARD	6	INDIANAPOLIS PWR & LT CO
114	COAL	1950	H T PRITCHARD	6	INDIANAPOLIS PWR & LT CO
46	OIL	1950	ELMER W STOUT	6	INDIANAPOLIS PWR & LT CO
70	COAL	1950	H T PRITCHARD	6	INDIANAPOLIS PWR & LT CO
70	COAL	1950	MICHIGAN CITY	6	NORTHERN INDIANA PUBLIC SERVICE CO
138	COAL	1950	DEAN H MITCHELL	6	NORTHERN INDIANA PUBLIC SERVICE CO
138	COAL	1950	DEAN H MITCHELL	6	NORTHERN INDIANA PUBLIC SERVICE CO
138	COAL	1950	DEAN H MITCHELL	6	NORTHERN INDIANA PUBLIC SERVICE CO
10	COAL	1950	PERU	6	PERU, CITY OF LT & PWR DEPT (IN)
25	COAL	1950	PERU	6	PERU, CITY OF LT & PWR DEPT (IN)
50	COAL	1950	NOBLESVILLE	6	PUBLIC SERVICE CO OF IND, INC
50	COAL	1950	NOBLESVILLE	6	PUBLIC SERVICE CO OF IND, INC
69	COAL	1950	EDWARDSPORT	6	PUBLIC SERVICE CO OF IND, INC
113	COAL	1950	WABASH RIVER	6	PUBLIC SERVICE CO OF IND, INC

TABLE A-1 (CONT'D.)

NAMEPLATE RATING-MW	FUEL TYPE	DATE COMMISSIONED	PLANT NAME	UNIT CODE	UTILITY NAME
INDIANA					
1113	COAL	1953	WABASH RIVER	2	PUBLIC SERVICE CO OF IND, INC
1113	COAL	1954	WABASH RIVER	2	PUBLIC SERVICE CO OF IND, INC
1113	COAL	1954	WABASH RIVER	2	PUBLIC SERVICE CO OF IND, INC
1113	COAL	1956	WABASH RIVER	2	PUBLIC SERVICE CO OF IND, INC
1113	COAL	1958	R GALLAGHER	2	PUBLIC SERVICE CO OF IND, INC
1113	COAL	1959	R GALLAGHER	2	PUBLIC SERVICE CO OF IND, INC
1113	COAL	1955	WHITewater VALLEY	1	RICHMOND POWER & LIGHT (IN)
1113	COAL	1955	CULLEY	1	SOUTHERN INDIANA GAS & ELECTRIC CO
1113	OIL	1951	OHIO RIVER	7	SOUTHERN INDIANA GAS & ELECTRIC CO
1113	COAL	1957	WASHINGTON	2	WASHINGTON CITY LT & POWER DEPT (IN)
1113	COAL	1957	WASHINGTON	2	WASHINGTON CITY LT & POWER DEPT (IN)
1113	COAL	1951	TANNERS CREEK	1	AEP: INDIANA & MICHIGAN ELECTRIC CO
1113	COAL	1952	TANNERS CREEK	2	AEP: INDIANA & MICHIGAN ELECTRIC CO
IOWA					
1113	COAL	1950	AMES	5	AMES, CITY OF ELECTRIC UTILITY
1113	COAL	1950	AMES	5	AMES, CITY OF ELECTRIC UTILITY
1113	GAS	1950	ATLANTIC	5	ATLANTIC MUN UTILITIES
1113	GAS	1950	STREET	5	CEDAR FALLS UTILITIES
1113	COAL	1950	PRAIRIE CREEK	5	CEDAR FALLS UTILITIES
1113	COAL	1951	PRAIRIE CREEK	5	CEDAR FALLS UTILITIES
1113	COAL	1958	PRAIRIE CREEK	5	CEDAR FALLS UTILITIES
1113	OIL	1957	SUMMIT LAKE	5	CEDAR FALLS UTILITIES
1113	COAL	1952	DUBUQUE	5	CEDAR FALLS UTILITIES
1113	COAL	1957	LANSING	5	CEDAR FALLS UTILITIES
1113	COAL	1954	DUBUQUE	5	CEDAR FALLS UTILITIES
1113	COAL	1953	BOONE	5	CEDAR FALLS UTILITIES
1113	COAL	1950	6TH STREET	5	CEDAR FALLS UTILITIES
1113	COAL	1955	SUTHERLAND	5	CEDAR FALLS UTILITIES
1113	COAL	1954	SUTHERLAND	5	CEDAR FALLS UTILITIES
1113	COAL	1958	COUNCIL BLUFFS	5	CEDAR FALLS UTILITIES
1113	COAL	1958	COUNCIL BLUFFS	5	CEDAR FALLS UTILITIES
1113	OIL	1954	DES MOINES	5	CEDAR FALLS UTILITIES
1113	COAL	1950	DES MOINES	5	CEDAR FALLS UTILITIES
1113	COAL	1950	CARROLL	5	CEDAR FALLS UTILITIES
1113	COAL	1950	HAWKEYE	5	CEDAR FALLS UTILITIES
1113	COAL	1950	MAYNARD	5	CEDAR FALLS UTILITIES
1113	GAS	1951	MAYNARD	5	CEDAR FALLS UTILITIES
1113	OIL	1951	KIRK	5	CEDAR FALLS UTILITIES
1113	OIL	1953	BRIDGEPORT	5	CEDAR FALLS UTILITIES
1113	OIL	1953	BRIDGEPORT	5	CEDAR FALLS UTILITIES
1113	OIL	1957	BRIDGEPORT	5	CEDAR FALLS UTILITIES
1113	COAL	1959	MUSCATINE	5	CEDAR FALLS UTILITIES
1113	GAS	1950	OWATONNA	5	CEDAR FALLS UTILITIES
1113	GAS	1957	OWATONNA	5	CEDAR FALLS UTILITIES
1113	COAL	1952	PELLA	5	CEDAR FALLS UTILITIES
1113	COAL	1951	UNIVERSITY OF IOWA	5	CEDAR FALLS UTILITIES
1113	COAL	1957	UNIVERSITY OF IOWA	5	CEDAR FALLS UTILITIES
KANSAS					
1113	GAS	1951	SEDAN	5	CANEY VALLEY ELEC COOP ASSN, INC.
1113	GAS	1954	GREAT BEND	5	CANEY VALLEY ELEC COOP ASSN, INC.
1113	GAS	1954	GREAT BEND	5	CANEY VALLEY ELEC COOP ASSN, INC.
1113	GAS	1957	MOSS BEACH	5	CANEY VALLEY ELEC COOP ASSN, INC.
1113	GAS	1951	COLBY	5	CANEY VALLEY ELEC COOP ASSN, INC.
1113	GAS	1955	COLBY	5	CANEY VALLEY ELEC COOP ASSN, INC.
1113	GAS	1950	CONCORDIA	5	CANEY VALLEY ELEC COOP ASSN, INC.
1113	GAS	1953	MULLERGRN	5	CANEY VALLEY ELEC COOP ASSN, INC.
1113	GAS	1957	MULLERGRN	5	CANEY VALLEY ELEC COOP ASSN, INC.
1113	GAS	1956	JUDSON LARGE	5	CANEY VALLEY ELEC COOP ASSN, INC.
1113	GAS	1950	COFFEYVILLE	5	CANEY VALLEY ELEC COOP ASSN, INC.
1113	GAS	1954	RIVERTON	5	CANEY VALLEY ELEC COOP ASSN, INC.
1113	GAS	1957	RIVERTON	5	CANEY VALLEY ELEC COOP ASSN, INC.
1113	GAS	1952	IOLA	5	CANEY VALLEY ELEC COOP ASSN, INC.
1113	GAS	1952	QUINDARO NO. 2	5	CANEY VALLEY ELEC COOP ASSN, INC.
1113	GAS	1955	KAW	5	CANEY VALLEY ELEC COOP ASSN, INC.
1113	GAS	1957	KAW	5	CANEY VALLEY ELEC COOP ASSN, INC.
1113	GAS	1952	MURRAY GILL	5	CANEY VALLEY ELEC COOP ASSN, INC.
1113	GAS	1954	NEOSHO	5	CANEY VALLEY ELEC COOP ASSN, INC.
1113	GAS	1954	MURRAY GILL	5	CANEY VALLEY ELEC COOP ASSN, INC.
1113	GAS	1956	MURRAY GILL	5	CANEY VALLEY ELEC COOP ASSN, INC.
1113	GAS	1950	MURRAY GILL	5	CANEY VALLEY ELEC COOP ASSN, INC.
1113	GAS	1950	HUTCHINSON	5	CANEY VALLEY ELEC COOP ASSN, INC.
1113	GAS	1950	HUTCHINSON	5	CANEY VALLEY ELEC COOP ASSN, INC.
1113	GAS	1950	HUTCHINSON	5	CANEY VALLEY ELEC COOP ASSN, INC.
1113	GAS	1950	LAWRENCE	5	CANEY VALLEY ELEC COOP ASSN, INC.
1113	GAS	1950	TECUMSEH	5	CANEY VALLEY ELEC COOP ASSN, INC.
1113	GAS	1954	LAWRENCE	5	CANEY VALLEY ELEC COOP ASSN, INC.
1113	GAS	1957	TECUMSEH	5	CANEY VALLEY ELEC COOP ASSN, INC.
1113	GAS	1950	PLANT NO. 1	5	CANEY VALLEY ELEC COOP ASSN, INC.
1113	GAS	1957	PLANT NO. 1	5	CANEY VALLEY ELEC COOP ASSN, INC.
1113	GAS	1954	GARDEN CITY	5	CANEY VALLEY ELEC COOP ASSN, INC.
1113	GAS	1956	WELLINGTON	5	CANEY VALLEY ELEC COOP ASSN, INC.
1113	GAS	1952	WINFIELD	5	CANEY VALLEY ELEC COOP ASSN, INC.
1113	GAS	1957	WINFIELD	5	CANEY VALLEY ELEC COOP ASSN, INC.
KENTUCKY					
22	COAL	1958	DALE	2	EAST KENTUCKY POWER COOPERATIVE
66	COAL	1958	DALE	1	EAST KENTUCKY POWER COOPERATIVE
66	COAL	1958	DALE	4	EAST KENTUCKY POWER COOPERATIVE

TABLE A-1 (CONT'D.)

NAME PLATE RATING-MW	FUEL TYPE	DATE COMMISSIONED	PLANT NAME	UNIT CODE	UTILITY NAME
KENTUCKY					
66	COAL	1958	DALE	3	EAST KENTUCKY POWER COOPERATIVE
1	COAL	1951	HENDERSON	4	HENDERSON MUN PWR & LT
1	COAL	1951	HENDERSON	5	HENDERSON MUN PWR & LT
1	COAL	1956	HENDERSON	6	HENDERSON MUN PWR & LT
1	COAL	1951	PINEVILLE	7	HENDERSON MUN PWR & LT
1	COAL	1953	TYHON	8	KENTUCKY UTILITIES COMPANY
1	COAL	1954	GREEN RIVER	9	KENTUCKY UTILITIES COMPANY
1	COAL	1957	E W BROWN	10	KENTUCKY UTILITIES COMPANY
1	COAL	1959	GREEN RIVER	11	KENTUCKY UTILITIES COMPANY
1	COAL	1950	PADDY'S RUN	12	KENTUCKY UTILITIES COMPANY
1	COAL	1952	PADDY'S RUN	13	KENTUCKY UTILITIES COMPANY
1	COAL	1954	CANE RUN	14	LOUISVILLE GAS & ELECTRIC CO
1	COAL	1956	CANE RUN	15	LOUISVILLE GAS & ELECTRIC CO
1	COAL	1958	CANE RUN	16	LOUISVILLE GAS & ELECTRIC CO
1	COAL	1954	CANE RUN	17	LOUISVILLE GAS & ELECTRIC CO
1	COAL	1954	OWENSBORO	18	OWENSBORO MUNICIPAL UTILITIES
1	COAL	1953	SHAWNEE	19	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	SHAWNEE	20	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	SHAWNEE	21	TENNESSEE VALLEY AUTHORITY
1	COAL	1954	SHAWNEE	22	TENNESSEE VALLEY AUTHORITY
1	COAL	1954	SHAWNEE	23	TENNESSEE VALLEY AUTHORITY
1	COAL	1954	SHAWNEE	24	TENNESSEE VALLEY AUTHORITY
1	COAL	1954	SHAWNEE	25	TENNESSEE VALLEY AUTHORITY
1	COAL	1954	SHAWNEE	26	TENNESSEE VALLEY AUTHORITY
1	COAL	1954	SHAWNEE	27	TENNESSEE VALLEY AUTHORITY
1	COAL	1954	SHAWNEE	28	TENNESSEE VALLEY AUTHORITY
1	COAL	1954	SHAWNEE	29	TENNESSEE VALLEY AUTHORITY
1	COAL	1954	SHAWNEE	30	TENNESSEE VALLEY AUTHORITY
LOUISIANA					
19	GAS	1957	D.G. HUNTER	2	ALEXANDRIA ELEC LT & PR DEPT
1	GAS	1957	D.G. HUNTER	3	ALEXANDRIA ELEC LT & PR DEPT
1	GAS	1952	COUGHLIN	4	CENTRAL LOUISIANA ELEC CO, INC
1	GAS	1953	TECHE	5	CENTRAL LOUISIANA ELEC CO, INC
1	GAS	1956	TECHE	6	CENTRAL LOUISIANA ELEC CO, INC
1	GAS	1958	COUGHLIN	7	CENTRAL LOUISIANA ELEC CO, INC
1	GAS	1951	LOUISIANA 1	8	GULF STATES UTILITIES COMPANY
1	GAS	1950	LOUISIANA 2	9	GULF STATES UTILITIES COMPANY
1	GAS	1950	LOUISIANA 3	10	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 4	11	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 5	12	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 6	13	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 7	14	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 8	15	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 9	16	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 10	17	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 11	18	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 12	19	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 13	20	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 14	21	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 15	22	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 16	23	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 17	24	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 18	25	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 19	26	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 20	27	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 21	28	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 22	29	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 23	30	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 24	31	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 25	32	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 26	33	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 27	34	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 28	35	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 29	36	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 30	37	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 31	38	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 32	39	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 33	40	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 34	41	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 35	42	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 36	43	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 37	44	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 38	45	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 39	46	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 40	47	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 41	48	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 42	49	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 43	50	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 44	51	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 45	52	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 46	53	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 47	54	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 48	55	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 49	56	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 50	57	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 51	58	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 52	59	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 53	60	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 54	61	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 55	62	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 56	63	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 57	64	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 58	65	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 59	66	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 60	67	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 61	68	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 62	69	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 63	70	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 64	71	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 65	72	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 66	73	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 67	74	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 68	75	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 69	76	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 70	77	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 71	78	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 72	79	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 73	80	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 74	81	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 75	82	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 76	83	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 77	84	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 78	85	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 79	86	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 80	87	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 81	88	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 82	89	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 83	90	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 84	91	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 85	92	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 86	93	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 87	94	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 88	95	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 89	96	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 90	97	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 91	98	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 92	99	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 93	100	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 94	101	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 95	102	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 96	103	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 97	104	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 98	105	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 99	106	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 100	107	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 101	108	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 102	109	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 103	110	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 104	111	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 105	112	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 106	113	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 107	114	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 108	115	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 109	116	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 110	117	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 111	118	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 112	119	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 113	120	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 114	121	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 115	122	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 116	123	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 117	124	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 118	125	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 119	126	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 120	127	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 121	128	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 122	129	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 123	130	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 124	131	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 125	132	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 126	133	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 127	134	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 128	135	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 129	136	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 130	137	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 131	138	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 132	139	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 133	140	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 134	141	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 135	142	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 136	143	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 137	144	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 138	145	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 139	146	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 140	147	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 141	148	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 142	149	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 143	150	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 144	151	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 145	152	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 146	153	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 147	154	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 148	155	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 149	156	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 150	157	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 151	158	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 152	159	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 153	160	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 154	161	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 155	162	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 156	163	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 157	164	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 158	165	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 159	166	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 160	167	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 161	168	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 162	169	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 163	170	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 164	171	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 165	172	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 166	173	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 167	174	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 168	175	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 169	176	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 170	177	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 171	178	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 172	179	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 173	180	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 174	181	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 175	182	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 176	183	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 177	184	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 178	185	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 179	186	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 180	187	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 181	188	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 182	189	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 183	190	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 184	191	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 185	192	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 186	193	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 187	194	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 188	195	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 189	196	GULF STATES UTILITIES COMPANY
1	GAS	1954	LOUISIANA 190	197	GULF STATES UTILITIES COMPANY
1	GAS	19			

TABLE A-1 (CONT'D.)

NAMEPLATE RATING-MW	FUEL TYPE	DATE COMMISSIONED	PLANT NAME	UNIT CODE	UTILITY NAME
MICHIGAN					
66	COAL	1950	B C COBB	3	CONSUMERS POWER COMPANY
1000	COAL	1952	L R WHITING	2	CONSUMERS POWER COMPANY
1000	COAL	1952	L R WHITING	2	CONSUMERS POWER COMPANY
1000	COAL	1953	L R WHITING	2	CONSUMERS POWER COMPANY
1000	COAL	1956	B C COBB	3	CONSUMERS POWER COMPANY
1000	COAL	1957	B C COBB	3	CONSUMERS POWER COMPANY
1000	COAL	1958	L C WEADUCK	3	CONSUMERS POWER COMPANY
1000	COAL	1958	L C WEADUCK	3	CONSUMERS POWER COMPANY
1000	COAL	1958	MISTERSKY	5	DETROIT, CITY OF PUB LIGHTING DEPT
1000	COAL	1958	MISTERSKY	5	DETROIT, CITY OF PUB LIGHTING DEPT
1000	COAL	1958	TRENTON CHANNEL	5	DETROIT, EDISON COMPANY, THE
1000	COAL	1958	ST. CLAIR	5	DETROIT, EDISON COMPANY, THE
1000	COAL	1958	ST. CLAIR	5	DETROIT, EDISON COMPANY, THE
1000	COAL	1958	ST. CLAIR	5	DETROIT, EDISON COMPANY, THE
1000	COAL	1958	ST. CLAIR	5	DETROIT, EDISON COMPANY, THE
1000	OIL	1958	CONNERS CREEK	5	DETROIT, EDISON COMPANY, THE
1000	OIL	1958	CONNERS CREEK	5	DETROIT, EDISON COMPANY, THE
1000	GAS	1959	BEACON HEATING	5	DETROIT, EDISON COMPANY, THE
1000	COAL	1958	JAMES DE YOUNG	5	HOLLAND BOARD OF PUBLIC WORKS (MI)
1000	COAL	1958	ECKERT STATION	5	LANSING, CITY OF BOARD OF WTR & LT
1000	COAL	1958	ECKERT STATION	5	LANSING, CITY OF BOARD OF WTR & LT
1000	COAL	1958	UTTAWA STREET	5	LANSING, CITY OF BOARD OF WTR & LT
1000	COAL	1958	ADVANCE	5	NORTHERN MICHIGAN ELEC COOP, INC
1000	COAL	1958	ADVANCE	5	NORTHERN MICHIGAN ELEC COOP, INC
1000	COAL	1958	BAYSIDE	5	TRAVERSE, CITY OF EL LT & PWR (MI)
1000	GAS	1958	BAYSIDE	5	TRAVERSE, CITY OF EL LT & PWR (MI)
1000	COAL	1958	PRESQUE ISLE	5	UPPER PENINSULA GENERATING CO
1000	COAL	1957	ESCANABA	5	UPPER PENINSULA POWER CO
1000	COAL	1957	ESCANABA	5	UPPER PENINSULA POWER CO
1000	GAS	1958	WYANDOTTE	5	WYANDOTTE DEPT OF MUN SERVICE
1000	GAS	1958	WYANDOTTE	5	WYANDOTTE DEPT OF MUN SERVICE
MINNESOTA					
12	OIL	1950	FOX LAKE	1	INTERSTATE POWER COMPANY
12	OIL	1951	FOX LAKE	1	INTERSTATE POWER COMPANY
12	OIL	1952	MAKSHALL	1	MAKSHALL MUNICIPAL UTILITIES (MN)
12	COAL	1953	AURORA	1	MINNESOTA POWER & LIGHT CO
12	COAL	1953	AURORA	1	MINNESOTA POWER & LIGHT CO
12	COAL	1953	CLAY BOSWELL	1	MINNESOTA POWER & LIGHT CO
12	OIL	1957	M L HIGBARD	1	MINNESOTA POWER & LIGHT CO
12	COAL	1957	NEW ULM	1	NEW ULM PUB UTILS COMM
12	COAL	1953	MINNESOTA VALLEY	1	NORTHERN STATES POWER CO
12	COAL	1952	BLACK DOG	1	NORTHERN STATES POWER CO
12	COAL	1954	BLACK DOG	1	NORTHERN STATES POWER CO
12	COAL	1955	BLACK DOG	1	NORTHERN STATES POWER CO
12	COAL	1956	HIGH BRIDGE	1	NORTHERN STATES POWER CO
12	COAL	1959	HIGH BRIDGE	1	NORTHERN STATES POWER CO
12	COAL	1950	WILMARTH	1	NORTHERN STATES POWER CO
12	COAL	1950	ORTONVILLE	1	OTTER TAIL POWER COMPANY
12	COAL	1954	MOOT LAKE	1	OTTER TAIL POWER COMPANY
12	OIL	1953	SILVER LAKE	1	ROCHESTER, CITY OF ELEC DEPT (MN)
12	OIL	1951	ELK RIVER	1	UNITED POWER ASSOCIATION
12	OIL	1950	ELK RIVER	1	UNITED POWER ASSOCIATION
12	OIL	1950	ELK RIVER	1	UNITED POWER ASSOCIATION
12	COAL	1956	WILMAR	1	WILLMAR MUNICIPAL UTIL COMM
MISSISSIPPI					
66	GAS	1951	NATCHEZ	1	MID SO:MISSISSIPPI POWER & LIGHT CO
66	GAS	1951	HEX BROWN	1	MID SO:MISSISSIPPI POWER & LIGHT CO
1000	GAS	1953	DELTA	2	MID SO:MISSISSIPPI POWER & LIGHT CO
1000	GAS	1953	DELTA	2	MID SO:MISSISSIPPI POWER & LIGHT CO
1000	COAL	1957	WATSON	2	SO CO:MISSISSIPPI POWER CO
1000	OIL	1951	SWEATT	2	SO CO:MISSISSIPPI POWER CO
1000	OIL	1953	SWEATT	2	SO CO:MISSISSIPPI POWER CO
MISSOURI					
33	GAS	1950	JIM HILL	1	MID SO:ARKANSAS-MISSOURI POWER CO
1000	COAL	1953	CHAMBERS	1	CENTRAL ELECTRIC POWER COOP
1000	COAL	1959	FULTON	1	FULTON, CITY OF (MO)
1000	COAL	1958	MANNIBAL	1	MANNIBAL BOARD OF PUBLIC WORKS
1000	GAS	1958	BLUE VALLEY	1	INDEPENDENCE, CITY OF (MO)
1000	GAS	1958	BLUE VALLEY	1	INDEPENDENCE, CITY OF (MO)
1000	COAL	1951	MAWTHORN	1	KANSAS CITY POWER & LIGHT CO
1000	COAL	1951	MAWTHORN	1	KANSAS CITY POWER & LIGHT CO
1000	COAL	1953	MAWTHORN	1	KANSAS CITY POWER & LIGHT CO
1000	COAL	1955	MAWTHORN	1	KANSAS CITY POWER & LIGHT CO
1000	COAL	1958	MAWTHORN	1	KANSAS CITY POWER & LIGHT CO
1000	COAL	1958	MONTROSE	1	KANSAS CITY POWER & LIGHT CO
1000	OIL	1951	GREEN FOREST	1	M & A ELECTRIC POWER COOPERATIVE
1000	OIL	1951	GREEN FOREST	1	M & A ELECTRIC POWER COOPERATIVE
1000	OIL	1951	GREEN FOREST	1	M & A ELECTRIC POWER COOPERATIVE
1000	OIL	1951	GREEN FOREST	1	M & A ELECTRIC POWER COOPERATIVE
1000	GAS	1954	MAKSHALL	1	MAKSHALL MUNICIPAL UTILITIES (MO)
1000	GAS	1950	MEXICO	1	MISSOURI POWER & LIGHT COMPANY
1000	GAS	1950	SEDALIA	1	MISSOURI PUBLIC SERVICE CO
1000	GAS	1954	KALPH GREEN	1	MISSOURI PUBLIC SERVICE CO
1000	GAS	1958	KALPH GREEN	1	MISSOURI PUBLIC SERVICE CO
1000	COAL	1954	MISSOURI CITY	1	N. W. ELECTRIC POWER COOP, INC.
1000	COAL	1954	MISSOURI CITY	1	N. W. ELECTRIC POWER COOP, INC.
1000	COAL	1952	SOUTH RIVER STATION	1	NORTHEAST MISSOURI ELEC PWR CO
1000	COAL	1952	SOUTH RIVER STATION	1	NORTHEAST MISSOURI ELEC PWR CO
1000	GAS	1957	JAMES RIVER	2	SPRINGFIELD UTILITIES (MO)

TABLE A-1 (CONT'D.)

NAME PLATE RATING-MW	FUEL TYPE	DATE COMMISSIONED	PLANT NAME	UNIT CODE	UTILITY NAME
MISSOURI					
22	GAS	1957	JAMES RIVER	1	SPRINGFIELD UTILITIES (MO)
25	GAS	1950	EDMOND	1	ST JOSEPH LIGHT & POWER CO
25	GAS	1951	LAKE ROAD	1	ST JOSEPH LIGHT & POWER CO
25	GAS	1957	LAKE ROAD	1	ST JOSEPH LIGHT & POWER CO
138	COAL	1953	MEKAMEC	1	UNION ELECTRIC COMPANY (MO)
138	COAL	1954	MEKAMEC	2	UNION ELECTRIC COMPANY (MO)
MONTANA					
50	COAL	1958	LEWIS & CLARK	1	MONTANA-DAROTA UTILITIES CO
69	OIL	1951	FRANK BIRD	1	MONTANA POWER COMPANY, THE
NEBRASKA					
109	GAS	1958	CANADAY	1	CENTRAL NEBRASKA PUB PWR & IRR DIST
10	COAL	1950	FREMONT NO 1	1	FREMONT DEPT OF UTILITIES
19	COAL	1957	FREMONT NO 2	2	FREMONT DEPT OF UTILITIES
16	GAS	1950	NORTH DENVER	1	FREMONT DEPT OF UTILITIES
17	GAS	1957	NORTH DENVER	1	HASTINGS UTILITIES
18	GAS	1950	LINCOLN K STREET	1	HASTINGS UTILITIES
38	COAL	1951	KRAMER	1	LINCOLN CITY OF (NE)
9	GAS	1952	BLUFFS	1	NEBRASKA PUBLIC POWER DISTRICT
18	GAS	1955	OGALLALA	1	NEBRASKA PUBLIC POWER DISTRICT
74	COAL	1950	K STREET	1	NEBRASKA PUBLIC POWER DISTRICT
109	COAL	1957	NORTH OMAHA	1	NEBRASKA PUBLIC POWER DISTRICT
109	COAL	1959	NORTH OMAHA	2	OMAHA PUBLIC POWER DISTRICT
49	OIL	1951	JONES STREET	12	OMAHA PUBLIC POWER DISTRICT
NEVADA					
50	GAS	1955	CLARK	1	NEVADA POWER COMPANY
65	GAS	1956	CLARK	2	NEVADA POWER COMPANY
NEW HAMPSHIRE					
50	OIL	1952	SCHILLER	5	PUBLIC SERVICE CO OF NEW HAMPSHIRE
50	OIL	1957	SCHILLER	6	PUBLIC SERVICE CO OF NEW HAMPSHIRE
NEW JERSEY					
27	OIL	1957	DEEPWATER	7	DEEPWATER OPERATING COMPANY
82	OIL	1958	DEEPWATER	7	DEEPWATER OPERATING COMPANY
193	COAL	1955	BURLINGTON	7	PUBLIC SERVICE ELECT AND GAS CO
119	OIL	1951	SEWAREN	4	PUBLIC SERVICE ELECT AND GAS CO
147	OIL	1953	KEARNY	6	PUBLIC SERVICE ELECT AND GAS CO
147	OIL	1953	KEARNY	7	PUBLIC SERVICE ELECT AND GAS CO
8	OIL	1950	DOWN	7	VINELAND ELECTRIC UTILITY
10	OIL	1950	DOWN	8	VINELAND ELECTRIC UTILITY
123	OIL	1950	SAYREVILLE	5	GPU: JERSEY CENTRAL POWER & LIGHT CO
123	OIL	1950	SAYREVILLE	5	GPU: JERSEY CENTRAL POWER & LIGHT CO
60	OIL	1953	WEKNER	4	GPU: JERSEY CENTRAL POWER & LIGHT CO
NEW MEXICO					
35	OIL	1951	RIO GRANDE	4	EL PASO ELECTRIC COMPANY
38	OIL	1954	RIO GRANDE	5	EL PASO ELECTRIC COMPANY
50	OIL	1957	RIO GRANDE	6	EL PASO ELECTRIC COMPANY
50	OIL	1958	RIO GRANDE	7	EL PASO ELECTRIC COMPANY
17	GAS	1954	ALGODONES	1	PLAINS ELECTRIC GEN & TRANS COOP, INC
17	GAS	1954	ALGODONES	2	PLAINS ELECTRIC GEN & TRANS COOP, INC
17	GAS	1959	ALGODONES	3	PLAINS ELECTRIC GEN & TRANS COOP, INC
6	GAS	1951	SANTA FE	1	PUBLIC SERVICE CO OF NEW MEXICO
25	GAS	1950	PERSON	2	PUBLIC SERVICE CO OF NEW MEXICO
25	GAS	1950	PERSON	3	PUBLIC SERVICE CO OF NEW MEXICO
25	GAS	1950	PERSON	4	PUBLIC SERVICE CO OF NEW MEXICO
25	GAS	1950	PERSON	5	PUBLIC SERVICE CO OF NEW MEXICO
25	GAS	1950	PERSON	6	PUBLIC SERVICE CO OF NEW MEXICO
25	GAS	1950	PERSON	7	PUBLIC SERVICE CO OF NEW MEXICO
25	GAS	1950	PERSON	8	PUBLIC SERVICE CO OF NEW MEXICO
25	GAS	1950	PERSON	9	PUBLIC SERVICE CO OF NEW MEXICO
25	GAS	1950	PERSON	10	PUBLIC SERVICE CO OF NEW MEXICO
25	GAS	1950	PERSON	11	PUBLIC SERVICE CO OF NEW MEXICO
25	GAS	1950	PERSON	12	PUBLIC SERVICE CO OF NEW MEXICO
25	GAS	1950	PERSON	13	PUBLIC SERVICE CO OF NEW MEXICO
25	GAS	1950	PERSON	14	PUBLIC SERVICE CO OF NEW MEXICO
25	GAS	1950	PERSON	15	PUBLIC SERVICE CO OF NEW MEXICO
25	GAS	1950	PERSON	16	PUBLIC SERVICE CO OF NEW MEXICO
25	GAS	1950	PERSON	17	PUBLIC SERVICE CO OF NEW MEXICO
25	GAS	1950	PERSON	18	PUBLIC SERVICE CO OF NEW MEXICO
25	GAS	1950	PERSON	19	PUBLIC SERVICE CO OF NEW MEXICO
25	GAS	1950	PERSON	20	PUBLIC SERVICE CO OF NEW MEXICO
25	GAS	1950	PERSON	21	PUBLIC SERVICE CO OF NEW MEXICO
25	GAS	1950	PERSON	22	PUBLIC SERVICE CO OF NEW MEXICO
25	GAS	1950	PERSON	23	PUBLIC SERVICE CO OF NEW MEXICO
25	GAS	1950	PERSON	24	PUBLIC SERVICE CO OF NEW MEXICO
25	GAS	1950	PERSON	25	PUBLIC SERVICE CO OF NEW MEXICO
25	GAS	1950	PERSON	26	PUBLIC SERVICE CO OF NEW MEXICO
25	GAS	1950	PERSON	27	PUBLIC SERVICE CO OF NEW MEXICO
25	GAS	1950	PERSON	28	PUBLIC SERVICE CO OF NEW MEXICO

TABLE A-1 (CONT'D.)

METER PLATE RATING-MW	FUEL TYPE	DATE COMMISSIONED	PLANT NAME	UNIT CODE	UTILITY NAME
NEW YORK					
100	OIL	1952	ALBANY	2	NIAGARA MOHAWK POWER CORP
100	OIL	1952	ALBANY	2	NIAGARA MOHAWK POWER CORP
100	OIL	1953	ALBANY	2	NIAGARA MOHAWK POWER CORP
100	OIL	1954	ALBANY	2	NIAGARA MOHAWK POWER CORP
233	OIL	1951	LOVETT	2	ORANGE AND ROCKLAND UTILITIES, INC
633	OIL	1955	LOVETT	2	ORANGE AND ROCKLAND UTILITIES, INC
633	COAL	1951	RUSSELL	2	ROCHESTER GAS & ELECTRIC CO (NY)
822	COAL	1953	RUSSELL	2	ROCHESTER GAS & ELECTRIC CO (NY)
822	COAL	1957	RUSSELL	2	ROCHESTER GAS & ELECTRIC CO (NY)
822	COAL	1959	BEE BEE	12	ROCHESTER GAS & ELECTRIC CO (NY)
NORTH CAROLINA					
46	COAL	1950	WEATHERSPOON	2	CAROLINA POWER & LIGHT CO
774	COAL	1952	WEATHERSPOON	2	CAROLINA POWER & LIGHT CO
774	COAL	1952	LEE	2	CAROLINA POWER & LIGHT CO
141	COAL	1952	LEE	2	CAROLINA POWER & LIGHT CO
188	COAL	1952	CAPE FEAR	2	CAROLINA POWER & LIGHT CO
700	COAL	1950	CAPE FEAR	2	CAROLINA POWER & LIGHT CO
700	COAL	1950	BUCK	2	DUKE POWER COMPANY
700	COAL	1950	DAN RIVER	2	DUKE POWER COMPANY
700	COAL	1950	KIVERBEND	2	DUKE POWER COMPANY
700	COAL	1950	RIVERBEND	2	DUKE POWER COMPANY
700	COAL	1950	BUCK	2	DUKE POWER COMPANY
700	COAL	1954	KIVERBEND	2	DUKE POWER COMPANY
700	COAL	1956	KIVERBEND	2	DUKE POWER COMPANY
700	COAL	1956	DAN RIVER	2	DUKE POWER COMPANY
655	COAL	1957	ALLEN	2	DUKE POWER COMPANY
655	COAL	1957	ALLEN	2	DUKE POWER COMPANY
NORTH DAKOTA					
21	COAL	1952	VELVA	1	BASIN ELECTRIC PWR COOP, INC
21	COAL	1952	VELVA	1	BASIN ELECTRIC PWR COOP, INC
21	COAL	1950	G.F. WOOD	1	MINNKOTA POWER COOP, INC
21	COAL	1951	G.F. WOOD	1	MINNKOTA POWER COOP, INC
21	COAL	1954	HESKETI	1	MONTANA-DAKOTA UTILITIES CO
OHIO					
113	COAL	1953	WALTER C BECKJORD	2	CINCINNATI GAS & ELECTRIC CO
113	COAL	1953	WALTER C BECKJORD	2	CINCINNATI GAS & ELECTRIC CO
113	COAL	1953	WALTER C BECKJORD	2	CINCINNATI GAS & ELECTRIC CO
113	COAL	1953	WALTER C BECKJORD	2	CINCINNATI GAS & ELECTRIC CO
113	COAL	1953	EASTLAKE	2	CLEVELAND ILLUM CO, THE
113	COAL	1953	EASTLAKE	2	CLEVELAND ILLUM CO, THE
113	COAL	1953	EASTLAKE	2	CLEVELAND ILLUM CO, THE
113	COAL	1953	LAKE ROAD	2	CLEVELAND PUB UTLS DEPT
113	COAL	1953	LAKE ROAD	2	CLEVELAND PUB UTLS DEPT
113	COAL	1953	POSTON	2	COLUMBUS & SOUTHERN OHIO ELEC CO
113	COAL	1953	POSTON	2	COLUMBUS & SOUTHERN OHIO ELEC CO
113	COAL	1953	PICWAY	2	COLUMBUS & SOUTHERN OHIO ELEC CO
113	COAL	1953	CONESVILLE	2	COLUMBUS & SOUTHERN OHIO ELEC CO
113	COAL	1953	CONESVILLE	2	COLUMBUS & SOUTHERN OHIO ELEC CO
113	COAL	1953	CONESVILLE	2	COLUMBUS & SOUTHERN OHIO ELEC CO
113	COAL	1953	HUTCHINGS	2	COLUMBUS & SOUTHERN OHIO ELEC CO
113	COAL	1953	HUTCHINGS	2	COLUMBUS & SOUTHERN OHIO ELEC CO
113	COAL	1953	HUTCHINGS	2	COLUMBUS & SOUTHERN OHIO ELEC CO
113	COAL	1953	HUTCHINGS	2	COLUMBUS & SOUTHERN OHIO ELEC CO
113	COAL	1953	FRANK M TAIT	2	DAYTON POWER & LIGHT COMPANY, THE
113	COAL	1953	FRANK M TAIT	2	DAYTON POWER & LIGHT COMPANY, THE
113	COAL	1953	FRANK M TAIT	2	DAYTON POWER & LIGHT COMPANY, THE
113	COAL	1953	FRANK M TAIT	2	DAYTON POWER & LIGHT COMPANY, THE
113	OIL	1951	HAMILTON	2	DAYTON POWER & LIGHT COMPANY, THE
113	COAL	1956	EAST PALESTINE	2	HAMILTON, CITY OF DEPT OF PUB UTILS
113	COAL	1956	BURGER, R F	2	OHIO EDISON COMPANY
113	COAL	1956	EDGEWATER	2	OHIO EDISON COMPANY
113	COAL	1956	NILES	2	OHIO EDISON COMPANY
113	COAL	1956	NILES	2	OHIO EDISON COMPANY
113	COAL	1956	BURGER, R F	2	OHIO EDISON COMPANY
113	COAL	1956	BURGER, R F	2	OHIO EDISON COMPANY
113	COAL	1956	SAMMIS	2	OHIO EDISON COMPANY
113	COAL	1956	PIQUA	2	OHIO EDISON COMPANY
113	COAL	1957	SAINT MARYS	2	PIQUA MUNICIPAL POWER SYSTEM
113	COAL	1957	SAINT MARYS	2	ST MARYS MUN LT & PWR PLANT
OKLAHOMA					
113	GAS	1950	CHOUTEAU	5	GRAND RIVER DAM AUTHORITY
113	GAS	1951	CHOUTEAU	5	GRAND RIVER DAM AUTHORITY
113	GAS	1951	MUSTANG	5	OKLAHOMA GAS & ELECTRIC CO
113	GAS	1951	ARBUCKLE	5	OKLAHOMA GAS & ELECTRIC CO
113	GAS	1951	MUSTANG	5	OKLAHOMA GAS & ELECTRIC CO
113	GAS	1951	MUSTANG	5	OKLAHOMA GAS & ELECTRIC CO
113	GAS	1951	MUSTANG	5	OKLAHOMA GAS & ELECTRIC CO
113	GAS	1951	MUSKOGEE LAKE	5	OKLAHOMA GAS & ELECTRIC CO
113	GAS	1951	MUSKOGEE	5	OKLAHOMA GAS & ELECTRIC CO
113	GAS	1951	SOUTHWESTERN	5	OKLAHOMA GAS & ELECTRIC CO
113	GAS	1951	SOUTHWESTERN	5	OKLAHOMA GAS & ELECTRIC CO
113	GAS	1951	TULSA	5	OKLAHOMA GAS & ELECTRIC CO
113	GAS	1951	TULSA	5	OKLAHOMA GAS & ELECTRIC CO
113	GAS	1951	TULSA	5	OKLAHOMA GAS & ELECTRIC CO
113	GAS	1951	TULSA	5	OKLAHOMA GAS & ELECTRIC CO
113	GAS	1951	ANADARKO	5	OKLAHOMA GAS & ELECTRIC CO
113	GAS	1951	ANADARKO	5	OKLAHOMA GAS & ELECTRIC CO
113	GAS	1951	ANADARKO	5	OKLAHOMA GAS & ELECTRIC CO
113	GAS	1951	ANADARKO	5	OKLAHOMA GAS & ELECTRIC CO
PENNSYLVANIA					
100	COAL	1952	ELRAMA	1	DUQUESNE LIGHT COMPANY
100	COAL	1952	ELRAMA	1	DUQUESNE LIGHT COMPANY
125	COAL	1954	ELRAMA	1	DUQUESNE LIGHT COMPANY
181	COAL	1950	F PHILLIPS	2	DUQUESNE LIGHT COMPANY
180	COAL	1956	F PHILLIPS	2	DUQUESNE LIGHT COMPANY
180	COAL	1956	F PHILLIPS	2	DUQUESNE LIGHT COMPANY
180	COAL	1956	F PHILLIPS	2	DUQUESNE LIGHT COMPANY

TABLE A-1 (CONT'D.)

NAME PLATE RATING-MW	FUEL TYPE	DATE COMMISSIONED	PLANT NAME	UNIT CODE	UTILITY NAME
PENNSYLVANIA					
75	COAL	1954	MOLTWOOD	1	PENNSYLVANIA POWER & LIGHT CO
104	COAL	1951	SUNBURY	2	PENNSYLVANIA POWER & LIGHT CO
106	COAL	1953	SUNBURY	3	PENNSYLVANIA POWER & LIGHT CO
106	COAL	1954	MARTINS CREEK	4	PENNSYLVANIA POWER & LIGHT CO
115	COAL	1956	MARTINS CREEK	5	PENNSYLVANIA POWER & LIGHT CO
134	COAL	1952	NEW CASTLE	6	PENNSYLVANIA POWER & LIGHT CO
188	COAL	1952	NEW CASTLE	7	PENNSYLVANIA POWER & LIGHT CO
200	OIL	1953	CROMBIE	8	PENNSYLVANIA POWER & LIGHT CO
200	OIL	1953	DELAWARE	9	PENNSYLVANIA POWER & LIGHT CO
200	OIL	1953	DELAWARE	10	PENNSYLVANIA POWER & LIGHT CO
200	OIL	1956	RICHMOND	11	PENNSYLVANIA POWER & LIGHT CO
200	COAL	1950	SCHUYLKILL	12	PENNSYLVANIA POWER & LIGHT CO
200	COAL	1954	HUNLOCK	13	PENNSYLVANIA POWER & LIGHT CO
200	COAL	1951	PORTLAND	14	PENNSYLVANIA POWER & LIGHT CO
200	COAL	1951	TITUS	15	PENNSYLVANIA POWER & LIGHT CO
200	COAL	1951	TITUS	16	PENNSYLVANIA POWER & LIGHT CO
200	COAL	1951	FRONT STREET	17	PENNSYLVANIA POWER & LIGHT CO
200	COAL	1950	SEWARD	18	PENNSYLVANIA POWER & LIGHT CO
200	COAL	1950	FRONT STREET	19	PENNSYLVANIA POWER & LIGHT CO
200	COAL	1950	SHAWVILLE	20	PENNSYLVANIA POWER & LIGHT CO
200	COAL	1950	SHAWVILLE	21	PENNSYLVANIA POWER & LIGHT CO
200	COAL	1957	SEWARD	22	PENNSYLVANIA POWER & LIGHT CO
200	COAL	1956	SHAWVILLE	23	PENNSYLVANIA POWER & LIGHT CO
200	COAL	1958	ARMSTRONG	24	PENNSYLVANIA POWER & LIGHT CO
200	COAL	1958	ARMSTRONG	25	PENNSYLVANIA POWER & LIGHT CO
200	COAL	1954	ARMSTRONG	26	PENNSYLVANIA POWER & LIGHT CO
200	COAL	1954	SPRINGDALE	27	PENNSYLVANIA POWER & LIGHT CO
200	OIL	1950	MILESBURG	28	PENNSYLVANIA POWER & LIGHT CO
200	OIL	1950	MILESBURG	29	PENNSYLVANIA POWER & LIGHT CO
PUERTO RICO					
50	OIL	1958	SOUTH COAST	1	PUERTO RICO WATER RESOURCES AUTH.
50	OIL	1958	SOUTH COAST	2	PUERTO RICO WATER RESOURCES AUTH.
SOUTH CAROLINA					
90	COAL	1951	LEE	2	DUKE POWER COMPANY
90	COAL	1951	LEE	3	DUKE POWER COMPANY
175	COAL	1958	LEE	4	DUKE POWER COMPANY
36	OIL	1956	GREENWOOD	5	DUKE POWER COMPANY
75	COAL	1953	URQUHART	6	SOUTH CAROLINA ELECTRIC & GAS CO
75	COAL	1954	URQUHART	7	SOUTH CAROLINA ELECTRIC & GAS CO
100	COAL	1955	URQUHART	8	SOUTH CAROLINA ELECTRIC & GAS CO
126	COAL	1956	MCMECKIN	9	SOUTH CAROLINA ELECTRIC & GAS CO
126	COAL	1956	MCMECKIN	10	SOUTH CAROLINA ELECTRIC & GAS CO
200	OIL	1950	HAGOOD	11	SOUTH CAROLINA ELECTRIC & GAS CO
200	OIL	1951	HAGOOD	12	SOUTH CAROLINA ELECTRIC & GAS CO
200	OIL	1953	JEFFERIES	13	SOUTH CAROLINA ELECTRIC & GAS CO
200	OIL	1953	JEFFERIES	14	SOUTH CAROLINA ELECTRIC & GAS CO
SOUTH DAKOTA					
17	COAL	1956	KIRK	3	BLACK HILLS PWR & LT CO
23	COAL	1951	LAWRENCE	3	NORTHERN STATES POWER CO
TENNESSEE					
0	COAL	1955	KINGSTON	6	TENNESSEE VALLEY AUTHORITY
1	COAL	1951	JOHNSONVILLE	7	TENNESSEE VALLEY AUTHORITY
1	COAL	1951	JOHNSONVILLE	8	TENNESSEE VALLEY AUTHORITY
1	COAL	1952	JOHNSONVILLE	9	TENNESSEE VALLEY AUTHORITY
1	COAL	1952	JOHNSONVILLE	10	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	11	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	12	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	13	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	14	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	15	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	16	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	17	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	18	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	19	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	20	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	21	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	22	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	23	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	24	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	25	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	26	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	27	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	28	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	29	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	30	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	31	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	32	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	33	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	34	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	35	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	36	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	37	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	38	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	39	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	40	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	41	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	42	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	43	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	44	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	45	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	46	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	47	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	48	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	49	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	50	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	51	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	52	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	53	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	54	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	55	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	56	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	57	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	58	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	59	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	60	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	61	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	62	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	63	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	64	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	65	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	66	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	67	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	68	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	69	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	70	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	71	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	72	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	73	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	74	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	75	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	76	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	77	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	78	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	79	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	80	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	81	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	82	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	83	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	84	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	85	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	86	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	87	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	88	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	89	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	90	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	91	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	92	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	93	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	94	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	95	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	96	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	97	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	98	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	99	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	100	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	101	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	102	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	103	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	104	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	105	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	106	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	107	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	108	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	109	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	110	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	111	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	112	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	113	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	114	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	115	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	116	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	117	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	118	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	119	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	120	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	121	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	122	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	123	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	124	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	125	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	126	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	127	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	128	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	129	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	130	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	131	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	132	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	133	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	134	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	135	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	136	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	137	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	138	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	139	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	140	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	141	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	142	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	143	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	144	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	145	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	146	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	147	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	148	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	149	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	150	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	151	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	152	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	153	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	154	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	155	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	156	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	157	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	158	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	159	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	160	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	161	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	162	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	163	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	164	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	165	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	166	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	167	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	168	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	169	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	170	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	171	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	172	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	173	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	174	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	175	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	176	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	177	TENNESSEE VALLEY AUTHORITY
1	COAL	1953	JOHNSONVILLE	178	TENNESSEE VALLEY AUTHORITY
1	COAL	1953			

TABLE A-1 (CONT'D.)

NAME PLATE RATING-MW	FUEL TYPE	DATE COMMISSIONED	PLANT NAME	UNIT CODE	UTILITY NAME
TEXAS					
163	GAS	1959	LON C HILL	3	CEN & SW: CENTRAL POWER & LIGHT CO
70	GAS	1951	DALLAS	3	TEXAS UTIL: DALLAS POWER & LIGHT CO
70	GAS	1954	DALLAS	3	TEXAS UTIL: DALLAS POWER & LIGHT CO
80	GAS	1953	PARKDALE	3	TEXAS UTIL: DALLAS POWER & LIGHT CO
205	GAS	1955	PARKDALE	3	TEXAS UTIL: DALLAS POWER & LIGHT CO
136	GAS	1956	MOUNTAIN CREEK	3	TEXAS UTIL: DALLAS POWER & LIGHT CO
136	GAS	1957	PARKDALE	3	TEXAS UTIL: DALLAS POWER & LIGHT CO
136	GAS	1958	MOUNTAIN CREEK	3	TEXAS UTIL: DALLAS POWER & LIGHT CO
177	GAS	1959	NORTH LAKE	3	TEXAS UTIL: DALLAS POWER & LIGHT CO
1	GAS	1955	DENTON	3	TEXAS UTIL: DALLAS POWER & LIGHT CO
1	GAS	1955	DENTON	3	DENTON MUNICIPAL UTILITIES
1	GAS	1957	C E NEWMAN	3	DENION MUNICIPAL UTILITIES
1	GAS	1957	C E NEWMAN	3	GARLAND, CITY OF
1	GAS	1955	NECHES	3	GARLAND, CITY OF
1	GAS	1955	NECHES	3	GULF STATES UTILITIES COMPANY
1	GAS	1955	NECHES	3	GULF STATES UTILITIES COMPANY
1	GAS	1955	NECHES	3	GULF STATES UTILITIES COMPANY
1	GAS	1955	NECHES	3	GULF STATES UTILITIES COMPANY
1	GAS	1955	GABLE STREET	3	GULF STATES UTILITIES COMPANY
1	GAS	1955	MIHAM CLARKE	3	HOUSTON LIGHTING & POWER CO
1	GAS	1955	MIHAM CLARKE	3	HOUSTON LIGHTING & POWER CO
1	GAS	1955	T H WHARTON	3	HOUSTON LIGHTING & POWER CO
1	GAS	1955	GREENS BAYOU	3	HOUSTON LIGHTING & POWER CO
1	GAS	1955	GREENS BAYOU	3	HOUSTON LIGHTING & POWER CO
1	GAS	1955	WEBSTER	3	HOUSTON LIGHTING & POWER CO
1	GAS	1955	WEBSTER	3	HOUSTON LIGHTING & POWER CO
1	GAS	1955	SAM BERTHON	3	HOUSTON LIGHTING & POWER CO
1	GAS	1955	W A PARISH	3	HOUSTON LIGHTING & POWER CO
1	GAS	1955	W A PARISH	3	HOUSTON LIGHTING & POWER CO
1	GAS	1955	SAM BERTHON	3	HOUSTON LIGHTING & POWER CO
1	GAS	1955	DEEPWATER	3	HOUSTON LIGHTING & POWER CO
1	GAS	1955	PLANT 2	3	HOUSTON LIGHTING & POWER CO
1	GAS	1955	PLANT 2	3	LUBBOCK, CITY OF
1	GAS	1955	PLANT 2	3	LUBBOCK, CITY OF
1	GAS	1955	PLANT 2	3	LUBBOCK, CITY OF
1	GAS	1955	PLANT 2	3	LUBBOCK, CITY OF
1	GAS	1955	LEON CREEK	3	LUBBOCK, CITY OF
1	GAS	1955	LEON CREEK	3	SAN ANTONIO PUBLIC UTILITY CO
1	GAS	1955	W B TUTTLE	3	SAN ANTONIO PUBLIC UTILITY CO
1	GAS	1955	W B TUTTLE	3	SAN ANTONIO PUBLIC UTILITY CO
1	GAS	1955	MISSION ROAD	3	SAN ANTONIO PUBLIC UTILITY CO
1	GAS	1955	LEON CREEK	3	SAN ANTONIO PUBLIC UTILITY CO
1	GAS	1955	KNOX	3	SAN ANTONIO PUBLIC UTILITY CO
1	GAS	1955	KNOX	3	CEN & SW: OUTWELL TERN
1	GAS	1955	KNOX	3	CEN & SW: OUTWELL TERN
1	GAS	1955	KNOX	3	CEN & SW: OUTWELL TERN
1	GAS	1955	KNOX	3	CEN & SW: OUTWELL TERN
1	GAS	1955	LONE STAR	3	CEN & SW: OUTWELL TERN
1	GAS	1955	MOORE COUNTY	3	SOUTHWESTERN PUBLIC UTILITY CO
1	GAS	1955	EAST PLANT	3	SOUTHWESTERN PUBLIC UTILITY CO
1	GAS	1955	PLANT X	3	SOUTHWESTERN PUBLIC UTILITY CO
1	GAS	1955	MOORE COUNTY	3	SOUTHWESTERN PUBLIC UTILITY CO
1	GAS	1955	DENVER CITY	3	SOUTHWESTERN PUBLIC UTILITY CO
1	GAS	1955	PLANT X	3	SOUTHWESTERN PUBLIC UTILITY CO
1	GAS	1955	PLANT X	3	SOUTHWESTERN PUBLIC UTILITY CO
1	GAS	1955	MORGAN CREEK	3	TEXAS UTIL: TEXAS ELECTRIC
1	GAS	1955	MORGAN CREEK	3	TEXAS UTIL: TEXAS ELECTRIC
1	GAS	1955	MORGAN CREEK	3	TEXAS UTIL: TEXAS ELECTRIC
1	GAS	1955	HANDLEY	3	TEXAS UTIL: TEXAS ELECTRIC
1	GAS	1955	MORGAN CREEK	3	TEXAS UTIL: TEXAS ELECTRIC
1	GAS	1955	NORTH MAIN	3	TEXAS UTIL: TEXAS ELECTRIC
1	GAS	1955	PEWITT BASIN	3	TEXAS UTIL: TEXAS ELECTRIC
1	GAS	1955	EAGLE MOUNTAIN	3	TEXAS UTIL: TEXAS ELECTRIC
1	GAS	1955	MORGAN CREEK	3	TEXAS UTIL: TEXAS ELECTRIC
1	GAS	1955	EAGLE MOUNTAIN	3	TEXAS UTIL: TEXAS ELECTRIC
1	GAS	1955	LAKE CREEK	3	TEXAS UTIL: TEXAS ELECTRIC
1	GAS	1955	RIVER CREST	3	TEXAS UTIL: TEXAS ELECTRIC
1	GAS	1955	COLLIN	3	TEXAS UTIL: TEXAS ELECTRIC
1	GAS	1955	STRYKER CREEK	3	TEXAS UTIL: TEXAS ELECTRIC
1	GAS	1955	LAKE PAULINE	3	TEXAS UTIL: TEXAS ELECTRIC
1	GAS	1955	PAINT CREEK	3	TEXAS UTIL: TEXAS ELECTRIC
1	GAS	1955	CONCHO	3	TEXAS UTIL: TEXAS ELECTRIC

TABLE A-1 (CONT'D..)

NAMEPLATE RATING-MW	FUEL TYPE	DATE COMMISSIONED	PLANT NAME	UNIT CODE	UTILITY NAME
VIRGINIA					
69	COAL	1950	BREMO BLUFF	3	VIRGINIA ELECTRIC & POWER CO
185	COAL	1958	BREMO BLUFF	4	VIRGINIA ELECTRIC & POWER CO
113	OIL	1953	PORTSMOUTH	1	VIRGINIA ELECTRIC & POWER CO
113	OIL	1954	PORTSMOUTH	2	VIRGINIA ELECTRIC & POWER CO
185	OIL	1959	PORTSMOUTH	3	VIRGINIA ELECTRIC & POWER CO
69	OIL	1951	POSSUM POINT	6	VIRGINIA ELECTRIC & POWER CO
113	OIL	1952	CHESTERFIELD	6	VIRGINIA ELECTRIC & POWER CO
114	OIL	1958	POSSUM POINT	6	VIRGINIA ELECTRIC & POWER CO
188	OIL	1957	YORKTOWN	6	VIRGINIA ELECTRIC & POWER CO
188	OIL	1958	YORKTOWN	6	VIRGINIA ELECTRIC & POWER CO
WASHINGTON					
25	OIL	1954	STEAM PLANT #2	2	TACOMA DEPT OF PUB UTIL (LIGHT DIV)
WEST VIRGINIA					
80	COAL	1953	KANAWHA RIVER	MP1	APP: APPALACHIAN POWER CO
80	COAL	1953	KANAWHA RIVER	MP2	APP: APPALACHIAN POWER CO
140	COAL	1953	KANAWHA RIVER	MP3	APP: APPALACHIAN POWER CO
140	COAL	1953	KANAWHA RIVER	MP4	APP: APPALACHIAN POWER CO
75	COAL	1951	RIVESVILLE	LP1	APS: MONONGAMELA POWER CO
69	COAL	1952	ALBRIGHT	6	APS: POTOMAC EDISON CO
69	COAL	1952	ALBRIGHT	7	APS: POTOMAC EDISON CO
140	COAL	1954	ALBRIGHT	8	APS: POTOMAC EDISON CO
140	COAL	1955	KAMMERER	9	APP: OHIO POWER CO
140	COAL	1955	KAMMERER	10	APP: OHIO POWER CO
140	COAL	1955	KAMMERER	11	APP: OHIO POWER CO
140	COAL	1955	KAMMERER	12	APP: OHIO POWER CO
140	COAL	1955	KAMMERER	13	APP: OHIO POWER CO
140	COAL	1955	KAMMERER	14	APP: OHIO POWER CO
140	COAL	1955	KAMMERER	15	APP: OHIO POWER CO
140	COAL	1955	KAMMERER	16	APP: OHIO POWER CO
140	COAL	1955	KAMMERER	17	APP: OHIO POWER CO
140	COAL	1955	KAMMERER	18	APP: OHIO POWER CO
140	COAL	1955	KAMMERER	19	APP: OHIO POWER CO
140	COAL	1955	KAMMERER	20	APP: OHIO POWER CO
140	COAL	1955	KAMMERER	21	APP: OHIO POWER CO
140	COAL	1955	KAMMERER	22	APP: OHIO POWER CO
140	COAL	1955	KAMMERER	23	APP: OHIO POWER CO
140	COAL	1955	KAMMERER	24	APP: OHIO POWER CO
140	COAL	1955	KAMMERER	25	APP: OHIO POWER CO
140	COAL	1955	KAMMERER	26	APP: OHIO POWER CO
140	COAL	1955	KAMMERER	27	APP: OHIO POWER CO
140	COAL	1955	KAMMERER	28	APP: OHIO POWER CO
140	COAL	1955	KAMMERER	29	APP: OHIO POWER CO
140	COAL	1955	KAMMERER	30	APP: OHIO POWER CO
140	COAL	1955	KAMMERER	31	APP: OHIO POWER CO
140	COAL	1955	KAMMERER	32	APP: OHIO POWER CO
140	COAL	1955	KAMMERER	33	APP: OHIO POWER CO
140	COAL	1955	KAMMERER	34	APP: OHIO POWER CO
140	COAL	1955	KAMMERER	35	APP: OHIO POWER CO
140	COAL	1955	KAMMERER	36	APP: OHIO POWER CO
140	COAL	1955	KAMMERER	37	APP: OHIO POWER CO
140	COAL	1955	KAMMERER	38	APP: OHIO POWER CO
140	COAL	1955	KAMMERER	39	APP: OHIO POWER CO
140	COAL	1955	KAMMERER	40	APP: OHIO POWER CO
140	COAL	1955	KAMMERER	41	APP: OHIO POWER CO
140	COAL	1955	KAMMERER	42	APP: OHIO POWER CO
140	COAL	1955	KAMMERER	43	APP: OHIO POWER CO
140	COAL	1955	KAMMERER	44	APP: OHIO POWER CO
140	COAL	1955	KAMMERER	45	APP: OHIO POWER CO
140	COAL	1955	KAMMERER	46	APP: OHIO POWER CO
140	COAL	1955	KAMMERER	47	APP: OHIO POWER CO
140	COAL	1955	KAMMERER	48	APP: OHIO POWER CO
140	COAL	1955	KAMMERER	49	APP: OHIO POWER CO
140	COAL	1955	KAMMERER	50	APP: OHIO POWER CO
140	COAL	1955	KAMMERER	51	APP: OHIO POWER CO
140	COAL	1955	KAMMERER	52	APP: OHIO POWER CO
140	COAL	1955	KAMMERER	53	APP: OHIO POWER CO
140	COAL	1955	KAMMERER	54	APP: OHIO POWER CO
140	COAL	1955	KAMMERER	55	APP: OHIO POWER CO
140	COAL	1955	KAMMERER	56	APP: OHIO POWER CO
140	COAL	1955	KAMMERER	57	APP: OHIO POWER CO
140	COAL	1955	KAMMERER	58	APP: OHIO POWER CO
140	COAL	1955	KAMMERER	59	APP: OHIO POWER CO

TABLE A-2 RETROFIT PLANT CANDIDATES STEAM PLANTS PLANNED FOR CONSTRUCTION IN THE UNITED STATES

NAME RATING-MW	PLATE FUEL TYPE	COMPLETION DATE	PLANT NAME	UNIT CODE	UTILITY NAME
ALABAMA					
718	COAL	1983	MILLER	4	SO CO:ALABAMA POWER CO
718	COAL	1982	MILLER	4	SO CO:ALABAMA POWER CO
660	COAL	1986	UNLOCATED - SITE A	A1	SO CO:ALABAMA POWER CO
660	COAL	1985	UNLOCATED - SITE A	A1	SO CO:ALABAMA POWER CO
865	COAL	1988	UNLOCATED - SITE B	B2	SO CO:ALABAMA POWER CO
865	COAL	1987	UNLOCATED - SITE B	B1	SO CO:ALABAMA POWER CO
865	COAL	1990	UNLOCATED - SITE B	B4	SO CO:ALABAMA POWER CO
865	COAL	1989	UNLOCATED - SITE B	B3	SO CO:ALABAMA POWER CO
ALASKA					
150	COAL	1983	HEALY	3	GOLDEN VALLEY ELEC ASSN. INC
ARIZONA					
204	COAL	1978	APACHE STATION	4	ARIZONA ELECTRIC PWR COOP. INC
375	COAL	1983	CHOLLA	5	ARIZONA PUBLIC SERVICE COMPANY
350	COAL	1985	SPRINGVILLE	1	TUCSON GAS & ELECTRIC COMPANY
350	COAL	1986	NEW UNIT	1	TUCSON GAS & ELECTRIC COMPANY
ARKANSAS					
800	COAL	1983	INDEPENDENCE	1	MID SO:ARKANSAS POWER & LIGHT CO
800	COAL	1985	INDEPENDENCE	2	MID SO:ARKANSAS POWER & LIGHT CO
CALIFORNIA					
800	UNK	1985	FOSSIL	2	PACIFIC GAS & ELECTRIC COMPANY
800	UNK	1984	FOSSIL	1	PACIFIC GAS & ELECTRIC COMPANY
COLORADO					
200	COAL	1985	RAY D. NIXON	2	COLORADO SPRINGS, CITY OF
380	COAL	1982	CRAIG	4	COLORADO-UTE ELEC ASSN. INC
380	COAL	1983	CRAIG	3	COLORADO-UTE ELEC ASSN. INC
330	COAL	1985	MAWHIDE	1	PLATTE RIVER POWER AUTHORITY
300	COAL	1983	SOUTHEASTERN	CO1	PUBLIC SERVICE CO OF COLORADO
300	COAL	1983	PAWNEE	CO2	PUBLIC SERVICE CO OF COLORADO
300	COAL	1985	SOUTHEASTERN	CO3	PUBLIC SERVICE CO OF COLORADO
300	COAL	1987	UNSITE	CO4	PUBLIC SERVICE CO OF COLORADO
UNK	COAL	1986	UNSITE	CO5	PUBLIC SERVICE CO OF COLORADO
800	COAL	1986	OAK CREEK	ST1	OAK CREEK POWER CO.
800	COAL	1985	OAK CREEK	ST1	OAK CREEK POWER CO.
800	COAL	1985	OAK CREEK	ST1	OAK CREEK POWER CO.
FLORIDA					
UNK	COAL	1986	FOSSIL	3	FLORIDA POWER CORPORATION
600	COAL	1984	CRYSTAL RIVER	5	FLORIDA POWER CORPORATION
600	COAL	1982	CRYSTAL RIVER	4	FLORIDA POWER CORPORATION
200	OIL	1980	UNDESIGNATED	2	FLORIDA POWER CORPORATION
250	COAL	1981	DEERHAVEN	2	GAINESVILLE-ALACHUA COUNTY (FLA)
364	COAL	1982	C.D. MCINTOSH, JR.	1	LAKELAND, CITY OF OPT OF ELEC&WTR
425	COAL	1985	BEACON KEY	1	TAMPA ELECTRIC COMPANY
486	COAL	1986	BIG BEND	4	TAMPA ELECTRIC COMPANY
600	COAL	1985	UNNAMED	2	SEMINOLE ELECTRIC COOP. INC.
600	COAL	1983	UNNAMED	1	SEMINOLE ELECTRIC COOP. INC.
GEORGIA					
825	COAL	1987	UNSITE - SITE G2	G2	SO CO:GEORGIA POWER CO
825	COAL	1986	UNSITE - SITE G1	G1	SO CO:GEORGIA POWER CO
250	COAL	1984	EFFINGHAM STATION	2	SAVANNAH ELECTRIC & POWER CO
HAWAII					
10	OIL	1983	PORT ALLEN	S2	CITIZENS UTILITIES CO
25	OIL	1986	PORT ALLEN	S3	CITIZENS UTILITIES CO
135	OIL	1980	KAME	9	HAWAIIAN ELECTRIC COMPANY, INC
163	OIL	1986	KAME	9	HAWAIIAN ELECTRIC COMPANY, INC
23	OIL	1982	W. H. HILL	7	HAWAII ELECTRIC LIGHT CO, INC
ILLINOIS					
440	COAL	1982	DUCK CREEK	2	CENTRAL ILLINOIS LIGHT CO
500	COAL	1989	DUCK CREEK	3	CENTRAL ILLINOIS LIGHT CO
600	COAL	1985	PLANT X	1	CENTRAL ILLINOIS PUBLIC SERVICE CO
600	COAL	1986	UNSITE	PD1	COMMONWEALTH EDISON COMPANY
600	COAL	1985	UNSITE	PD2	COMMONWEALTH EDISON COMPANY
600	COAL	1984	UNSITE	PD3	COMMONWEALTH EDISON COMPANY
600	COAL	1986	UNKNOWN	1/2	ILLINOIS POWER COMPANY
192	COAL	1986	UNDESIGNATED	1	SPRINGFIELD, CITY OF (IL)
100	COAL	1986	PEARL STATION	2	WESTERN ILLINOIS PWR COOP. INC
INDIANA					
11	COAL	1986	CRAWFORDSVILLE	6	CRAWFORDSVILLE ELEC LT & PWR UTIL
490	COAL	1982	MEHOM	1	HOUSIER ENERGY DIVISION OF
490	COAL	1981	MEHOM	1	HOUSIER ENERGY DIVISION OF
650	COAL	1987	PATRIOT	1	INDIANAPOLIS PWR & LT CO
650	COAL	1985	PATRIOT	1	INDIANAPOLIS PWR & LT CO
650	COAL	1982	GIBSON	1	PUBLIC SERVICE CO OF IND. INC
100	COAL	1985	WHITewater VALLEY	1	RICHMOND POWER & LIGHT (IN)
320	COAL	1987	A. B. BRUNN	1	SOUTHERN INDIANA GAS & ELECTRIC CO
320	COAL	1983	A. B. BRUNN	1	SOUTHERN INDIANA GAS & ELECTRIC CO
1300	COAL	1982	ROCKPORT (PROJ 2601)	1	AEP:INDIANA & MICHIGAN ELECTRIC CO
1300	COAL	1981	ROCKPORT (PROJ 2601)	1	AEP:INDIANA & MICHIGAN ELECTRIC CO
IOWA					
66	COAL	1980	AMES	8	AMES, CITY OF ELECTRIC UTILITY
650	COAL	1983	LOUISA	1	IOWA-ILLINOIS GAS & ELECTRIC CO
726	COAL	1981	OTTUMWA	1	IOWA SOUTHERN UTILITIES CO
160	COAL	1982	MUSCATINE	4	MUSCATINE, CITY OF

TABLE A-2 (CONT'D.)

NAME/PLATE RATING-MW	FUEL TYPE	COMPLETION DATE	PLANT NAME	UNIT CODE	UTILITY NAME
KANSAS					
300	COAL	1982	NEARMAN CREEK	2	KANSAS CITY BD OF PUB UTIL (KANS)
720	COAL	1984	JEFFREY	4	KANSAS POWER & LIGHT CO
720	COAL	1982	JEFFREY	3	KANSAS POWER & LIGHT CO
720	COAL	1980	JEFFREY	2	KANSAS POWER & LIGHT CO
KENTUCKY					
350	COAL	1985	BREC STATION 4 (CAP?)	2	BIG RIVERS ELECTRIC CORPORATION
350	COAL	1984	BREC STATION 4 (CAP?)	1	BIG RIVERS ELECTRIC CORPORATION
240	COAL	1983	COLEMAN	4	BIG RIVERS ELECTRIC CORPORATION
669	COAL	1984	EAST BEND	1	CINCINNATI GAS & ELECTRIC CO
800	COAL	1984	EAST BEND	3	CINCINNATI GAS & ELECTRIC CO
500	COAL	1984	UNDESIGNATED		EAST KENTUCKY POWER COOPERATIVE
500	COAL	1984	UNDESIGNATED - SITE A	P2	KENTUCKY UTILITIES COMPANY
556	COAL	1981	GHEINT	3	KENTUCKY UTILITIES COMPANY
556	COAL	1983	GHEINT	4	KENTUCKY UTILITIES COMPANY
495	COAL	1985	TRIMBLE COUNTY	2	LOUISVILLE GAS & ELECTRIC CO
495	COAL	1983	TRIMBLE COUNTY	1	LOUISVILLE GAS & ELECTRIC CO
675	COAL	1987	TRIMBLE COUNTY	3	LOUISVILLE GAS & ELECTRIC CO
675	COAL	1989	TRIMBLE COUNTY	4	LOUISVILLE GAS & ELECTRIC CO
LOUISIANA					
558	COAL	1983	BIG CAJUN 2	3	CAJUN ELEC POWER COOP, INC
530	COAL	1986	RODEMACHER	3	CENTRAL LOUISIANA ELEC CO, INC
615	COAL	1986	R S NELSON	6	GULF STATES UTILITIES COMPANY
615	COAL	1985	R S NELSON	5	GULF STATES UTILITIES COMPANY
700	COAL	1986	LPL-COAL UNIT		MID SOUTH LOUISIANA POWER & LIGHT CO
100	GAS	1979	MONROE	14	MONROE UTILITIES COMMISSION (LA)
50	UNK	1988	NATCHITOCHES	11	NATCHITOCHES, CITY OF
MAINE					
600	COAL	1986	SEARS ISLAND	C1	CENTRAL MAINE POWER COMPANY
MARYLAND					
800	COAL	1987	BC COAL UNIT	1	BALTIMORE GAS & ELECTRIC CO
610	OIL	1983	BRANDON SMORES	2	BALTIMORE GAS & ELECTRIC CO
610	OIL	1981	BRANDON SMORES	1	BALTIMORE GAS & ELECTRIC CO
400	COAL	1987	UNDESIGNATED	1	DELMARVA POWER & LIGHT CO OF VA
MASSACHUSETTS					
75	REF	1983	PLAINVILLE	1	MASS. MUN WHOLESALE ELEC CO
75	REF	1982	DANVERS/PEABODY	1	MASS. MUN WHOLESALE ELEC CO
MICHIGAN					
25	COAL	1982	COLDWATER	7	COLDWATER, CITY OF BD OF PUB UTILS
800	COAL	1986	UNDESIGNATED		CONSUMERS POWER COMPANY
697	COAL	1984	BELLE RIVER	2	DETROIT EDISON COMPANY, THE
697	COAL	1983	BELLE RIVER	1	DETROIT EDISON COMPANY, THE
80	COAL	1982	ISLAND	3	GRAND HAVEN BOARD OF LT & PWR
43	COAL	1982	SHIRAS	3	MARQUETTE, CITY OF BD OF LT & PWR
40	COAL	1982	UNDESIGNATED		UPPER PENINSULA POWER CO
MINNESOTA					
UNK	COAL	1984	UNDESIGNATED		MINNESOTA POWER & LIGHT CO
800	COAL	1984	FINE LAKES	1	MINNESOTA POWER & LIGHT CO
860	COAL	1987	SHERBURNE COUNTY	4	NORTHERN STATES POWER CO
860	COAL	1984	SHERBURNE COUNTY	3	NORTHERN STATES POWER CO
800	COAL	1989	UNDESIGNATED		NORTHERN STATES POWER CO
MISSISSIPPI					
700	COAL	1986	UNDESIGNATED	P2	MID SO:MISSISSIPPI POWER & LIGHT CO
700	COAL	1985	UNDESIGNATED	P1	MID SO:MISSISSIPPI POWER & LIGHT CO
548	COAL	1980	VICTOR J. DANIEL JR.	2	SO CO:MISSISSIPPI POWER CO
548	COAL	1986	UNDESIGNATED SITE A	1	SO CO:MISSISSIPPI POWER CO
MISSOURI					
670	COAL	1981	THOMAS HILL	3	ASSOCIATED ELECTRIC COOP, INC
300	COAL	1984	ASBURY	2	EMPIRE DISTRICT ELECTRIC CO
726	COAL	1987	IATAN	2	KANSAS CITY POWER & LIGHT CO
100	COAL	1985	PLANT X	1	MISSOURI PUBLIC SERVICE CO
135	COAL	1981	SIKESTON	1	SIKESTON BD OF MUN UTILITIES
250	COAL	1985	SOUTHWEST	2	SPRINGFIELD UTILITIES (MO)
MONTANA					
30	OIL	1979	GLENDIVE	GT1	MONTANA-DAKOTA UTILITIES CO
778	COAL	1982	COLSTRIP	4	MONTANA POWER COMPANY, THE
778	COAL	1980	COLSTRIP	3	MONTANA POWER COMPANY, THE
NEBRASKA					
110	COAL	1981	PLATTE	1	GRAND ISLAND WATER & LIGHT DEPT
NEVADA					
500	COAL	1985	HARRY ALLEN	1	NEVADA POWER COMPANY
500	COAL	1987	HARRY ALLEN	4	NEVADA POWER COMPANY
500	COAL	1986	HARRY ALLEN	3	NEVADA POWER COMPANY
500	COAL	1986	HARRY ALLEN	2	NEVADA POWER COMPANY
275	COAL	1984	NORTH VALMY	2	SIERRA PACIFIC POWER COMPANY
275	COAL	1981	NORTH VALMY	1	SIERRA PACIFIC POWER COMPANY
NEW JERSEY					
800	COAL	1990	GILBERT	4	GPU:JERSEY CENTRAL POWER & LIGHT CO
NEW MEXICO					
180	UNK	1982	PLAINS	1	PLAINS ELEC GEN & TRANS COOP, INC
UNK	COAL	1981	NEW MEXICO	4	PUBLIC SERVICE CO OF NEW MEXICO
UNK	COAL	1990	NEW MEXICO	2	PUBLIC SERVICE CO OF NEW MEXICO
UNK	COAL	1988	NEW MEXICO	2	PUBLIC SERVICE CO OF NEW MEXICO
UNK	COAL	1983	NEW MEXICO	1	PUBLIC SERVICE CO OF NEW MEXICO

TABLE A-2 (CONT'D.)

NAMEPLATE KATING-MW	FUEL TYPE	COMPLETION DATE	PLANT NAME	UNIT CODE	UTILITY NAME
NEW YORK					
850	COAL	1984	CAYUGA	1	NEW YORK STATE ELEC & GAS CORP
850	COAL	1987	LAKE ERIE	2	NIAGARA MOHAWK POWER CORP
850	COAL	1985	LAKE ERIE	1	NIAGARA MOHAWK POWER CORP
700	COAL	1982	700 MW FUSSIL	1	POWER AUTHORITY OF THE STATE OF NY
NORTH CAROLINA					
736	COAL	1985	MAYO	2	CAROLINA POWER & LIGHT CO
736	COAL	1983	MAYO	1	CAROLINA POWER & LIGHT CO
745	COAL	1980	ROXBORO	4	CAROLINA POWER & LIGHT CO
NORTH DAKOTA					
455	COAL	1982	ANTELOPE VALLEY	2	BASIN ELECTRIC PWR COOP. INC
455	COAL	1981	ANTELOPE VALLEY	2	BASIN ELECTRIC PWR COOP. INC
550	COAL	1979	COAL CREEK	2	COOPERATIVE POWER ASSOCIATION
550	COAL	1978	COAL CREEK	1	COOPERATIVE POWER ASSOCIATION
OHIO					
403	COAL	1987	NEWBURY	1	COLUMBUS & SOUTHERN OHIO ELEC CO
OKLAHOMA					
490	COAL	1981	CHONTEAU	1	GRAND RIVER DAM AUTHORITY
UNK	COAL	1985	SOONER	4	OKLAHOMA GAS & ELECTRIC CO
UNK	COAL	1987	UNDESIGNATED	2	OKLAHOMA GAS & ELECTRIC CO
UNK	COAL	1986	UNDESIGNATED	1	OKLAHOMA GAS & ELECTRIC CO
700	COAL	1983	SOONER	1	OKLAHOMA GAS & ELECTRIC CO
400	COAL	1983	SOUTHEAST OKLAHOMA	1	WESTERN FARMERS ELEC COOP (OK)
350	COAL	1982	EASTERN OKLAHOMA	1	WESTERN FARMERS ELEC COOP (OK)
PENNSYLVANIA					
UNK	COAL	1983	LOWER ARMSTRONG	1	APS/ALLEGHENY POWER SYSTEMS, INC.
UNK	COAL	1985	LOWER ARMSTRONG	1	APS/ALLEGHENY POWER SYSTEMS, INC.
UNK	COAL	1984	LOWER ARMSTRONG	1	APS/ALLEGHENY POWER SYSTEMS, INC.
800	COAL	1992	WEHRUM	1	PENNSYLVANIA POWER CO
800	COAL	1991	SCOTTSVILLE	1	GPU:METROPOLITAN EDISON CO
800	COAL	1986	COMO	1	GPU:PENNSYLVANIA ELECTRIC CO
800	COAL	1984	SEWARD	7	GPU:PENNSYLVANIA ELECTRIC CO
SOUTH CAROLINA					
500	COAL	1984	UNDESIGNATED	1	SOUTH CAROLINA ELECTRIC & GAS CO
315	COAL	1981	WINYAH	4	SOUTH CAROLINA PUBLIC SERVICE AUTH
315	COAL	1982	WINYAH	3	SOUTH CAROLINA PUBLIC SERVICE AUTH
TEXAS					
750	COAL	1983	FREESTONE PROJ.	1	HOUSTON LIGHTING & POWER CO
750	COAL	1984	FREESTONE PROJ.	2	HOUSTON LIGHTING & POWER CO
750	COAL	1987	W A PARKISH	1	HOUSTON LIGHTING & POWER CO
550	COAL	1979	FAYETTE	1	LOWER COLORADO RIVER AUTHORITY
550	COAL	1979	FAYETTE	1	LOWER COLORADO RIVER AUTHORITY
58	GAS	1978	HOLLY AVENUE	1	LUBBOCK, CITY OF POWER & LIGHT
375	COAL	1986	UNDESIGNATED	1	SAN ANTONIO PUBLIC SERVICE BD
343	COAL	1980	HARRINGTON	1	SOUTHWESTERN PUBLIC SERVICE CO
665	COAL	1982	TOLK STATION	1	SOUTHWESTERN PUBLIC SERVICE CO
665	COAL	1985	TOLK STATION	1	SOUTHWESTERN PUBLIC SERVICE CO
UNK	COAL	1982	CELANESE	1	SOUTHWESTERN PUBLIC SERVICE CO
591	COAL	1981	SANDOW	2	TEXAS UTIL:TEXAS POWER & LIGHT CO
793	COAL	1985	TWIN OAK	2	TEXAS UTIL:TEXAS POWER & LIGHT CO
250	UNK	1982	UNSITE	1	CEN & SW:WEST TEXAS UTILITIES CO
UTAH					
820	COAL	1987	INTERMOUNTAIN	3	LOS ANGELES DEPT OF WATER AND POWER
820	COAL	1986	INTERMOUNTAIN	2	LOS ANGELES DEPT OF WATER AND POWER
820	COAL	1985	INTERMOUNTAIN	4	LOS ANGELES DEPT OF WATER AND POWER
820	COAL	1985	INTERMOUNTAIN	1	LOS ANGELES DEPT OF WATER AND POWER
550	COAL	1984	ST. GEORGE (WAKNER)	1	NEVADA POWER COMPANY
400	COAL	1983	ST. GEORGE (WAKNER)	1	NEVADA POWER COMPANY
400	COAL	1983	EMERY	2	UTAH POWER & LIGHT COMPANY
400	COAL	1983	EMERY	3	UTAH POWER & LIGHT COMPANY
VIRGINIA					
800	COAL	1986	FOSSIL UNIT	1	VIRGINIA ELECTRIC & POWER CO
800	COAL	1987	FOSSIL UNIT	2	VIRGINIA ELECTRIC & POWER CO
WISCONSIN					
350	COAL	1979	ALMA	6	DAIRYLAND POWER COOPERATIVE
150	COAL	1986	KAUKAUNA STEAM	1	KAUKAUNA, CITY OF ELEC & WTR DEPTS
20	COAL	1979	WILDWOOD	6	MARSHFIELD ELECTRIC & WATER DEPT
400	COAL	1985	KOSHKONONG	1	WISCONSIN ELECTRIC POWER CO
400	COAL	1984	KOSHKONONG	1	WISCONSIN ELECTRIC POWER CO
617	COAL	1982	PLEASANT PRAIRIE	1	WISCONSIN ELECTRIC POWER CO
400	COAL	1983	EDGEWATER	1	WISCONSIN POWER & LIGHT CO
350	COAL	1986	WESTON	4	WISCONSIN PUBLIC SERVICE CORP
350	COAL	1982	WESTON	3	WISCONSIN PUBLIC SERVICE CORP
WYOMING					
330	COAL	1983	WYODAK	2	PACIFIC POWER & LIGHT COMPANY
550	COAL	1980	LARAMIE RIVER	2	TRI STATE GEN & TRANS ASSN. INC.
550	COAL	1983	LARAMIE RIVER	3	TRI STATE GEN & TRANS ASSN. INC.
UNSITE					
500	COAL	1984	UNSITE	1	EAST KENTUCKY POWER COOPERATIVE
250	COAL	1985	UNSITE	1	SALT RIVER PROJ AGRI IMP PWR DIST
630	COAL	1986	UNSITE	1	APS:WEST PENN POWER CO
630	COAL	1985	UNSITE	1	APS:WEST PENN POWER CO
630	COAL	1984	UNSITE	1	APS:WEST PENN POWER CO

APPENDIX B

EXISTING BOILER ANALYSIS FOR THE MHD RETROFIT PROGRAM

APPENDIX B
EXISTING BOILER ANALYSIS FOR
THE MHD RETROFIT PROGRAM

This analysis was prepared by Mechanical Technology Incorporated of Latham, New York for DOE/MHD. The report (MTI 79TR26) supports the material presented in Section 4.2 of the main report.

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ABSTRACT

Studies are currently being conducted under the direction of the Department of Energy Magnetohydrodynamics Division (DOE/MHD) to develop an approach to retrofit an existing power plant with an MHD topping cycle. Part of that effort is directed toward assessing the feasibility of using the existing boiler in the MHD Heat Recovery System and defining the MHD exhaust gas connection to the existing boiler. This report assesses the usage of the existing boiler in the MHD system.

INTRODUCTION

The concept of the MHD retrofit program evolved for the following reasons:

- As a means to provide reduced costs for the MHD ETF Program
- To provide early utility company involvement in the MHD Program
- To accelerate commercialization of the MHD Power Cycle

Since the current MHD Cycle concept is an open-cycle, MHD/steam plant, the desirable approach to the retrofit program would be to install the MHD topping cycle on an existing plant utilizing as much of the existing steam generation equipment as possible.

This report addresses the feasibility of utilizing the existing boiler in the heat recovery portion of the MHD Cycle. A range of several different size power plants were considered for this report. A description of the preferred integrated MHD Cycle is presented, and desired features of an MHD Heat Recovery/Seed Recovery (HRSR) System are identified. Existing utility boiler designs are reviewed, several different gas-side connection schemes are considered for integration of the system, and required modifications to the existing boiler are identified. An assessment of the resulting operational impact for each system is made, and recommendations for gas-side connection of the MHD Cycle are provided.

SUMMARY AND CONCLUSIONS

All of the matrices of MHD Channel/Conventional Power Plant Combinations studied have serious drawbacks, particularly where the potential for interference with conventional plant operation is concerned. Regardless of the type of gas-side connection selected, the possibility of corrosion of heat exchanger surfaces defines gas-side connections as a high-risk approach. Other factors, such as extensive modifications required (with resultant system downtime), and modification costs of the same order of magnitude as those required for a new boiler system further negate the choice of utilizing the existing boiler in the retrofit program. It is therefore recommended that separate steam generation systems be used for MHD and conventional firing operation in the retrofit program.

1.0 BACKGROUND INFORMATION

1.1 Preferred MHD/Steam Cycle

For the purposes of the retrofit study, the AVCO ETF Cycle has been selected as the preferred concept. A schematic of this system is presented in Figure 1-1. There are several features of the MHD System in general, and of the AVCO Cycle in particular, which differ significantly from conditions encountered in current coal-fired utility boilers. These are given in the following subsections.

1.1.1 Higher Temperatures

The MHD diffuser exit gas temperature is $\sim 3700^{\circ}\text{F}$, whereas conventional coal-fired systems have maximum firing temperatures of approximately 3200°F .

1.1.2 Presence of Seed Material

Whereas most fuels have merely trace quantities of potassium, the MHD gas has ~ 1 percent of potassium by weight.

1.1.3 High-Temperature Air Heater

The high degree of preheat specified for the AVCO Cycle is achieved, in part, by the use of a gas-to-gas heat exchanger in the MHD Heat Recovery System, heating air to 1100°F . Existing boilers employ air heaters to temperature levels of $\sim 500^{\circ}\text{F}$.

1.1.4 Removal and Handling of Ash/Seed Material

The particulate loading in the MHD System will be much higher than typical coal-fired boilers. Liquid and solid removal systems, including electrostatic precipitator capability, will require increased capability.

1.2 Desired MHD HRSR Features

The several functions of the MHD HRSR equipment are listed below.

- Reduce NO_x to meet environmental regulations.
- Reduce SO_x to meet environmental regulations.
- Remove coal slag.

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- Remove seed material in sufficient quantity to provide economic viability.
- Provide secondary combustion to raise overall stoichiometry to ~ 1.05 .
- Generate steam.
- Preheat air.

The Engineering Test Facility (ETF) studies have provided designs for the HRSR System to accomplish these functions. The most complete design for the system was produced in the AVCO ETF studies and will be used as the basis for this assessment. That concept is shown in Figure 1-2. NO_x decomposition is achieved in the radiant boiler section by slow, controlled cooling to $\sim 2900^\circ\text{F}$. Also in this chamber, the coal ash condenses and is removed as a liquid from the bottom of the boiler. Seed material is removed as a liquid or solid in the rest of the system as shown. Sulphur compounds are removed through use of K_2CO_3 as seed material, with the potassium and sulfur combining to form K_2SO_4 , thus removing sulfur from the gaseous products. Air heating and steam generation are achieved as shown.

1.3 Ground Rules

A set of ground rules has been established for the overall MHD Retrofit Program. These are listed below for reference. Those ground rules which have direct impact on the existing boiler analysis are discussed in the following section.

- (1) Pre-conceptual design effort
 - (2) Non-interference with bottoming plant operation
 - (3) Montana Rosebud/Illinois #6 reference coals
 - (4) AVCO ETF preferred conceptual design base (previously discussed in 1.1)
 - (5) Consideration of redundant MHD topping cycles
 - (6) Separately fired, state-of-the-art, HTAH with O_2 enrichment
- (1) The intent of this study is to provide an indication of the feasibility of utilizing the existing power plant boiler in the MHD Cycle. To accomplish this, the design of the boiler system which will be recommended for the retrofit program will be a pre-conceptual effort, in enough detail to define the configuration and provide rough costing information. This design effort will be conducted as a separate effort upon completion of the existing boiler review.

Fig. 1-2 MHD Heat Recovery System

- (2) This criteria is of prime importance in the existing boiler analysis. The boiler configuration selected must not render the basic steam plant inoperative due to corrosion/erosion problems, or must not require boiler configuration changes which would affect base steam plant operation with the MHD Cycle inoperative.
- (3) The listed coals and their characteristics affect boiler operation in terms of fouling tendencies and fusion temperatures. Alternate coal sources proposed by study participants and approved by DOE/MHD will be considered, as appropriate.
- (4) The AVCO ETF preferred conceptual design impacts the existing boiler analysis due to the different heat recovery requirements of the AVCO Cycle. This is discussed in more detail in the following sections.

2.0 ASSESSMENT OF USE OF EXISTING BOILER

From the standpoint of cost considerations and apparent system complexity, it is desirable to utilize as much of the existing power plant equipment as possible. For the existing boiler, this becomes a trade-off evaluation of minimum capital outlay versus probability of basic plant operation interruptions due to MHD exhaust gas effects on the boiler. To thoroughly assess the MHD/boiler system interface, several options have been considered, and are discussed in the following subsections.

2.1 Basic Conceptual Considerations

Introduction of the MHD channel exhaust to the boiler is considered for different gas conditioning situations. These input conditions are:

- Direct introduction of MHD exhaust at diffuser exit conditions
- Conditioning of gas to decompose NO_x and remove/condense slag
- Conditioning to decompose NO_x and remove/condense both slag and seed

Each of these three options provides unique entrance conditions to the existing boiler with the two conditioned inputs decreasing the severity of problems anticipated with the MHD gas.

The key inlet parameters for different gas input conditions are listed below:

<u>Item</u>	<u>Direct</u>	<u>Condition For NO_x/Slag</u>	<u>Condition For NO_x/Slag/Seed</u>
Gas Temperature	3750°F	2900°F	1800°F
Slag	Vapor/Liquid	Condensed	Solid
Seed	Vapor	Vapor	Mostly Solid

Problems that must be resolved for each gas input follow.

2.1.1 Direct Diffuser Exhaust Input

2.1.1.1 Inlet Temperature = 3750°F. This temperature is approximately 500°F higher than that produced in normal coal-fired furnaces. The primary effect of the increased temperature level is on materials selection.

2.1.1.2 Slag/Seed. The effect of slag and seed at the elevated temperature in the MHD system is not well understood, and programs are currently underway to document these effects in various sections of the heat recovery/seed recovery system. In general, the problems associated with slag and seed are corrosion oriented or are associated with plugging or fouling of the gas stream.

2.1.1.3 Emissions. Due to the elevated combustion temperatures, there is expected to be a considerable problem with formation of oxides of nitrogen. At the diffuser exit, the NO_x problem is expected to be severe enough so that removal will be required to meet federal emissions standards. Current conceptual designs of the MHD Heat Recovery System achieve NO_x removal through slow cooling of the MHD Channel exhaust gases at temperatures above 2900°F ^[1, 2, 3]. Decomposition of NO_x by this approach eliminates the need for a scrubber system, and it is desirable to maintain this approach for the retrofit system.

2.1.1.4 Erosion. Due to the anticipated high particulate loading in the MHD gas, it is desirable to maintain relatively low velocities on the gas side. There are two areas where the erosion problem must be carefully considered: at the boiler entry due to high velocity (240 ft/sec)^[3] of the diffuser exit gas, and through the convective passes in the boiler where the seed particles have solidified. Current practices in the utility boiler industry limit gas velocities to below approximately 75 ft/sec; this general level should be maintained.

2.1.2 Channel Exhaust Gas Conditioned for NO_x Decomposition/Slag Condensation For Removal

2.1.2.1 Elimination of Problems Associated with Direct Exhaust Input. The emissions problem is solved by the concept of slow cooling to permit decomposition of NO_x . Lowering the temperature to $\sim 2900^\circ\text{F}$ also eliminates the high temperature problem associated with direct connection.

2.1.2.2 Slag/Seed. The slag problems of the direct connection scheme are somewhat alleviated by cooling below the slag condensation temperature. Slag which condenses on cooled surfaces will obviously be removed from the gas stream; however, there will probably still be some carry-over into the existing boiler. The seed corrosion problem remains unchanged.

2.1.2.3 Erosion. The potential erosion problem is decreased only by the amount of slag removed in the conditioning section.

2.1.3 Channel Exhaust Conditioned for NO_x Decomposition/Slag and Seed Condensation for Removal

2.1.3.1 Method. This approach can be accomplished either by waterwall cooling or by recirculation and mixing of cooled exhaust stack gas to decrease gas stream temperature to the ~1800°F level. As in the previous case, slow cooling to ~2900°F is utilized to provide for NO_x decomposition, and then a more rapid quench can be used, if desired, to achieve the 1800°F level.

2.1.3.2 Seed Removal. It is anticipated that a quench approach would result in formation of sub-micron seed particles which will be difficult to remove from the gas stream.

2.1.3.3 Erosion. Again, particularly in the quench case, gas stream velocities can be expected to be quite high and erosion may be a problem.

2.2 Physical Equipment Considerations

2.2.1 Physical Connection to Boiler

In all cases considered for gas-side MHD/conventional boiler interfaces, there are serious problems to address concerning the actual connection. Existing structural work prohibits free selection of entry points. Site-specific problems must be addressed for each plant to identify such items as MHD facility location, duct routing, and entry locations.

2.2.2 Valving/Shutoff Requirements

With the gas-side connections, provisions must be made to isolate the MHD portion of the boiler system from the conventional plant for purposes of repair of failed components. Since the connection points are at high-temperature areas, the valve/closures will most likely be watercooled to provide a tight seal for worker protection.

The boiler interface options are discussed in detail in the following subsections for the MHD/boiler matches which follow.

2.3 Retrofit Case Studies

A range of power plant sizes was considered for the retrofit study to identify any size-specific problems or preferred matching of MHD cycles with existing boiler sizes. This matrix is listed below and discussed in the following subsections.

<u>Section</u>	<u>MHD</u>	<u>Existing Plant Size</u>	<u>Comments</u>
1	250 MWTh	60 MWe	Full Topping
2	250 MWTh	120 MWe	MHD Only Operation
3	250 MWTh	120 MWe	MHD & Supplementary Steam Firing
4	120 MWe	120 MWe	Full Topping
5	250 MWTh	800 MWe	MHD & Supplementary

2.3.1 250 MWTh Channel/60 MWe Steam Plant

2.3.1.1 General. Existing power plants of this size are generally non-reheat steam turbines and, therefore, have less severe steam generating requirements. The 250 MWTh channel is nearly a direct match for such a plant and could provide demonstration of a fully powered MHD/Steam Power System at ETF size without additional scaling of the MHD topping cycle. These small power plants can either be coal- or gas/oil-fired. The assessment of existing boiler usage for the MHD system has been made assuming that the boiler was either designed for coal firing or designed for future conversion to coal. Comments are presented regarding adaptation of gas/oil-fired boilers at the end of this section.

2.3.1.2 Typical Boiler Description. The general arrangement of the boiler is shown in Figure 2-1. The size and configuration is representative of boilers of this size. Pertinent design details are presented below.

<u>Item</u>	
Furnace Cross-sectional Area	380
Backpass Cross-sectional Area	275

Fig. 2-1 Typical ~200 MWth Boiler

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Item (Cont.)

Airflow Rate	.5 x 10 ⁶ PPH
Furnace Height	70 ft
Superheater Lateral Spacing	1 ft
Boiler Bank Lateral Spacing	4-6 in.
Economizer Lateral Spacing	3-4 in.
<u>Temperature Profile (Gas)</u>	
Superheater Inlet	2100
Boiler Bank Inlet	1600
Economizer Inlet	800
Air Heater Inlet	670
Stack Inlet	340
Air Inlet	400
Steam Conditions	900 psi/950°F/63100 lb/hr

2.3.1.3 Direct Connection of Diffuser Exit to Existing Boiler. Direct connection of the diffuser to the existing boiler is considered impractical due to the extensive modifications required, and the possibility that interference with normal steam generation capability could occur due to gas-side corrosion problems. The requirement for continual low-temperature air-heater cooling, requiring continual operation of the MHD air heater compressor impacts both plant output and the non-interference criteria.

The direct connection concept is illustrated in Figure 2-2 and a list of required modifications is presented in Table 1 and discussed below.

Modification to the lower waterwall of the radiant boiler is required to provide an entrance point for the MHD gas. It is desirable to introduce the MHD gas in such a manner as to avoid impinging the slag/seed-laden stream on one of the boiler walls. This could be accomplished by providing multiple entry points for the gas stream. However, existing structural supports, steam downcomers, and windbox ductwork prohibit this type of arrangement. Therefore, it is concluded that a single entry point would be utilized. The size of the opening

Fig. 2-2 Direct Connection MHD Exhaust Gas to 200 MWth Boiler

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TABLE 1
DIRECT CONNECTION BOILER MODIFICATIONS
(250 MWth Channel/60 MWe Steam Plant)

<u>Item</u>	<u>Modification</u>	<u>Reason</u>
Radiant Boiler Section	Modify lower waterwall	Provide gas entrance
	Line boiler with refractory	Decrease heat transfer capability to provide residence time above 2900°F for NOx decomposition
Superheater Section	Remove superheater	Lateral spacing inadequate
Second Pass	Add waterwall	Obtain heat transfer lost by lining radiant furnace
	Remove boiler bank/economizer sections	Temperature level too high, lateral spacing inadequate.
	Add airheater panels	No airheater to 1100°F in existing boiler
Additional Pass	Add secondary air injection.	Obtain $\phi = 1.05$
	Add respaced superheater. Add respaced boiler bank/economizer.	Removed from existing boiler
Other	Additional sootblower/cleaner ports. Ash removal/handling. ESP/baghouse modifications.	Higher MHD particulate loading

could be varied to decrease the gas velocity into the boiler. The current AVCO design would utilize a 75 sq ft opening with a gas velocity of 240 ft/sec. Enlarging the opening to 240 sq ft would decrease the velocity to a more desirable 75 ft/sec and reduce impingement problems. For either design, there results a reduction in heat transfer surface area in the radiant section, which can be compensated for by the addition of a waterwall in the second boiler pass.

In addition to the entry modification, a refractory lining would be added in this section, to (1) decrease waterwall tube corrosion, and (2) decrease heat transfer rate. The requirement for corrosion protection is well documented in other efforts and will not be detailed here. The existing boiler design results in a residence time in the radiant boiler of approximately 2 seconds, with a residence time above 2900°F for less than 1 second. With the AVCO ETF Base Cycle stoichiometry of .93, a residence time of 2 seconds is required for NO_x decomposition. Therefore, a refractory liner is required to decrease the heat transfer rate. Since the total furnace residence time is approximately 2 seconds, the temperature at the boiler exit must be 2900°F and the liner applied accordingly. The diminished effective surface area is recouped by the addition of a waterwall liner in the second pass.

The superheater section in the existing boiler is removed and repositioned in the conceptual design. Two reasons lead to this decision. First, the lateral superheater spacing is inadequate. Conceptual designs proposed in the ETF studies have proposed lateral tube spacings as shown on Figure 2-3 as a function of heater bank inlet temperature. The existing superheating spacing is 1 ft, whereas 5 ft is desired. Secondly, the AVCO ETF preferred cycle utilizes a heat exchanger in the heat recovery/seed recovery system to preheat MHD air heater inlet air to 1100°F. A large surface area is required to obtain the heat transfer. In this concept, therefore, the air heater panels were inserted in the second pass area where sufficient space is available. As noted in Figure 2-2, the modifications to the radiant section and second pass discussed in the preceding paragraphs would utilize all of the available space in the existing boiler. Additional furnace sections must be added to complete the steam generation requirements. The temperature profile in the remaining sections is set by the superheater and economizer requirements and, in turn, has been utilized to develop tube bank

Fig. 2-3 ETF Convective Pass Tube Spacing

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spacings from Figure 2-3. To insure that sufficient effective surface area is available for heat transfer, it is assumed that surface fouling in these additional sections will require a 50 percent increase in actual surface area. Secondary air must be introduced in the new S/H region to complete combustion, raising stoichiometry to ~ 1.05 .

Operational Issues. The modified conceptual design described above provides adaptation of the MHD diffuser exhaust to the existing system to enable successful operation in the MHD-fired mode, utilizing techniques and criteria established in the ETF studies. There are concerns with this system, which, by themselves, are serious enough to negate the direct connection option. A primary ground rule for this study is that the retrofit package would not impact on the existing plant power generation capability. It is not clear that this ground rule would be met. The corrosion problems associated with the seed/slag-laden MHD gases are not well documented, but existing information indicates the possibility of severe corrosion, especially at metal temperatures in excess of 1000°F. Although the steam conditions for the 60MW-type system tend to be below 1000°F, there is still a risk associated with potential corrosion and induced failure of the conventional steam equipment. In addition to the potential corrosion problem, the AVCO LTAH section also presents a unique operational problem. In the conventionally fired mode, the LTAH panels must still be cooled on the MHD gas side, since the furnace-side temperature is $\sim 2900^\circ\text{F}$. This problem could be diminished somewhat by placing the LTAH panels in a cooler region of the boiler, provided the cooling were continuous. This requires that the MHD air heater compressor be operated in the conventional mode, and the energy transferred to this stream must either be dumped or recovered in a separate system. The LTAH continual cooling requirement also impacts the ground rule of non-interference, since a compressor outage would force plant shutdown in either firing mode. Elimination of this problem can be accomplished only by modification of the AVCO Cycle to eliminate the LTAH section.

2.3.1.4. MHD Diffuser Exhaust Conditioned for NO_x Decomposition/Slag Condensation. Connection to existing boiler at this level of conditioning is not recommended for the same reasons as listed for the direct connection option - possible normal plant operation interference due to corrosion, extensive modification requirements, and LTAH continual cooling requirements.

The concept is illustrated in Figure 2-4, and a list of required modifications is presented and discussed in Table 2.

An MHD conditioning section must be designed and added to the boiler. This section would provide the slow gas cooling required for NO_x decomposition that is not provided in the radiant section of the existing boiler. Since this match is intended to provide full powering of the normal steam plant by the MHD channel, the heat removed in the conditioning section would be used in the steam generation loop. The entry into the existing boiler would be made part way up the boiler to utilize part of the waterwalls to match the total heat transfer of the radiant section under normal firing conditions. The LTAH panels would be added to the radiant section in this concept, as opposed to placement in the second pass addition in the direct fired connection. Respacing of the superheater sections requires the addition of a new boiler section downstream of the existing boiler. The previous spacing and fouling criteria were used for this concept.

Operational Issues. The same problems anticipated for the direct connect option would also exist for this design.

2.3.1.5 MHD Diffuser Exhaust Conditioned for NO_x Decomposition and Slag/Seed Solidification. Several problems associated with the direct and semi-conditioned gas streams are alleviated with this approach. However, it is concluded that the extensive modifications required and the potential corrosion problems that remain render this approach impractical.

The fully conditioned connection concept is shown in Figure 2-5. The required modifications are listed and discussed in Table 3.

The MHD conditioning section upstream of the existing boiler would take the place of the existing radiant boiler section when operating in the MHD-fired mode. The LTAH panels would be installed in this conditioning section as shown. With the MHD gas temperature reduced to 1800°F, the gas connection point to the existing boiler was chosen to be the superheater entrance, near the top of the radiant section. During periods of non-MHD operation, the MHD

Fig. 2-4 MHD Exhaust Connection Conditioned for NO_x/Slag

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TABLE 2
 NO_x/SLAG CONDITIONING BOILER MODIFICATIONS
 (250 MWth Channel/60 MWe Steam Plant)

<u>Item</u>	<u>Modification</u>	<u>Reason</u>
MHD Conditioning Section	Add new section	NO _x decomposition
Radiant Boiler Section	Add LTAH panels	No 1100°F airheater in existing boiler
	Modify waterwall	Provide gas entrance
Superheater Section	Replace superheater	Lateral spacing inadequate
	Add secondary air input	Complete combustion
Second Pass	Remove boiler bank & economizer. Add partial superheater.	Inadequate space in superheater section
Additional Pass	Add respaced boiler bank. Complete boiler bank & add economizer.	Section lateral spacing inadequate

Fig. 2-5 MHD Exhaust Connection Conditioned for NO_x /Slag/Seed

TABLE 3

NO_x SLAG/SEED BOILER MODIFICATIONS
(250 MWth Channel/60 MWe Steam Plant)

<u>Item</u>	<u>Modification</u>	<u>Reason</u>
MHD Conditioning Section	New section required	NO _x /slag/seed conditioning Secondary air inlet
Radiant Boiler Section	Modify upper waterwall	MHD gas entrance
Superheater Section	Replace superheater	Lateral spacing inadequate
Second Pass	Add partial superheater & partial boiler bank	Inadequate space in super- heater section
Additional Pass	Complete boiler bank & add economizer	Inadequate space in second pass
Other	Additional sootblower/ cleaner ports. Ash re- moval/handling. ESP/ baghouse modifications.	Higher MHD particulate loading

entrance point would be blocked off and the existing boiler combustion system and radiant furnace would be used. This concept alleviates some of the problems associated with the other gas connection options. The LTAH panels placed in the MHD conditioning section eliminate the need for cooling in the conventionally fired operational mode. Minimum modification would be required for the existing radiant boiler section. The existing windbox and fuel system can be used without modification. The upper waterwall would be altered to provide for MHD gas entrance. Modifications to the superheater and economizer as in the NO_x /Slag conditioning option are still required.

Operational Issues. The potential corrosion problems associated with seed material are diminished but not eliminated with this concept. Although most of the seed material is solidified at the MHD gas conditioner exit, effective separation of the seed from the gas stream is not a demonstrated technology. A portion of the seed material will be removed via deposition and solidification on heat exchanger surfaces, but some seed will remain in suspension in the gas stream, and will be carried over into the existing boiler. Due to the complex chemistry of the slag/seed combination, various potassium compounds can be formed that have solidification temperatures as low as 1100°F . It is conceivable, therefore, that liquid and sticky deposits will still exist on convective surfaces leading to fouling and corrosion problems. This condition interferes with the ground rule of non-interference with conventional plant operation.

2.3.2 120 MWe Existing Plant

2.3.2.1 General. There are three options for analysis in this size plant:

(1) partial power MHD only operation in the MHD mode, 250 MWth MHD cycle, (2) MHD and supplemental conventional steam firing in the MHD mode, 250 MWth MHD cycle, and (3) full power MHD only operation in the MHD mode, MHD cycle sized for 120 MWe total plant output. From the standpoint of existing boiler usage, options (1) and (3) are very similar. The key item which affects the gas connection point is the conditioned gas temperature, which is the same for each, while the items which determine the existing boiler modifications are the slag/seed presence and the LTAH requirement. Option (2) would utilize separate MHD and conventional boiler systems as shown in Figure 2-6. It is therefore not considered in this analysis.

Fig. 2-6 Case 2 - MHD/Steam Firing to 120 MWe (No Reheat In MHD HRSR)

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2.3.2.2 Boiler Description. (Etiwanda Plant #1 was used as an example.) The general arrangement of the boiler is shown in Figure 2-7. Plants of this size normally utilize a reheat-type steam turbine and the attendant heat transfer surface in the boiler. Pertinent design details are presented below.

Item

Furnace Cross-sectional Area	~800 sq ft
Second Pass Cross-sectional Area	550 sq ft
Airflow Rate	1.1×10^6 PPH
Furnace Height	70 ft
Superheater Lateral Spacing (HT Stage)	1 ft
Superheater Lateral Spacing (Initial Stage)	4 in.
Reheater Lateral Spacing	4 in.
Economizer Lateral Spacing	3 1/2 in.

Temperature Profile (Gas) °F

Superheater Inlet	2150
Reheater Inlet	1970
Economizer Inlet	800
Airheater Inlet	680
Airheater Outlet	340
Steam Conditions	1800 psi/1000°F/1000°F 835,000 lb/hr

2.3.2.3 Direct Connection Option. Direct connection is impractical. The same problems exist for the 120 MWe (either fully or partially powered unit) as would result on the 60 MWe unit, specifically: (1) extensive modification required, (2) interference with normal plant operation could result from corrosion and MHD air compressor outage, and (3) reduction in plant output due to continual compressor operation would be required.

The conceptual configuration for the direct connection is similar to the connection for the 60 MWe system as shown in Figure 2-8, with modifications given in Table 4. Whether the MHD topping cycle is either 250 MWth or sized to provide full powering for the conventional boiler, the configuration and modifica-

Fig. 2-7 Typical Coal-Fired Boiler; 120 MWe Convective Pass Arrangement

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Fig. 2-8 Direct Connection Boiler Modifications; 120 MWe

TABLE 4
DIRECT CONNECTION BOILER MODIFICATIONS
(120 MWe Existing Plant)

<u>Item</u>	<u>Modification</u>	<u>Reason</u>
Radiant Boiler	Waterwall liner	Decrease heat transfer
	Lower waterwall modification	MHD exhaust gas entrance
Superheater/Section Reheater	Remove S/H and R/H	Inadequate lateral spacing
		Revise to add LTAH
Second Pass	Add waterwall liner	Obtain effective area lost by liner in radiant section required by AVCO ETF cycle
	Remove S/H, ECON	
	Add LTAH	
New Section	Add to accommodate respaced S/H, R/H and ECON	Removed from second pass
	Add secondary air inlet	Complete combustion
Other	Additional sootblower/cleaner ports. Ash removal/handling. ESP/baghouse modifications.	Higher MHD particulate loading

tion requirements would remain the same. The spacing requirements of the convective passes are a function of fouling characteristics of the slag/seed carried in the gas stream, determined primarily by the gas temperature. The decreased particulate loading level of the partially topped system would still be ~ 3 times higher than conventional coal furnaces and would be insufficient to significantly change the lateral tube spacing requirements, hence the lack of impact on the basic design concept. The modifications utilized by this design are the same as the 60 MWe boiler except for the added complexity of re-spacing and relocating the reheater section.

Operational Issues. The operational problems are identical to the 60 MWe system, specifically, potential interference with conventional plant operation due to corrosion of the heat exchanger surfaces or outage of the MHD air heater compressor, and the net power reduction requirement required to enable continual operation of the compressor. For the case of partial powering with the MHD channel, the air compressor would most likely be electrically driven since the steam available is minimal.

2.3.2.4 MHD Channel Exhaust Gas Conditioned for NO_x /Slag. This concept is also impractical due to the extensive modifications required, the possibility of interference with conventional firing operation, and the requirement for continual LTAH cooling. The concept is illustrated in Figure 2-9 and the modifications are listed in Table 5.

Again, in regard to the direct connection concept, the design would be the same for both full and partially power MHD topping cycles, and is similar to the 60 MWe design except for the reheater section.

Operational Issues. The operational problems are unchanged for this concept relative to the direct connection option.

2.3.2.5 MHD Channel Gas Conditioned for NO_x /Slag/Seed. This concept eliminates the need for continual MHD air heater compressor operation and LTAH panel cooling. The extensive modifications required and the potential of conventional operation interruption due to corrosion render this approach impractical. The conceptual design for this connection is shown in Figure 2-10 and modifications are listed

Fig. 2-9 MHD Exhaust Conditioned for NO_x /Slag; 120 MWe

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TABLE 5
 NO_x/SLAG BOILER MODIFICATIONS
 (120 MWe Existing Plant)

<u>Item</u>	<u>Modification</u>	<u>Reason</u>
MHD Conditioning Section	Add new section	NO _x control/slag condensation
Radiant Boiler Section	Add waterwall liner	Decrease heat transfer rate
	Add LTAH panels	Required for AVCO ETF cycle
Superheater/Reheater Section	Respace S/H	Inadequate lateral spacing
	Add secondary air inlet	Complete combustion
	Remove R/H	Inadequate volume
Second Pass	Remove initial S/H & ECON	Respaced R/H insertion
	Install respaced R/H	Inadequate lateral spacing
Additional Pass	Accommodate initial S/H and ECON	Removed from second pass

Fig. 2-10 MHD Exhaust Conditioned for NO_x/Slag/Seed 120 MWe

in Table 6. This concept would be the same for either full or partial powering and similar to the 60 MWe design.

Operational Issues. As with the 60 MWe design, this approach eliminates the need for continual LTAH panel cooling and resultant compressor operation by placement of the LTAH panels in a section not used during conventional operation. The potential corrosion problem due to seed deposition, however, is not eliminated.

2.3.3 250 MWth Channel/800 MWe Steam Plant

It is assumed, for the purpose of this analysis, that this power station does not currently exist, but the design would be based on an existing power plant of the same size. Furthermore, operation in the MHD-fired configuration would be bi-modal, requiring supplementary steam firing with the conventional combustion source. The exhaust gas connection to the existing boiler could be at the same three conditions as studied in Subsections 2.3.1 and 2.3.2, and could either be introduced into the entire boiler, or confined to a part of that boiler by partitioning. These approaches are discussed in the following subsections.

2.3.3.1 Ducting of MHD Exhaust Gas into Entire Boiler. This approach is considered impractical from the standpoint of potential corrosion problems, regardless of the level of gas conditioning selected. Boiler design modifications deviating from standard practices would be desirable to avoid convective pass fouling problems due to seed. Cost to modify a boiler design to incorporate materials and spacing desired for MHD would be prohibitive.

Direct Connection Option. This option would require a considerable redesign of the entire boiler. Most radiant boiler sections have residence times of less than one second at temperatures exceeding 2900°F and would not provide sufficient residence time for NO_x decomposition. The NO_x concentration in the flue gas would be greatly reduced in this case, since the MHD channel flow is only ~10 percent of the total combustion gas flow. A detailed kinetic calculation would be required to determine the extent of redesign required to achieve adequate NO_x decomposition.

TABLE 6
 NO_x/SLAG/SEED BOILER MODIFICATIONS
 (120 MWe Existing Plant)

<u>Item</u>	<u>Modification</u>	<u>Reason</u>
MHD Conditioning Section	Add new section	Provide NO _x control Condense slag Condense seed
	Secondary air inlet	Complete combustion
Radiant Section	Upper waterwall	Provide MHD gas entrance
Superheater/Reheater Section	Respace S/H	Inadequate lateral spacing
	Remove R/H	Inadequate volume
Second Pass	Remove initial S/H & ECON	Provide for R/H installa- tion
	Install R/H	Removed from previous section
Additional Pass	Add new section	Install initial S/H & ECON

Although the particulate concentration is, in this case, reduced by a factor of 10 relative to a full-powered boiler, the primary resultant effect would be that the amount of time required to deposit a given amount of corrosive material is increased. The basic corrosion mechanism due to potassium compound deposition on metallic surfaces is still present, and there is little reason to suspect that corrosion rates would be greatly reduced due to the reduced seed/slag concentration.

In addition, the fouling tendencies of the seed/slag compounds, although decreased somewhat by the reduction in concentration, will still be extremely high relative to conventional gas streams, and modification to lateral tube spacing would be required. As for other applications, the addition of LTAH panels in the conventional boiler requires that continual cooling be provided, which, in turn, would require continual air heater compressor usage.

Operational Issues. The problems associated with corrosion could interfere with conventionally fired plant operation, as discussed. Again, the reduction in net plant output and possible shutdown due to LTAH air heater compressor requirements are a problem.

MHD Exhaust Gas Conditioned for NO_x /Slag. Introduction of conditioned gas could be accomplished part way up the radiant section waterwall with minor design alterations. The potential corrosion and LTAH problems discussed in the direct connection concept remain essentially unchanged in this case. Operational issues are unchanged from previous sections.

MHD Exhaust Gas Conditioned for NO_x /Slag/Seed. With this concept, the LTAH panels would be placed outside the conventional boiler and MHD gas introduced at the superheater bank, as in cases for other size boilers, thus eliminating the continual cooling problem. However, the convective pass corrosion problem still exists. As mentioned previously, although conditioning to solidify most of the seed is accomplished, separation of that seed remains a problem and the presence of low melting temperature compounds can be expected to cause corrosion on the heat exchange surfaces.

Operational Issues. The problem of possible interference with conventionally fired plant output is still present due to potential corrosion problems.

2.3.3.2 Ducting of MHD Gas into Partitioned Boiler. This approach, in practice, requires two separate boiler systems. The partition wall must be water cooled by the water from both systems on either side and, hence, is really two boilers. The non-MHD boiler must be designed for full plant capacity, and, as such, the MHD portion does not decrease system cost.

The MHD gas provides approximately 10 percent of the total heat input required for the 800 MWe output. Therefore, it is conceivable, that the boiler could be partitioned 90/10 to accommodate the MHD gas, with the same net effect as having separate steam-generating systems. In order to ensure base load capability, however, the non-MHD boiler portion would be required to produce 100 percent of the steam requirements in the event of outages of the MHD portion.

Direct Connection, Conditioned for NO_x/Slag. These two options are considered in the same section due to the similar problems anticipated. LTAH panels requiring constant cooling could still be in part of the conventional boiler, and the net plant output impact due to compressor operation and the additional impact of compressor outage would dictate the need for a design for the non-MHD boiler portion capable of operating at full-plant output for a potentially significant portion of the time. The actual percentage of time required for high output operation would have to be determined by an assessment of compressor outage and anticipated corrosion failures. For the purposes of this study, it was felt that such an assessment was unwarranted.

MHD Gas Conditioned for NO_x/Slag/Seed. As in other configurations for this level of gas conditioning, the LTAH panels are not part of the conventionally fired gas path, and, hence, will not affect non-MHD operation. The problem of corrosion could still cause a shutdown of the MHD portion of the boiler. If, however, the remainder of the boiler is designed for 100 percent capability, the full plant power can be achieved. The amount of time required for over capacity operation is minimized, and this approach appears to offer the highest potential for success of all combinations studied. Nonetheless, this approach should in no way be considered as an integrated MHD/conventional plant. The boiler sections, as mentioned previously, are completely separated.

2.3 Use of Exhaust Stack Gas for Quenching

This concept has been considered as an alternative to waterwall or convective pass cooling to provide for condensation/solidification of seed material to prevent formation of sticky deposits on tube banks, thereby decreasing plugging problems and also preventing liquid seed deposits on metallic surfaces to minimize corrosion problems. This approach was considered for the retrofit program, but detailed analysis was not conducted.

In order to quench the MHD gas flow from 2900°F to 1800°F to solidify seed, approximately 75 percent of stack gas at 300°F would be required for circulation (Fig. 2-11). Two effects of this recycle would effectively eliminate this concept from consideration: (1) Erosion - with the 75 percent increase in flow rate, increased particle velocity would drastically increase erosion potential and jeopardize conventional plant operation. (2) With the gas entrance temperature to the superheater LTAH now at 1800°F, and with the corresponding decrease in system log mean temperature difference, the surface areas required for heat transfer would increase drastically. This approach is considered impractical for the retrofit program.

2.4 Cost and Insurance Considerations

2.4.1 Costs

A goal of use of the existing boiler in the retrofit program is to minimize the cost associated with the overall facility. It is concluded that use of the existing boiler would not provide lower costs than construction of a separate boiler system. Two items contribute to this conclusion - the extensive boiler modification required, and the interface/connection requirements to the MHD channel.

Existing boiler modifications, as an order-of-magnitude assessment, would be more costly than construction of a new MHD heat recovery (boiler) system. For all existing boilers evaluated (subsections 2.1, 2.2 and 2.3) modifications require, essentially:

- Replacement of all boiler internals
- Addition of new boiler sections

Fig. 2-11 Connection - Conditioned for NO_x /Slag/Seed Recycle Quench

- Possible modification of circulation systems
- Possible structural modifications.

Current experience in the industry has shown that a relatively minor modification, such as conversion of an existing boiler (originally designed for future coal firing) from oil/gas to actual coal firing, is of the same order of magnitude as construction of a new coal-fired boiler. Conversion of an existing boiler to a use for which it was not originally intended requires extensive additional design effort and field labor. A detailed analysis would be required to provide detailed cost information for a thorough assessment of this trade. Boiler industry opinion indicates, however, that costs would not be reduced by use of the existing boiler.

An additional cost impact results from the connection of the MHD gas stream to the existing boiler. The actual costs will be site-specific. They will, however, include:

- Costs of ductwork from the MHD channel site to the boiler
- Relocation of any equipment required to route the ductwork
- Provision for a gas entrance to the existing boiler
- Requirement for the ability to isolate the existing boiler from the MHD system for operation in the conventional firing mode.

As noted in Section 2.2, this later requirement will probably involve a large, water-cooled shutoff, which will be a substantial cost item. None of these connection costs would be incurred with a separate system.

2.4.2 Insurance

Modification of an existing boiler requires that: (1) all changes meet existing codes, and that (2) remaining portions of the boiler be upgraded as necessary to also meet existing codes. The modifications contemplated for use of the existing boiler in the retrofit system are outside the realm of experience to date, and the insurance impact is, therefore, unclear. Insurance rates are traditionally based on known operational experience and documented failure rates.

With the lack of operational experience for an MHD/Steam System such as that contemplated for the retrofit program, this system would be classified similar to a prototype system, and it is anticipated that insurance rates would be high. An in-depth review by the insurance community would be required to quantify the anticipated rates.

APPENDIX C

DETAILED RETROFIT POWER CYCLE ASSESSMENT

APPENDIX C
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APPENDIX C
DETAILED POWER CYCLE ASSESSMENT

1.0 INTRODUCTION

Steam power plants of 70, 125, and 800 MWe nominal capacity were considered as candidates for MHD retrofit applications. Using the reference MHD system as the base for the topping cycle, several retrofit power cycle schemes for each power plant class were investigated. The following factors had significant effect on the overall plant performance and were incorporated into the analyses:

- o High pressure feedwater heaters out of service.
- o Integrating the waste heat from the MHD generator into feedwater heating.
- o Condenser pressure.
- o Applying the scaled-up MHD topping cycle.
- o Heating capacity of the economizer section.
- o Using the partially fired existing boiler in conjunction with the MHD system.
- o Supplying MHD generated steam only to the top feedwater heater and the auxiliaries of the main steam plant.

This appendix contains detailed discussions for each of the power cycle case studies. The results of all the retrofit power cycle analyses are summarized in Table C-1.

2.0 ALTERNATE INTEGRATION SCHEMES

2.1 70 MWe Class

During the evaluation process, consideration was given to fully powering the 70 MWe class plant turbine with the MHD topping cycle system. Two possible integrations were evaluated.

In the first scheme, the topping cycle was integrated with the Frank Bird plant. The compressor of the topping cycle was driven by an electric motor. To keep the turbine output at 70 MWe nominal, the economizer of the topping cycle had to be derated. All the waste heat from the MHD loop was recovered in this scheme.

For the second scheme, all the feedwater heaters of the Frank Bird turbine were kept intact. The temperature of the feedwater entering the MHD system was sufficiently high that the waste heat from the MHD generator had to be rejected to a separate cooling loop.

2.2 125 MWe Class

For the 125 MWe class plant turbine, three major alternate integration power cycles were analyzed. These power cycle schemes are shown in Figure C-1 and discussed below.

- o Power Cycle Scheme A - The reference topping cycle was integrated with the Etiwanda Unit 1 turbine operating with a condenser pressure of 2.0 in. Hga. The turbine, with its high pressure feedwater heaters out of service, operates at a part load of 65 percent. By removing all the high pressure feedwater heaters above the deaerator, it was possible to integrate the complete waste heat from the MHD loop of the topping cycle into feedwater heating. The net plant output, including the 35.5 MWe gross output from the MHD system, is 91.1 MWe at a net plant efficiency of 35.1 percent. The same plant, with a condenser pressure of 2.5 in. Hga, has a net plant output of 89.9 MWe and a net plant efficiency of 34.6 percent. Discussion of the power cycle for the 2.0 in. Hga condenser appears in Section 4.3, Case 2A.
- o Power Cycle Scheme B - The Etiwanda Unit 1 turbine is integrated with the reference MHD topping cycle and the partially fired existing boiler. The turbine is operated at its full load of

125 MWe nominal, its steam requirements being supplied by both the MHD system and the partially fired existing boiler.

In the first scheme, Case 2B-1, the turbine was operated at full load with all of its extraction feedwater heaters in service. The feedwater exiting the last heater is at 427°F and 2,216 psia and, therefore, is not a suitable coolant to recover the waste heat from the MHD generator, hence, a separate cooling loop for the MHD generator is employed. Since the reference MHD topping cycle system cannot provide all of the turbine steam requirements, the partially fired existing boiler supplies the remainder. Part of the superheated steam is used for an auxiliary steam turbine which drives the compressor. The MHD steam system is used only to generate superheated steam, and the existing boiler supplies the remainder of the superheated steam and full reheat steam flow as required by the turbine. The net plant output for this integrated power cycle scheme at 2.0 in. Hga condenser pressure is 143.6 MWe at a net plant efficiency of 33.3 percent. At 2.5 in. Hga, the plant has a net output of 142.6 MWe at an overall efficiency of 33.1 percent. The discussion of results for a 2.0 in. Hga condenser pressure appears in Section 4.4, Case 2B-1.

The second arrangement which falls into the same power cycle, Scheme B, has the following modifications:

- The high pressure heaters above the deaerator of the turbine cycle are out of service during MHD operation, and, as a result, the feedwater entering the MHD system is relatively cooler and at a lower pressure than were they in service.
- All of the heat used for cooling the MHD loop is recovered and used for feedwater heating.

With this arrangement, the integrated power plant at 2.0 in. Hga condenser pressure has a net plant output of 144.9 MWe at an overall efficiency of 33.2 percent. At 2.5 in. Hga condenser pressure, the plant has a net plant output of 144.1 MWe at an overall efficiency of 33.0 percent. The discussion of this power cycle scheme for 2.0 in. Hga condenser pressure appears in Section 4.5, Case 2B-2.

- o Power Cycle Scheme C - In this scheme, an MHD system scaled-up 25 percent from the reference MHD system powers the Etiwanda Unit 1 bottoming cycle. The 25 percent scale-up provides the same plant power output. The gross output of the MHD generator for this larger system is 44.7 MWe.

In the first arrangement, all the feedwater heaters of the Etiwanda turbine cycle are in use. With an electric driven MHD air compressor, the MHD system generates as much of the superheated and reheat steam as possible to drive the Etiwanda turbine. The waste heat from the MHD generator is rejected to a separate coolant circuit, since the feedwater of the bottoming cycle exiting the last heater is too hot (423⁰F, 2216 psia) to be used as coolant. This power cycle arrangement, at 2.0 in. Hga condenser pressure, has a net plant output of 112.1 MWe at an overall efficiency of 34.6 percent. With the condenser at 2.5 in. Hga pressure, the net plant output is 110.9 MWe at an overall plant efficiency of 34.2 percent. The discussion for the 2.0 in. Hga condenser pressure is given in Section 4.4, Case 2C-1.

The second integrated power cycle arrangement eliminates the use of high pressure feedwater heaters during MHD operation. This permits the feedwater to be relatively colder (212⁰F) and lower in pressure (200 psia) when entering the MHD system. In this arrangement, all the waste heat from the MHD loop is integrated into feedwater heating. With an electric driven main compressor, the MHD system

supplies nearly 80 percent of the total steam requirements of the turbine. The MHD heat recovery boiler includes a reheat section in its design configuration. This integrated power cycle arrangement with its condenser at 2.0 in. Hga pressure, has a net plant output of 114.9 MWe operating at overall efficiency of 35.4 percent. With the condenser operating at 2.5 in. Hga, the integrated plant has a net output of 113.7 MWe at an overall efficiency of 35.1 percent. The discussion of this power cycle at 2.0 in. Hga condenser pressure appears in Section 4.7, Case 2C-2.

The third integrated power cycle arrangement which falls into this general power cycle scheme is the selected retrofit configuration. In this arrangement, the available energy from the MHD topping cycle is further enhanced by using a split low temperature economizer in the end of the topping cycle gas stream. By not using the high pressure feedwater heaters of the turbine cycle, the entry conditions of the feedwater to the MHD system permit complete recovery of the waste heat from the MHD loop. The net plant output for this arrangement at 2.0 in. Hga condenser pressure is 115.8 MWe with an overall efficiency of 35.7 percent. At 2.5 in. Hga, the plant has a net output of 114.9 MWe and an overall efficiency of 35.5 percent. The detailed discussion of this selected configuration is given in Section 4.8, Case 2C-3.

2.3 800 MWe Class

For the large, 800 MWe fossil power plants, other potential MHD retrofit power cycle schemes were considered. They are shown in Figure C-2 and described below:

- o Power Cycle Scheme A - The reference MHD system is integrated with a large, coal-fired, 2,535 psia/1,000^oF/1,000^oF steam plant. A separate feedwater loop for the MHD system keeps it isolated from

the main plant feedwater loop. MHD heat recovery produces superheated steam at 800°F which provides heat to the eighth high pressure feedwater heater in the main plant. The drain from the heater is returned to the MHD feedwater loop. A small portion of the MHD steam is used for powering an auxiliary steam turbine which drives the MHD air compressor. The exhaust steam from this turbine is discharged into an auxiliary condenser, the condensate from which is returned into the MHD feedwater loop. When the MHD system is not in service, the top feedwater heater will become an extraction feedwater heater of the main plant turbine cycle. A detailed heat balance for this arrangement was not performed.

The selected retrofit configuration, in general, fits into this category with the exception that the MHD system produces two levels of steam in the selected configuration. Also, in the selected configuration, the MHD steam supplies most of the power to the main plant boiler feed pump drive as well as replacing the eighth feedwater heater and providing power to the compressor drive.

- o Power Cycle Scheme B - Similar to that described in Scheme A, this arrangement has as many of the main plant auxiliaries as possible powered by the MHD generated steam. Superheated MHD steam supplies power to the induced draft fan drive of the main plant and to the turbine driven compressor. The exhausts from these auxiliary turbines are dumped into a low pressure steam header which, in turn, supplies steam to the main plant boiler feed pump drive. The exhaust from the boiler feed pump drive is discharged into an auxiliary condenser, the condensate from which is returned to the MHD feedwater loop. In the main plant, the turbine cycle is kept intact with all its extraction feedwater heaters in normal service.
- o Power Cycle Scheme C - This arrangement is a direct steam connection. A small portion of the main plant feedwater is diverted

from the condensate pump and used to cool the MHD loop. Subsequently, it is converted to superheated steam in the MHD heat recovery boiler. The MHD steam blends with most of the steam flow produced by the main plant boiler system. Full reheat steam requirement for the turbine is provided by the main boiler. The compressor of the topping cycle is steam driven; its exhaust cascades into the main condenser. In this scheme, if the MHD goes out of service, the bypass feedwater flow to the MHD system is secured, and the full flow passes through the main plant feedwater circuit and through the boiler system. A detailed heat balance was not performed for this power cycle.

3.0 OVERALL PERFORMANCE SUMMARY

The overall performance results obtained from the analysis of the MHD retrofit power cycles, summarized in Table C-1, are discussed below.

- o Reference Retrofit Power Cycle - Case 1A - This is a modified version of the AVCO/ETF reference MHD topping and bottoming cycles with a total thermal input of 260 MWt. The topping cycle, using 2,500°F preheated air from a separately fired, high temperature air heater, was integrated with a simple steam bottoming cycle. The high temperature air heater has an eight percent heat loss incorporated in its energy balance. This eight percent is the fraction of the total heat input to the air heater. With a gross output of 35.5 MWe for the MHD system, the power cycle has a net output of 79.5 MWe at an overall efficiency of 30.6 percent with a net heat rate of 11,146 Btu/kWh. The steam turbine cycle of this plant operates at 2.5 in. Hga condenser pressure.
- o Frank Bird Plant - Case 1C - The Frank Bird plant was integrated with the reference MHD topping cycle. With the high pressure heaters of the Frank Bird bottoming cycle out of service, all the

waste heat from the MHD loop is integrated into feedwater heating. A major part of the steam generated from the MHD heat recovery boiler is used for driving the main turbine unit; the remainder is used for the compressor drive. The net output from this integrated power cycle, at 2.5 in. Hga condenser pressure, is 80.3 MWe at an overall efficiency of 30.9 percent and a net heat rate of 11,035 Btu/kWh. For the existing oil-fired Frank Bird plant at the same condenser pressure, the net plant output is 65.1 MWe at an overall efficiency of 28.9 percent. The equivalent coal-fired plant is estimated to have a net plant output of 61.4 MWe at an overall efficiency of 26.6 percent.

The Frank Bird integrated power cycle is similar to the AVCO/ETF reference cycle with the exception that the Frank Bird plant has no deaerator. The overall plant performances are nearly identical.

o Etiwanda Unit 1 - 125 MWe Class

Turbine at Part Load - Case 2A - The Etiwanda steam turbine cycle was integrated with the 260 Mwt reference MHD topping cycle. Operating at about 60 percent part load, the turbine is powered by steam supplied from the MHD system. With the high pressure heaters of the turbine cycle not in use, waste heat from the MHD loop is used for feedwater heating. The compressor of the topping cycle is electric motor driven. The net plant output for this power cycle, at 2.0 in. Hga condenser pressure, is 91.1 MWe at an overall efficiency of 35.1 percent. At 2.5 in. Hga, the net plant output and the overall efficiency drop to 89.9 MWe and 34.6 percent, respectively.

Turbine at Full Load with Existing Boiler at Partial Firing - Case 2B-1 - The reference topping cycle was integrated with the Etiwanda Unit 1 turbine operated at full load. All extraction feedwater heaters are in use, and the condenser is at 2.0 in. Hga.

Since the feedwater entering the MHD system is at higher temperature and pressure, the waste heat from the MHD generator is rejected to a separate coolant circuit. In this power cycle arrangement, the MHD heat recovery boiler provides as much superheated steam as possible, while the existing boiler at partial firing rate supplies the remainder of the superheated steam and the full reheat steam to the turbine. The compressor is steam turbine driven. The net plant output for this integrated power cycle is 143.6 MWe at an overall efficiency of 33.3 percent. At 2.5 in. Hga, the net output and overall efficiency are 142.6 MWe and 33.1 percent, respectively.

Turbine at Full Load With Existing Boiler at Partial Firing -

Case 2B-2 - This power cycle integration is similar to that described in Case 2B-1 with the exception that in this power cycle the high pressure feedwater heaters are not in use, and the waste heat from the MHD generator is used for feedwater heating. The integrated plant, with the turbine exhausting into a condenser at 2.0 in. Hga pressure, has a net plant output of 144.9 MWe and an overall efficiency of 33.2 percent. For the condenser at 2.5 in. Hga, the net plant output and the overall efficiency drop to 144.1 MWe and 33.0 percent, respectively.

Scaled-Up MHD Topping Cycle With Turbine at Near Full Load -

Case 2C-1 - A 25 percent scale-up of the reference topping cycle was used for integrating with the Etiwanda Unit 1 steam bottoming cycle. The total heat input to this larger MHD topping cycle is 324 MWt which includes the eight percent heat loss from the high temperature air heater. The gross output from this topping cycle is 44.7 MWe. In this integration scheme, the full string of extraction feedwater heaters are in use and, hence, the feedwater is at a higher temperature and pressure entering the MHD system. Therefore, the waste heat from the MHD generator is rejected to a separate cooling circuit. Both the superheated and reheat steams produced by the MHD heat recovery boiler drive the turbine at nearly full load

conditions. This integrated power cycle, with the turbine exhausting into a condenser at 2.0 in. Hga pressure, has a net output of 112.1 MWe at an overall efficiency of 34.6 percent. The same plant at 2.5 in. Hga generates a net plant output of 110.9 MWe at an overall efficiency of 34.2 percent.

Scaled-Up MHD Topping Cycle With Turbine at Near Full Load -

Case 2C-2 - This integrated power cycle, using the 25 percent scaleup of the reference topping cycle, is similar to that described in Case 2C-1. The only difference is that, in this power cycle scheme, the high pressure feedwater heaters are not in use, and, as a result, the feedwater entering the MHD system is at a lower temperature and pressure. The waste heat from the MHD generator was integrated into feedwater heating. At 2.0 in. Hga condenser pressure, the net plant output is 114.9 MWe at an overall efficiency of 35.4 percent. The power cycle at 2.5 in. Hga pressure has a net plant output of 113.7 MWe at an overall efficiency of 35.1 percent.

Scaled-Up MHD Topping Cycle With Turbine at Near Full Load -

Case 2C-3 - This integrated power cycle scheme, with its high pressure feedwater heaters not in use, is similar to that described in Case 2C-2. The only difference is that the available heat from the topping cycle gas stream is enhanced by adopting a split, low temperature economizer at the back end of the topping cycle gas path which lowers the temperature of the hot gases entering the stack. The steam bottoming cycle, with the turbine exhausting into a condenser at 2.0 in. Hga, operates at about 80 percent of the design load. The net plant output is 115.8 MWe at an overall efficiency of 35.7 percent. The same plant at 2.5 in. Hga generates a net plant output of 115.0 MWe at an overall efficiency of 35.5 percent.

Oil-Fired - The Etiwanda Unit 1 plant, at present, is operating with an oil-fired boiler. The turbine cycle, with its full string of seven extraction feedwater heaters, has turbine steam conditions of

1,815 psia/1,000⁰F/1,000⁰F. With the condenser operating at 2.0 in. Hga pressure, the gross turbine output is 125.4 MWe. The auxiliary plant losses are estimated to be 8.3 MWe which agrees with actual operating data. The net plant output is 117.1 MWe at an overall efficiency of 35.1 percent. The evaluation of the overall efficiency for the plant takes into account that the oil-fired boiler operates at an efficiency of 88 percent. The same plant, with its turbine expanding into a condenser at 2.5 in. Hga, has a net plant output of 116.1 MWe and an overall efficiency of 34.8 percent.

Coal-Fired - In this analysis, Etiwanda Unit 1 is evaluated as a coal-fired unit. Compared to the oil-fired plants, the coal-fired plant has added auxiliary losses and reduced boiler efficiency. The auxiliary losses are estimated to be 11.36 MWe. The boiler is assumed to operate at an efficiency of 86 percent. With the condenser at 2.0 in. Hga, the plant has a net plant output of 114 MWe operating at overall efficiency of 33.4 percent. The same plant at 2.5 in. Hga has a net plant output of 113 MWe at an overall efficiency of 33.1 percent.

- o Topping Cycle Integration With Reference Fossil Plant of 800 MWe Size - Case 3C - The reference MHD topping cycle of 260 MWt was integrated with the 800 MWe reference coal-fired steam plant. The fossil plant is a 2,535 psia/1,000⁰F/1,000⁰F steam turbine cycle with its condenser designed to operate at 3.5 in. Hga pressure. The turbine cycle has seven extraction feedwater heaters and an eighth heater in which the feedwater heating is done by the steam supplied from the MHD system which produces two levels of steam, one at 800⁰F and the other at 1,000⁰F. The MHD and main plant feedwater loops are isolated from one another.

The 800°F steam from the MHD system is used to supply heat to the eighth feedwater heater, while the 1,000°F steam is used for the compressor drive. Also, most of the power for the main plant boiler feed pump drive is provided by the MHD steam system. This integrated power cycle arrangement has a net plant output of 795 MWe at an overall efficiency of 33.2 percent. The same integrated power cycle, at 2.5 in. Hga condenser pressure has a net output of 811 MWe at an overall efficiency of 33.7 percent. For comparison, the performance of the coal-fired reference fossil plant of 800 MWe nominal was evaluated. The 2,535 psia/1,000°F/1,000°F steam plant, with its low pressure turbines expanding into a condenser at 3.5 in. Hga, has a net plant output of 786 MWe at an overall efficiency of 33.6 percent (Case 3D).

Large Steam Turbine Plant, With MHD in Service, Designed for Full Load Operation - Case 3E - A large, four-flow, 700 MWe nominal, steam turbine (2,535 psia/1,000°F/1,000°F) was operated at full load condition in an integrated power cycle with the MHD in service. The integration scheme is the same as that described in Case 3C. The only difference is that the MHD steam system supplies about 50 percent of the power for the main plant boiler feed pump while the remainder comes from the main plant. With the MHD in full service, as the load on the main plant decreases, more of the main plant boiler feed pump power is provided by the MHD steam system. This integration power cycle scheme has a net plant output of 796 MWe and an overall efficiency of 33.5 percent at its design condenser pressure of 3.5 in. Hga.

With the MHD system out of service (Case 3F), the eighth feedwater heater simply becomes an extraction feedwater heater of the main plant turbine cycle. For the same throttle flow that had been used for the plant with the MHD system in service, the steam turbine plant would operate at an off-design point. With the condenser at

3.5 in. Hga, this plant would have a net output of 701 MWe at an overall efficiency of 33.6 percent. This means that the plant with the MHD system off operates at a net output of 701 MWe, and bringing MHD on-line increases the net output to 796 MWe. The plant, thus, has a peaking capability of 95 MWe.

4.0 DISCUSSION

4.1 Case 1A - Retrofit Reference Case - Modified AVCO/ETF Cycle

This case is a modified version of the 2,500⁰F air preheat AVCO/ETF topping and bottoming cycle with a total thermal input of 260 MWt. The AVCO/ETF combined cycle has been modeled to match the AVCO results as closely as possible. This AVCO/ETF-based cycle, with a total thermal input of 260 MWt, is the reference cycle for all retrofit power cycle studies. With a gross output of 35.5 MWe from the MHD generator, this reference cycle has a net output of 79.5 MWe at an overall efficiency of 30.6 percent.

The MHD cycle consists of a combustor, nozzle, MHD generator, diffuser, and heat recovery boiler system. The schematic of the topping cycle components and heat balance diagram of Case 1A are shown in Figure C-3. High temperature gases are produced in the combustor by burning pulverized Montana Rosebud coal together with 2,500⁰F preheated air at 95 percent stoichiometry. This primary air is supplied from a separate, oil-fired, high temperature air heater. Potassium seed is added at the combustor discharge to provide electrical conductivity. The high temperature gasses are expanded to high velocity in a nozzle and are passed through the magnetic field to generate direct current electric power. These gasses are decelerated in a diffuser and then enter the heat recovery boiler. The available heat from the gases produce steam for the bottoming cycle.

The steam bottoming cycle, which is part of the AVCO/ETF reference combined cycle, is also illustrated in Figure C-3. The MHD heat recovery steam generator produces all the steam requirements for the bottoming cycle. The majority of the steam supplied from the boiler drives the main steam turbine. A portion of the steam powers an auxiliary steam turbine which drives the main compressor. The main and auxiliary turbines discharge into a single condenser at 2.5 in. Hg pressure.

The bottoming cycle steam turbine, a 3,600 rpm, nonreheat, single flow, condensing turbine. The turbine is rated at 55 MWe and has a single extraction point. Steam from this extraction point is supplied to a deaerator, which is the only extraction feedwater heater. This same extraction point also supplies steam to some of the auxiliaries, such as the steam jet air ejector and the seed regeneration system.

The condensate from the main compressor passes through the steam jet air ejector and enters the MHD channel cooling passages at 112°F. After cooling the channel, the water is heated in a split, low temperature economizer at the end of the topping cycle heat recovery system. The heated water from the economizer is discharged into the direct contact deaerator where the feedwater is both deaerated and heated. This heated feedwater is raised to 1,620 psia by the boiler feed pump and sent to the high temperature economizer, where it cools the combustor, diffuser, and other topping cycle components. The feedwater is evaporated and superheated in the MHD heat recovery boiler to the 900°F turbine throttle conditions and shared by the main and compressor drive turbines.

This combined power cycle generates a net plant output of 79.5 MWe at an overall efficiency of 30.6 percent with a net heat rate of 11,146 Btu/kWh.

The total plant auxiliary power losses are 10.5 MWe^(*). This value is used in the analyses of all the retrofit power cycles, except where the scaled-up MHD topping cycle is used. The auxiliary topping cycle losses for the power cycles with the scaled-up system are increased to a value proportionate to the higher coal feed flow to the combustor.

The overall plant performance includes an eight percent heat loss in the high temperature air heater, which is a percentage of the total thermal input to the heater.

4.2 Case 1C - Reference Topping Cycle Frank Bird Turbine - Full Load

Description

The 260 MWt reference MHD topping cycle was retrofitted to a nominal 70 MWe power plant. The MHD gross output is 35.5 MWe and the steam turbine gross output is 56.1 MWe. The net plant output is 80.3 MWe.

The bottoming cycle chosen for the integration is the Frank Bird steam turbine which is a GE supplied, tandem compound, 3,600 rpm unit consisting of a single, nonreheat turbine. The turbine exhausts into a condenser at 2.5 in. Hga pressure. The throttle steam conditions to the turbine are 865 psia and 950°F, with the turbine rated at 70 MWe nominal output. Conventionally, this turbine cycle has a string of four extraction feedwater heaters in its flow path and is powered by the steam supplied from the oil- or gas-fired steam generator.

(*) AVCO Everett Research Laboratory, Inc.; Engineering Test Facility Conceptual Design, Final Report; prepared for U.S. Department of Energy, MHD Division; Report FE-2614-2 UC-90g; June 1978.

This plant is one of the retrofit study plants because it is in the general class of turbine cycles that could be fully powered by the 260 Mwt reference MHD topping cycle.

The feedwater from the low pressure feedwater heater enters the MHD heat recovery boiler system and exits as superheated steam at turbine throttle conditions. The existing boiler is not in operation. Most of the steam generated from the MHD system is utilized for driving the plant turbine while a portion (16 percent) of the total main steam is used for powering an auxiliary turbine for the air compressor drive. The exhaust steams from the main and auxiliary turbines are condensed and returned into the feedwater loop; only the two low pressure heaters are in service. The high pressure heaters were turned off in order to maintain the feedwater entering the MHD system at a lower temperature (239⁰F) and, thus, recover most of the available waste heat from the MHD system. The actual flow path of the feedwater through the MHD system is as follows. The feedwater from the low pressure heater, pressurized to 200 psia, passes through the low temperature economizer and enters the MHD channel as coolant at 266⁰F. The feedwater, raised to full pressure (1,194 psia) by the boiler feed pump, passes through the high temperature economizer, combustor, and diffuser. The coolant feedwater from the diffuser is circulated through the remaining components of the heat recovery boiler, such as the primary and secondary radiant furnaces, convective evaporative sections, and superheater sections.

In this bottoming cycle, the only extraction feedwater heaters are the low pressure heaters operating at 9.5 and 26.5 psia. If the high pressure heaters were also operational, the feedwater exiting the last high pressure heater would be too hot (350⁰F), thus derating the economizer to maintain a realistic temperature approach and recovering the generator waste heat. The feedwater from the last low pressure

heater, at 200 psia, enters the low temperature split economizer (4.5 MWt capacity) at 239°F. This allows an approach of 36°F between the stack gases leaving the low temperature economizer and the feedwater entering it. The feedwater enters the MHD channel as a coolant at 266°F and about 200 psia. For these entering conditions, steaming will not occur within the channel walls. The feedwater from the MHD channel, increased to 1,194 psia by the boiler feed pump, enters the high temperature split economizer (18.5 MWt capacity) at 338°F. This allows an approach of 42°F between the gas leaving the economizer (380°F) and the feedwater entering. After recovering the heat in the high temperature economizer, the feedwater, still at the boiler feed pump pressure (except for the frictional losses), enters the combustor and diffuser as a coolant. The feedwater will remain subcooled in the entire combustor (or burner) and in most of the diffuser (near the tail end of the diffuser, slight steaming with a quality of less than four percent may occur). The feedwater enters the primary and secondary radiant furnaces and the convective sections of the heat recovery boiler. The available heat in the gas stream of the heat recovery boiler goes into the production of superheated steam at 865 psia, 900°F. The drop in pressure from the boiler feed pump discharge pressure is attributable to the pressure drop in the various components of the boiler.

About 16 percent of the total superheated steam is used for an auxiliary turbine to drive the air compressor (11.3 MWe) of the topping cycle. The exhaust from the auxiliary turbine is directly cascaded into the main plant condenser at 2.5 in. Hga pressure. The remainder of the superheated steam (84 percent) drives the main plant turbine to produce a turbine gross electrical output of 56.1 MWe. If all the main steam were used to drive the main turbine, the turbine gross output would exceed the maximum capacity (66 MWe) and, thus, a turbine drive was chosen instead of electric drive for the compressor.

The plant net output, including the MHD power, for this integrated power cycle is 80 MWe. The overall plant efficiency is 30.9 percent with a net heat rate of 11,035 Btu/kWh. The bottoming cycle has a conversion efficiency of 33.4 percent. The reduction in efficiency from the bottoming cycle to the overall plant value is due to the plant auxiliary losses, the boiler inefficiency, and an eight percent heat loss in the separately fired, high temperature air heater of the topping cycle. However, a modern reheat turbine cycle will usually have a value of about 42 percent for its conversion efficiency. Since the Frank Bird plant has a nonreheat and relatively low pressure (865 psia, 900°F) turbine, the bottoming cycle conversion efficiency is lower.

For ease of reference and comparison, the Frank Bird turbine is considered to be fully powered by a coal-fired boiler. The turbine cycle is fully intact with all its extraction feedwater heaters in service, and its throttle steam conditions are 865 psia and 900°F with the turbine exhausting into a condenser at 2.5 in. Hg pressure. At a steam flow close to design, the turbine gross output is 68.2 MWe. Assuming a boiler efficiency of 86 percent and with estimated auxiliary plant losses of 6.8 MWe, the overall net plant efficiency is 26.6 percent, and the plant output is 61.4 MWe. The overall plant efficiency of the integrated power cycle is higher by 4.3 percentage points than that of the coal-fired plant.

Further comparison is made with the performance of the Frank Bird plant and its existing oil-fired boiler. For the same turbine conditions as specified in the coal-fired plant analysis, the turbine gross output is 68.2 MWe. The net plant output is 65.1 MWe with auxiliary losses at 3.1 MWe. Since the oil-fired boiler is more efficient (88 percent) and has lower auxiliary plant losses, the overall plant efficiency increases to a value of 28.9 percent compared to 26.6 percent for the coal-fired boiler. The overall plant efficiency of the integrated

power cycle is significantly higher by 2.0 percentage points when compared to the existing plant performance.

Thus, retrofitting the Frank Bird plant increases the net plant output by 15 MWe, and the overall plant efficiency improves at least 2.0 percentage points.

There are several notable differences between the Frank Bird retrofit power cycle and the AVCO/ETF reference cycle. The Frank Bird has two low pressure extraction feedwater heaters and no deaerator, and the AVCO/ETF reference cycle (Case 1A) has a deaerator which is the only extraction feedwater heater. The bottoming cycles of both Frank Bird and the AVCO/ETF have nonreheat steam turbines with 865 psia/900°F throttle conditions, respectively. The air compressor in either cycle is a steam driven unit. The feedwater in the AVCO/ETF reference cycle enters the MHD generator and goes to the low temperature economizer, whereas in the Frank Bird integration, it was more appropriate to send the feedwater first to the split low temperature economizer. The main condenser of either cycle is at 2.5 in. Hga pressure. To conclude, the AVCO/ETF reference cycle has a 32.9 percent efficiency for its bottoming cycle conversion compared to 33.4 percent for the Frank Bird turbine without its high pressure heaters. The net plant output from the AVCO/ETF reference cycle is 79.5 MWe at an overall plant efficiency of 30.6 percent, which are nearly identical to those for the Frank Bird integrated power cycle.

4.3 Case 2A - Reference Topping Cycle Etiwanda Turbine - Part Load, No High Pressure Feedwater Heaters

For this case, the reference 260 Mwt topping cycle was integrated with a 125 MWe class station. Etiwanda Unit 1 was chosen as a representative of this class. The MHD generator of the topping cycle generates a gross output of 35.5 MWe. The bottoming cycle, with the

condenser at 2.0 in. Hga pressure, has a gross output of 78.6 MWe. The overall net plant output is 91.1 MWe.

The Etiwanda Unit 1 turbine is a GE supplied, tandem compound, 3,600 rpm unit consisting of high pressure, reheat, and low pressure turbines expanding into a condenser at 2.0 in. Hga. The 125 MWe nominal turbine/generator set has main steam conditions of 1,815 psia/1,000°F to its high pressure turbine and reheat steam of 1,000°F to its reheat turbine. Conventionally, the turbine cycle, with its six extraction feedwater heaters (one deaerator, two intermediate pressure, and two high pressure heaters) and a gland steam condenser, is operated by the steam supplied from an oil-fired boiler. In this retrofit power cycle scheme, only the two low pressure feedwater heaters and the deaerator are operational; all the high pressure heaters above the deaerator are out of service. The feedwater from the deaerator goes directly to the MHD system as coolant. The available heat from the MHD system goes into producing as much of the superheat and reheat steam as possible.

In this scheme, complete integration of the topping cycle is possible by recovering waste heat from the cooling of the combustor, MHD generator, and diffuser. Generator design dictates that coolant pressure be approximately 200 psia and that temperatures remain low enough to keep the coolant in the subcooled region. To accommodate these design restrictions, the top four high pressure feedwater heaters of the bottoming cycle were taken out of operation, leaving only the deaerator, a low pressure heater, and the gland steam condenser in service. The feedwater conditions out of the deaerator are 200 psia and 202°F. Passing this feedwater through the generator and pumping to full throttle pressure, the feedwater is at 290°F/2,185 psia as it enters the economizer. Maintaining a 40°F approach with the exhaust gas on the cool side of the economizer, the feedwater was able to absorb 20.6 MWt. Continuing through the MHD loop, the feedwater (coolant) remains subcooled. There is no evaporation until the

feedwater enters the primary radiant furnace; two more heat exchangers complete the evaporation, and a series of two superheaters brings the feedwater to high pressure steam turbine throttle conditions of 1,815 psia/1,000°F. To complete the MHD waste heat recovery, the high pressure turbine exhaust steam is reheated to 1,000°F.

Etiwanda is capable of supplying more feedwater than the MHD topping cycle can use. As a result, there are two options for cycle design: the existing boiler can have partial auxiliary firing to let the bottoming cycle run at full steam flow, or the cycle can be run at part load. For this case, the latter was chosen, and the steam cycle is run at approximately 65 percent load.

With the existing boiler and the top four feedwater heaters out of service, the remaining bottoming cycle consists of a tandem compound, triple flow, single reheat, extraction turbine exhausting into a condenser maintained at 2.0 in. Hga pressure. This condensate is circulated to two steam extraction feedwater heaters and a steam extraction deaerator for feedwater heating and deaeration, and returned to the topping cycle waste heat recovery system.

This integration scheme has an overall plant efficiency of 35.1 percent, developing 91.1 MWe with a net heat rate of 9,727 Btu/kWh. To facilitate comparisons with other retrofit power cycle schemes, this case was rerun with a 2.5 in. Hga condenser back pressure. The net output was reduced to 89.9 MWe operating at an overall efficiency of 34.6 percent for a net heat rate of 9,856 Btu/kWh. This overall plant efficiency is significantly higher than for the AVCO/ETF reference cycle (Case 1A) at 30.6 percent. This can be attributed to higher steam pressure, 1,815 psia in the Etiwanda turbine versus 1,265 psia in the AVCO/ETF reference cycle. Also, the Etiwanda turbine cycle has a reheat turbine, whereas the AVCO/ETF reference cycle has a nonreheat turbine.

4.4 Case 2B-1 - Reference Topping Cycle Etiwanda Turbine - Full Load, Existing Boiler - Partially Fired, All Feedwater Heaters In Service

For this case, the reference MHD cycle is used in conjunction with partial firing of the existing boiler to generate enough steam to operate the Etiwanda Unit 1 turbine cycle at plant design power output (125 MWe).

With the complete string of extraction feedwater heaters in service, part of the feedwater from the last high pressure heater is circulated through the MHD system and converted into superheated main steam. The remainder of the superheated main and the full reheat steam flow requirements for the Etiwanda turbine are supplemented by the existing boiler at partial firing.

In this scheme, all feedwater heaters are operational, and the existing boiler is used to supply part of the main steam and full reheat steam to the turbine. Since the full feedwater string is operational, the feedwater exiting the string is at 2,216 psia and 445°F. About two-thirds of the total feedwater flow at these conditions is piped to the MHD system for heat recovery, while the remaining flow passes through the existing boiler. These conditions exceed MHD generator coolant loop design limitations and, therefore, prohibit recovering the waste heat from this component. As a result, the generator waste heat is rejected to a cooling tower in a separate loop. With the exception of the economizer, the other components in the MHD waste heat recovery system are not affected by the feedwater heater exit temperature and pressure levels, and their full waste heat potentials are utilized. The feedwater enters the economizer section at 445°F, allowing a temperature difference of 40°F between the hot gases leaving the economizer and the feedwater entering it. Also, because of the high temperature (485°F) of the gases leaving the economizer, their

available heating capacity is reduced to a value of 13.9 Mwt compared to a value of 23 Mwt in the AVCO/ETF reference cycle (Case 1A).

For this case, the main compressor of the MHD topping cycle is driven by an auxiliary steam turbine using part of the main steam. The exhaust from this auxiliary steam turbine is piped into the main steam plant condenser. The condensate passes through the feedwater heater string. About two-thirds of the feedwater flow is returned to the MHD system as a coolant, while the remaining third is returned to the existing boiler. The superheated steam produced by the MHD heat recovery boiler blends with the main steam supplied from the existing boiler to make up the full throttle flow to the Etiwanda Unit 1 turbine and auxiliary turbine. The exhaust from the high pressure turbine of the main unit is brought to the reheat steam conditions in the existing boiler.

The net plant output of the integrated power cycle with its condenser maintained at 2.0 in. Hga pressure is 143.6 MWe, yielding an overall efficiency of 33.3 percent and heat rate of 10,243 Btu/kWh. To facilitate comparison with other cycles, the performance of the power cycle was re-evaluated with 2.5 in. Hga. The net power output from the plant is reduced by one MWe to 142.6, operating at an overall efficiency of 33.1 percent with a net heat rate of 10,315 Btu/kWh.

The steam bottoming cycle, with a condenser pressure of 2.0 in. Hga, has a conversion efficiency of 41.5 percent. The reduction of efficiency from 41.5 percent to 33.3 percent is due to the plant auxiliary losses and the inefficiency of the partially fired, existing boiler. Considerable modification to the existing boiler may be required to allow for one-third flow through the economizer, waterwalls, and superheater and full flow through the reheater.

4.5 Case 2B-2 - Reference Topping Cycle Etiwanda Turbine
Full Load, Existing Boiler - Partially Fired, No High Pressure
Feedwater Heaters in Service

The reference MHD topping cycle is integrated with the Etiwanda Unit 1 steam plant with its high pressure feedwater heaters out of service. This integrated power cycle scheme is very similar to that described in Case 2B-1 with the following exceptions:

- o The heat rejected in cooling the MHD generator is integrated into feedwater heating.
- o The high pressure feedwater heaters are taken out of service.
- o There is increased heating capacity in the economizer as a result of colder feedwater entering the economizer section.

Discussion

For this cycle, the economizer gas content is more fully used in the economizer than in Case 2B-1, since the feedwater temperature is lower with the high pressure feedwater heaters out of service. However, due to this lower temperature, the existing boiler must add more heat to its feedwater to reach the 1,815 psia/1,000⁰F steam throttle conditions. This is a penalty on the conversion efficiency of the bottoming cycle.

With the extra steam flow through the turbine caused by removal of extraction requirements of high pressure feedwater heaters, power output and the low pressure turbine loading would be increased at constant feedwater flow. To alleviate this problem, throttle flow was

reduced to achieve the same level of bottoming cycle power as in Case 2B-1 (125 MWe). This power output was attained at a steam flow rate approximately 100,000 lb/hr lower than in Case 2B-1 (725,000 lb/hr vs. 832,800 lb/hr).

With the condenser at 2.0 in. Hga, the net plant output is 144.9 MWe at an overall efficiency of 33.2 percent and a net heat rate of 10,283 Btu/kWh. The bottoming cycle conversion efficiency for the steam cycle is 39.2 percent, reflecting the absence of its high pressure extraction feedwater heaters. The drop in efficiency from the bottoming cycle conversion value to the overall plant value is due to auxiliary plant losses, stack losses, and the inefficiency of the partially fired existing boiler.

The same integrated power cycle, with its condenser at 2.5 in. Hga, has a net plant output of 144.1 MWe operating at an overall efficiency of 33.0 percent with a net heat rate of 10,340 Btu/kWh.

4.6 Case 2C-1 - Scale-Up of Reference Topping Cycle, Etiwanda Turbine - Part Load, All Feedwater Heaters In Service

In this integrated power cycle arrangement, a scaled-up MHD system, 25 percent larger than the reference topping cycle, powers the Etiwanda Unit 1 steam bottoming cycle with all its extraction feedwater heaters in service. The 25 percent scale-up was chosen using engineering judgement. This larger topping cycle, with an electric motor driven compressor, can power the steam plant at nearly 75 percent load without firing the existing oil-fired boiler. The total thermal input to the larger topping cycle is 324 MWt. The gross output of the MHD generator for this system is 44.7 MWe. The net plant output, with its condenser at 2.0 in. Hga pressure, is 112.1 MWe at an overall efficiency of 34.6 percent.

The steam turbine of Etiwanda Unit 1 plant is a GE supplied, tandem compound, 3,600 rpm unit consisting of high pressure, reheat, intermediate pressure, and low pressure turbines. The triple flow, low pressure turbines exhaust into a condenser operating at 2.0 in. Hga. The turbine is designed to operate at condenser back pressures ranging from 2 to 3.5 in. Hga. The throttle steam conditions are 1,815 psia and 1,000°F at the high pressure turbine and 1,000°F at the reheat turbine. With its complete string of extraction feedwater heaters in service, the exiting feedwater from the last high pressure heater is at 2,216 psia and 423°F.

Since the feedwater from the last heater is already at high temperature and pressure, it can not be the coolant for the MHD generator. Therefore, a separate cooling circuit is employed for rejecting the waste heat from the MHD generator. The economizer had to be derated to a heating capacity of 17.7 MWt because the temperature of the feedwater entering the economizer is high. After passing through the economizer section, the high pressure feedwater is circulated through the combustor and diffuser sections of the MHD loop. From the diffuser, estimated to be at a slightly subcooled condition, the feedwater enters the primary and secondary radiant furnaces and other components of the heat recovery boiler for subsequent conversion to steam. The superheated and reheat steams supplied from the MHD heat recovery boiler drive the Etiwanda Unit 1 turbine.

This integrated power cycle arrangement, with its condenser at 2.0 in. Hga, has a net output of 112.1 MWe at an overall efficiency of 34.6 percent. The corresponding net heat rate for the plant is 9,871 Btu/kWh. The same power plant, for a condenser pressure of 2.5 in. Hga, has a net plant output of 110.9 MWe at an overall efficiency of 34.2 percent with a net heat rate of 9,978 Btu/kWh.

The conversion efficiency for the steam bottoming cycle is 41.5 percent, with all its extraction feedwater heaters in service and condenser at 2.0 in. Hga pressure. The 7.3 percentage point drop in efficiency from the bottoming cycle to the overall plant value is due to the auxiliary plant losses, loss of coolant heat from the MHD generator, an eight percent heat loss in air preheater, and boiler inefficiency caused by the high stack gas temperature. The auxiliary plant losses for the larger size topping cycle is 13.1 MWe, estimated by increasing the reference cycle value in proportion to the higher coal feed flow to the combustor.

4.7 Case 2C-2 - Scale-up of Reference Topping Cycle, Etiwanda Turbine - Part Load, No High Pressure Feedwater Heaters

The larger MHD topping cycle, scaled-up 25 percent from the reference cycle, is integrated with the Etiwanda Unit 1 steam plant with its high pressure feedwater heaters out of service. This integrated power cycle scheme is very similar to that described in Case 2C-1 with the following exceptions:

- o The waste heat from the MHD generator is integrated into feedwater heating.
- o There is increased heating capacity in the economizer as a result of the colder feedwater entering the economizer section.

In this integrated power cycle scheme, the feedwater at 212⁰F, pumped to 200 psia, is circulated through the MHD generator cooling passages. From the MHD generator, the feedwater enters the economizer at 2,206 psia and 298⁰F. The hot gases leaving the economizer are at 338⁰F, allowing a difference of 40⁰F from the entering feedwater. Due to the lower stack gas temperature (373⁰F), the economizer heating capacity is increased to 27.3 MWt compared to the 17.7 MWt in the Case 2C-1 configuration. After flowing through the economizer, the feedwater is circulated as coolant through the combustor and the diffuser (where it

exits 36⁰F cooler than saturation temperature) before entering the radiant, evaporative, convective, and superheat sections of the MHD heat recovery boiler. The superheated and the reheat steams supplied by the heat recovery boiler can run the steam bottoming turbine cycle at about 80 percent load. This integrated power cycle, with its condenser at 2.0 in. Hga pressure, has a net plant output of 114.9 MWe at an overall efficiency of 35.4 percent. The corresponding net heat rate for the plant is 9,630 Btu/kWh. The same plant, for a condenser pressure of 2.5 in. Hga, has a net plant output of 113.7 MWe at an overall efficiency of 35.1 percent with a net heat rate of 9,721 Btu/kWh.

Although the bottoming cycle conversion efficiency was penalized by not using the high pressure extraction feedwater heaters, the overall power plant has a performance improvement over Case 2C-1. This is because of complete recovery of waste heat from the MHD loop as well as increased heating capacity in the economizer.

4.8 Case 2C-3 - Scale-up of Reference Topping Cycle, Etiwanda Turbine - Part Load, No High Pressure Feedwater Heaters, Split Economizers

This cycle is the same as Case 2C-2 except that the economizer is split into two sections (low and high temperature sections) to more fully use the heat content in the gas stream of the topping cycle exhaust. By sending feedwater to the low temperature section of the economizer instead of the MHD generator, an additional 5.3 MWt is extracted at the back end of the topping cycle. This reduces the stack gas to 275⁰F and makes full use of exhaust waste heat potential without sacrificing heat recovery in any of the other components at a condenser pressure of 2.5 in. Hga. The MHD gross output is 44.7 MWe with the steam turbine adding another 99.3 MWe. Net plant output is 115.0 MWe.

The available energy from the large MHD topping cycle system is capable of producing nearly 80 percent of the total steam requirements for the bottoming cycle. In this retrofit power cycle scheme, the existing boiler and all of the high pressure feedwater heaters above the deaerator are not in operation. The feedwater from the deaerator, pumped to 200 psia, directly enters the MHD heat recovery system at 212°F. The actual flow path of the feedwater in the MHD system is as follows.

The feedwater at 200 psia and 212°F enters the low temperature split economizer (5.3 MWt heating capacity). The temperature approach between the entering feedwater and the stack gases leaving the low temperature economizer is maintained at 63°F. The feedwater, after passing through the MHD generator coolant passages, is pumped to 2,205 psia and 324°F before entering the high temperature economizer. The hot exhaust gases leaving the high temperature economizer are at a temperature of 372°F which ensures a difference of 48°F from the entering feedwater. The feedwater is circulated through the combustor and diffuser walls as a coolant to recover the waste heat. The coolant from the diffuser enters the remaining components of the MHD heat recovery boiler in a slightly subcooled condition.

The superheated main steam at 1,815 psia and 1,000°F from the superheater section of the heat recovery boiler goes to the high pressure turbine. The steam exhausted from the high pressure turbine, after being reheated to 1,000°F in the reheater section of the MHD boiler, is supplied to the intermediate pressure reheat turbine. The exhaust steam from the intermediate pressure turbine is fed into a low pressure turbine for further expansion to the condenser back pressure. The condensate, along with the cascaded drains from the low pressure extraction heater, is returned to the feedwater circuit. The last heater in the bottoming cycle before the feedwater enters the MHD system is the deaerator, where the dissolved gases are removed.

The feedwater string of the bottoming cycle has only two low pressure extraction heaters operating at 4.60 and 4.71 psia and the deaerator operating at 14.70 psia. The remaining extraction heaters (two intermediate and the two high pressure heaters) are not in operation in this power cycle concept during MHD operation. The extraction steams to these high pressure heaters, which would normally be used for feedwater regenerative heating, are now expanded through the turbine to produce more power. The high pressure feedwater heaters were eliminated in order to maintain a lower temperature for the feedwater entering the economizer and, thus, ensure a full heating capacity in the economizing section. Also, since the feedwater out of the low temperature economizer is at a low temperature and pressure (244°F, 200 psia), waste heat from cooling the MHD generator is recovered. If, on the other hand, the full feedwater heater string was in operation, the feedwater exiting the last heater would be at 450°F and 2,200 psia. These would be unacceptable entry conditions for coolant in the MHD channel and would result in rejection of the channel heat to a separate loop. Also, the stack gases that leave the economizer would have to be near 500°F, resulting in a less efficient boiler.

The plant net output for this retrofit integration scheme with 2.5 in. Hga condenser pressure, including the MHD power, is 115.0 MWe. The overall plant efficiency is 35.5 percent, with the bottoming cycle having a conversion efficiency of 39.2 percent. If all the high pressure heaters of the heater string were to be in service, the bottoming cycle conversion efficiency would be 41.5 percent. The two point difference in conversion efficiency is due to elimination of all the high pressure feedwater heaters. The drop in efficiency from the value of the bottoming cycle (39.2 percent) to the value of the overall plant (35.5 percent) is due to plant auxiliary losses, boiler

inefficiency, and an eight percent heat loss in the separately fired, high temperature air heater of the topping cycle.

The retrofit power cycle scheme discussed above was also analyzed for a condenser pressure of 2.0 in. Hga, since the turbine/generator set of Etiwanda Unit 1 is normally operated at that pressure. As expected, the net plant power increased by about one MWe to 115.8 MWe. Since the auxiliaries of the plant and the total heat supplied to the plant remain the same, the effect of dropping the back pressure by 0.5 in. Hga is an overall plant efficiency of 35.7 percent, an increase of 0.2 percentage points.

Comparison Stand-Alone Plants - 125 MWe Class

For comparison, the performance of the Etiwanda plant was evaluated 1) as if the plant were powered entirely by coal, and 2) in its actual oil-fired configuration. The analysis for a coal-fired class plant was performed with the assumption that the turbine cycle operates with its full string of extraction feedwater heaters. The throttle steam conditions to the high pressure turbine are at 1,815 psia and 1,000°F, and the steam to the reheat turbine enters at 1,000°F. The low pressure turbine exhausts its steam into a condenser at 2.5 in. Hga pressure. The plant is operating at its rated capacity. At a steam flow close to design, the steam turbine gross output is 124.4 MWe. The coal-fired plant, with an estimated auxiliary power loss of 11.4 MWe and an assumed efficiency of 86 percent for its boiler, has a net plant output of 113 MWe at an overall plant efficiency of 33.1 percent. The selected retrofit power cycle Case 2C-3 has a higher overall plant efficiency, 35.4 percent.

The MHD retrofit power cycle has a 2.0 MWe increase in net plant output and a 2.3 percentage point improvement in overall plant efficiency over a coal-fired Etiwanda plant.

A similar analysis was made for Etiwanda Unit 1 with its existing oil-fired boiler. For identical turbine throttle and 2.5 in. Hga condenser conditions, the turbine gross output is 124.4 MWe. The plant operating auxiliary losses are 8.3 MWe. Since it is an oil-fired unit, the boiler operates at a higher efficiency of 88 percent. The plant, therefore, performs with a net output of 116 MWe operating at an overall plant efficiency of 34.8 percent. This compares with the value of 35.4 percent estimated for the selected retrofitted power cycle.

4.9 Case 3C - Reference Topping Cycle, 800 MWe Subcritical Steam Plant, MHD Heat Recovery Supplies Top Feedwater Heater

The reference 260 MWt MHD retrofit topping cycle was integrated with the Gilbert/Commonwealth reference 2,535 psia/1,000⁰F/1,000⁰F coal-fired steam turbine power plant of 800 MWe nominal capacity. The condenser system of the main plant is designed to operate at 3.5 in. Hga. For this case, the MHD system and the main steam bottoming plant have their own independent feedwater loops. The steam raised by the MHD heat recovery boiler is used as a heat source to replace the top high pressure feedwater of the main plant as well as to supply a major part of the main plant boiler feed pump power. This selected power cycle has a net plant output of 795 MWe operating at a net plant efficiency of 33.2 percent.

The feedwater circuit of the MHD topping cycle cools the MHD components, recovers as much of the available waste heat as possible from the MHD heat recovery boiler, and converts it into useful work. The MHD feedwater system is self-contained with its own condenser designed to operate at 3.5 in. Hga, a deaerator operating at 115 psia, and associated pumps. The condensate is pumped from the condenser to the MHD system to produce two levels of steam, one at 1,150 psia, 800⁰F and the other at 1,000 psia and 1,000⁰F. The 800⁰F steam is used as a heat source for the last high pressure feedwater heater of the main

plant. The drain from this heater is cascaded into a flash tank which generates low pressure steam and feeds into a steam header at 115 psia. The major portion of the hot drain from the flash tank is piped into the deaerator, while a small portion is returned to the condenser. The 1,000°F steam from the MHD is used to drive the MHD compressor turbine which exhausts into the 115 psia steam header. This header steam supplies most of the main plant boiler feed pump power and the power for deaerating the MHD feedwater. The remainder of the main plant boiler feed pump power is supplied by the main plant steam extracted from the crossover point. The exhaust from the boiler feed pump turbine discharges into a condenser at 3.5 in. Hga pressure. The condensate is returned to the MHD feedwater loop for heat recovery.

The reference steam turbine plant is an 800 MWe nominal, 2,535 psia/1,000°F/1,000°F unit with a tandem compound, four-flow, intermediate-flow pressure turbine. Steam to the turbine is supplied from a pulverized coal-fired boiler. The boiler feedwater is heated by a string of seven extraction feedwater heaters and an eighth special heater, the heat source of which is provided from the MHD system steam. This eighth special heater is a high pressure heater; of the other seven heaters, four are low pressure heaters, one is a deaerator, and the other two are high pressure heaters. To pressurize the feedwater, steam turbine driven boiler feed pumps are employed. Most of the power (90 percent) to these pumps is supplied by the MHD system steam; the remainder of the required pump power is provided by steam extraction from the main steam plant crossover point between the intermediate and low pressure turbines. This system of feedwater heaters and boiler feed pumps raises the steam turbine condensate from 3.5 in. Hga and 121°F to 3,138 psia and 542°F before the condensate reenters the boiler for final heating, evaporation, and superheating to the steam turbine throttle conditions.

At full load, the MHD system supplies power to its compressor and main plant boiler feed pump and provides heat to the main plant feedwater via the eighth special heater. To provide this heat and power to the main plant, the topping cycle has its own steam bottoming cycle which recovers the channel heat by circulating condensate at 121°F and 100 psia through the channel cooling system. The channel coolant, pressurized to 250 psia, enters the low temperature economizer at 253°F, which yields a 22°F difference from the stack gases leaving the economizer. The heated water from the economizer, together with the drain from the flash tank, is deaerated at 115 psia. The drain from the deaerator, pumped to 1,450 psia, circulates through the high temperature economizer, combustor, and diffuser. In the MHD heat recovery boiler, the feedwater from the diffuser exit is evaporated and superheated to the throttle conditions required for the steam turbine drives of the MHD compressor and main plant boiler feed pump.

For the retrofit, the main plant bottoming cycle chosen is a Gilbert/Commonwealth reference fossil plant of 800 MWe. In order to understand the results of the retrofit power cycle, the base plant operation will be discussed with and without the top heater in service.

The base plant, a 2,535 psia/1,000°F/1,000°F cycle, is an 800 MWe unit with a tandem compound, four-flow turbine and eight extraction feedwater heaters (Case 3D). When run at full load, five percent over pressure, and valves wide open, the low pressure turbines will be back-end loaded at 95 percent. The throttle flow for these conditions is 6,387,657 lbm/hr. If this machine, at full load conditions, were to lose the top feedwater heater, the flow through the turbine would be increased and back-end loading problems would result. To avoid this, the throttle flow is reduced such that the back-end loading will remain at the design value; i.e., the flow through the back-end of the turbine is maintained constant. Alternately, a larger, six-flow turbine could

handle the excess flow, if more frequent on/off switching of the top heater is expected in the plant operation.

In the retrofit power cycle, the operation of the eighth top heater from the MHD steam source is equivalent to the situation discussed above for the base plant with its top heater out of service. Furthermore, in the retrofit, the main plant boiler feed pump is powered by the MHD steam source. As a result, if the throttle steam flow in the retrofit cycle is maintained at the same value as that in the base plant, more flow is available to go through the turbine, leading to the back-end loading problem. Therefore, the throttle flow is decreased to keep the same back-end loading as in the base plant. The gross steam power from the retrofit power cycle turbine is 826.8 MWe, which is close to the nominal value of 800 MWe. Additionally, the decrease in throttle flow reduces the fuel input to the boiler. This retrofit power cycle scheme has a net plant output of 795 MWe at an overall net plant efficiency of 33.2 percent with a net heat rate of 10,279 Btu/kWh. By comparison, the stand-alone, coal-fired, base plant without MHD in operation has a net plant output of 786 MWe with an overall net plant efficiency of 33.6 percent at a net heat rate of 10,163 Btu/kWh.

The 800 MWe reference fossil plant has a four-flow turbine operating at a design flow of 6,387,657 lbm/hr without MHD in service. For this configuration, the turbine, with a back-end loading of 95 percent, is generating a net output of 849.5 MWe. For the same throttle flow when MHD is in service, the absence of the extraction steam to the top heater and to the boiler feed pump drive increases the flow through the turbine and, hence, increases the back-end loading on the turbine. Therefore, to maintain the design back-end loading, the throttle flow is reduced to 5,694,260 lbm/hr. The net turbine output for this integrated plant is 827 MWe.

Peaking Capability and Part Load Considerations

The selected retrofit configuration required a reduction in high pressure turbine flow to assure proper loading of the lower pressure turbine sections when the MHD system was in operation. There is an alternate, feasible method which takes advantage of the additional steam flow available when the extraction requirement for feedwater is replaced by the MHD generated steam. This method requires a turbine with increased low pressure turbine capacity, either larger rear stage buckets or additional low pressure turbine sections. For the reference plant turbine size, this would require a change from a four-flow to a six-flow low pressure turbine section arrangement since this four-flow turbine already has the largest bucket size available. With this rearrangement, the main plant steam turbine could be designed to handle full high pressure turbine throttle flow with the topping cycle in service. Additional power generation capacity with MHD in operation is traded for the additional capital investment required for that capacity.

Table C-2 shows the major differences in the turbine parameters for three cycles studied: 1) the 800 MWe base plant without MHD in service, 2) the 900 MWe plant with MHD in service, and 3) the 800 MWe base plant with MHD in service.

The 900 MWe plant is derived by passing the 6,387,657 lb m/hr throttle flow of the reference plant with MHD retrofit through a six-flow turbine. This configuration (Case 3E) accounts for the extra steam to the turbine back-end and sizes the turbine to assure that stress loading with the top feedwater heater out of service will be acceptable. When the MHD system is out of service and the top feedwater heater is extracting steam for its work, the back-end of the steam turbine will be passing less than design flow, thus, avoiding potential stress associated with overflow operation (Case 3F).

With this type of configuration, the power output of the plant with MHD out of service is 700.6 MWe with a net plant efficiency of 33.6 percent. Bringing the MHD system in service increases the net output by 95.4 MWe to 796.0 MWe with an overall efficiency of 33.5 percent. This means that plant output can be increased by about 95 MWe at the same steam flow rate without sacrificing overall efficiency (-0.1 percentage point) just by bringing the MHD system on line.

Figure C-4 shows the impact to the heat rate for part load operation. The bottom curve in this figure is the variation of the net plant output when the MHD system is out of service. The net plant efficiency drops from 33.6 percent at 700.6 MWe output to a value of 31.9 percent at 437.9 MWe net output.

The middle curve in Figure C-4 illustrates the performance of the plant with the MHD in service. The MHD system is kept at full load and the main plant load is decreased. As the main plant load decreases, the steam from the MHD system takes on larger portions of the main plant boiler feed pump requirements. At load conditions corresponding to about 60 percent of the design throttle steam flow to the main plant, the MHD system steam supplied all of the boiler feed pump power. At any load conditions less than 60 percent, the MHD system produces steam in excess of that required by the main plant boiler feed pump. This excess would have to be dumped into the condenser, reducing system efficiency. As the net output from the plant with MHD in service decreases from 796 to 510.3 MWe, the overall net plant efficiency drops from 33.5 to 32.3 percent. The corresponding increase in the net heat rate is from 10,194 to 10,579 Btu/kWh. The rate of change of variation of the net plant efficiency with the net output is not too different from the plant with MHD out of service (bottom curve).

The top dotted curve in Figure C-4 is given for comparison. This curve shows the variation of the net plant efficiency with the net plant output for a base coal-fired plant, which is designed to produce 791 MWe net output at full load conditions. For any given net output, the overall efficiency of this stand-alone plant is lower than for the combined cycle with MHD in service.

CASE (CONDENSER PRESSURE in Hg-a)	70 MWe CLASS				125 MWe CLASS														800 MWe CLASS				
	RETROFIT REF.CYCLE	FRANK BIRD			ETIWANDA UNIT #1																		
	CASE 1A (2.5)	CASE 1C (2.5)	COAL FIRED (2.5)	OIL FIRED (2.5)	CASE 2A (2.5)	CASE 2A (2.0)	CASE 2B-1 (2.5)	CASE 2B-1 (2.0)	CASE 2B-2 (2.5)	CASE 2B-2 (2.0)	CASE 2C-1 (2.5)	CASE 2C-1 (2.0)	CASE 2C-2 (2.5)	CASE 2C-2 (2.0)	CASE 2C-3 (2.5)	CASE 2C-3 (2.0)	COAL FIRED (2.5)	OIL FIRED (2.5)	CASE 3C (3.5)	CASE 3C (2.5)	CASE 3D (3.5)	CASE 3E (3.5)	CASE 3F (3.5)
POWER OUTPUT																							
GROSS MHD POWER, MWe	35.5	35.5			35.5	35.5	35.5	35.5	35.5	35.5	44.7	44.7	44.7	44.7	44.7	44.7			35.5	35.5		35.5	
GROSS STEAM POWER *, MWe	66.9*	67.4*	68.2	68.2	77.4	78.6	137.2*	138.2*	138.2*	139.2*	95.5	96.6	98.2	99.3	99.3	100.4	124.4	124.4	860.1*	873.6*	873.0*	857.7*	776.5*
COMPRESSOR POWER, MWe	-11.3	-11.3			-11.3	-11.3	-11.3	-11.3	-11.3	-11.3	-14.5	-14.5	-14.5	-14.5	-14.5	-14.5			-11.3	-11.3		-11.3	
TOPPING LOSSES, MWe	-10.5	-10.5			-10.5	-10.5	-10.5	-10.5	-10.5	-10.5	-13.1	-13.1	-13.1	-13.1	-13.1	-13.1			-10.5	-10.5		-10.5	
BOTTOMING CYCLE LOSSES, MWe	-1.1	-0.8	-6.8	-3.1	-1.2	-1.2	-8.3	-8.3	-7.8	-8.0	-1.7	-1.6	-1.6	-1.5	-1.4	-1.4	-11.4	-8.3	-79.2	-76.4	-87.1	-75.4	-75.9
NET PLANT OUTPUT, MWe	79.5	80.3	61.4	65.1	89.9	91.1	142.6	143.6	144.1	144.9	110.9	112.1	113.7	114.9	115.0	115.8	113.0	116.1	794.6	810.9	785.9	796.0	700.6
STEAM CONDITIONS																							
PRESSURE/M.S.TEMP./R/H TEMP.(PSIA/°F/°F)	1265/950/-	865/900/-	865/900/-	865/900/-	1815/1000 /1000	1815/1000 /1000	1815/1000 /1000	1815/1000 /1000	1815/1000 /1000	1815/1000 /1000	1815/1000 /1000	1815/1000 /1000	1815/1000 /1000	1815/1000 /1000	1815/1000 /1000	1815/1000 /1000	1815/1000 /1000	1815/1000 /1000	2535/1000 /1000	2535/1000 /1000	2535/1000 /1000	2535/1000 /1000	2535/1000 /1000
THROTTLE STEAM FLOW, LBM/HR X 10 ⁻³	428.6	458.3	597.9	597.9	430.0	430.0	832.8	832.8	725.1	725.1	597.4	597.4	549.3	549.3	555.5	555.5	809.0	809.0	5694.3	5723.7	6387.7	5657.2	5657.1
REHEAT STEAM FLOW, LBM/HR					423.1	423.1	748.5	748.5	714.0	714.0	545.6	545.2	540.5	540.5	546.6	546.6	733.5	733.5	5113.5	5140.2	5300.9	5088.5	4627.1
MHD CHANNEL COOLANT DISCHARGE TEMP., °F	191	334			264	264	CHANNEL SEPARATELY COOLED	CHANNEL SEPARATELY COOLED	299	299	CHANNEL SEPARATELY COOLED	CHANNEL SEPARATELY COOLED	298	298	328	328			252	245.4		254.1	
DIFFUSER DISCHARGE ΔT(°F) FROM SAT.TEMP.	-28	0			-38	-38	-10	-10	-76	-76	-4	-4	-36	-36	-24	-24			-5	-5		-5	
HEAT INPUT																							
COAL/MHD COMBUSTOR, Mwt	183.5	183.5			183.5	183.5	183.5	183.5	183.5	183.5	229.4	229.4	229.4	229.4	229.4	229.4			183.5	183.5		183.5	
HTAH FUEL OIL (8% HEAT LOSS), Mwt	74.3	74.3			74.3	74.3	74.3	74.3	74.3	74.3	92.5	92.5	92.5	92.5	92.5	92.5			74.3	74.3		74.3	
SEED REGENERATION, Mwt	1.9	1.9			1.9	1.9	1.9	1.9	1.9	1.9	2.4	2.4	2.4	2.4	2.4	2.4			1.9	1.9		1.9	
FUEL TYPE IN EXISTING BOILER			COAL	OIL			OIL	OIL	OIL	OIL							COAL	OIL	COAL	COAL	COAL	COAL	COAL
EXISTING BOILER INPUT, Mwt			230.8	225.6			171.4	171.4	177.0	177.0							341.4	333.7	2133.7	2146.3	2340.6	2118.4	2085.5
TOTAL HEAT INPUT, Mwt	259.7	259.7	230.8	225.6	259.7	259.7	431.1	431.1	436.7	436.7	324.3	324.3	324.3	324.3	324.3	324.3	341.4	333.7	2393.4	2406.0	2340.6	2378.1	2085.5
PERFORMANCE																							
NET PLANT EFFICIENCY, %	30.6	30.9	26.6	28.9	34.6	35.1	33.1	33.3	33.0	33.2	34.2	34.6	35.1	35.4	35.5	35.7	33.1	34.8	33.2	33.7	33.6	33.5	33.6
NET PLANT HEAT RATE, BTU/KW-HR	11,146	11,035	12,816	11,811	9,856	9,727	10,315	10,243	10,340	10,283	9,978	9,871	9,732	9,631	9,622	9,564	10,311	9,807	10,279	10,124	10,163	10,194	10,159

* INCLUDES POWER FOR ALL STEAM
DRIVEN ACCESSORIES

CASE 1A: RETROFIT REFERENCE CASE
MODIFIED AVCO/ETF CYCLE

CASE 1C: RETROFIT REFERENCE TOPPING CYCLE
FRANK BIRD CLASS TURBINE - FULL LOAD

CASE 2A: RETROFIT REFERENCE TOPPING CYCLE
ETIWANDA CLASS TURBINE - PART LOAD
NO HIGH PRESSURE FEEDWATER HEATERS

CASE 2B-1: RETROFIT REFERENCE TOPPING CYCLE
ETIWANDA CLASS TURBINE - FULL LOAD
EXISTING BOILER - PARTIALLY FIRED
ALL FEEDWATER HEATERS IN SERVICE

CASE 2B-2: RETROFIT REFERENCE TOPPING CYCLE
ETIWANDA CLASS TURBINE - FULL LOAD
EXISTING BOILER - PARTIALLY FIRED
NO HIGH PRESSURE FEEDWATER HEATERS

CASE 2C-1: SCALE-UP OF RETROFIT REFERENCE TOPPING CYCLE
ETIWANDA CLASS TURBINE - PART LOAD
ALL FEEDWATER HEATERS IN SERVICE

CASE 2C-2: SCALE-UP OF RETROFIT REFERENCE TOPPING CYCLE
ETIWANDA CLASS TURBINE - PART LOAD
NO HIGH PRESSURE FEEDWATER HEATERS

CASE 2C-3: SCALE-UP OF RETROFIT REFERENCE TOPPING CYCLE
ETIWANDA CLASS TURBINE - PART LOAD
NO HIGH PRESSURE FEEDWATER HEATERS
SPLIT ECONOMIZERS

CASE 3C: RETROFIT REFERENCE TOPPING CYCLE
800 MWe SUBCRITICAL STEAM PLANT
MHD HEAT RECOVERY SUPPLIES
TOP FEEDWATER HEATER

CASE 3D: 800 MWe G/C REFERENCE F0331L PLANT

CASE 3E: RETROFIT REFERENCE TOPPING CYCLE
700 MWe SUBCRITICAL STEAM PLANT
MHD HEAT RECOVERY SUPPLIES
TOP FEEDWATER HEATER

CASE 3F: 700 MWe SUBCRITICAL STEAM PLANT

TABLE C-1
MHD RETROFIT POWER CYCLES
PERFORMANCE SUMMARY

TABLE C-2
COMPARISON OF TURBINE CYCLE PARAMETERS

<u>Parameters</u>	<u>Turbine Cycle 1 800 MWe Without MHD (Case 3D)</u>	<u>Turbine Cycle 2 900 MWe With MHD</u>	<u>Turbine Cycle 3 800 MWe With MHD (Case 3C)</u>
Turbine type	TC 4F 33.5	TC 6F 30	TC 4F 33.5
Throttle flow, lbm/hr	6,387,657	6,387,657	5,694,260
Exhaust hood flow, lbm/hr	3,769,616	4,185,250	3,772,874
Back end loading, %	95.0	83.6	95.0
Turbine net power, MWe	859*	926	827
Final feedwater temp. °F	551	545	548
BFP power by MHD system, %	0.0	75	90
BFP power by main plant, %	100.0	25.0	10
Condenser pressure, in. Hga	3.5	3.5	3.5

* In this turbine cycle, modeling did not account for the flue gas reheating by the extraction steam, whereas Turbine Cycles 2 and 3 have the feature of flue gas reheating by steam taken from the crossover point. Therefore, with Turbine Cycle 1, an estimate was made for the loss of power due to steam required to reheat the flue gas. This resulted in a net turbine output of 849.5 MWe.

SCHEME A
REFERENCE SIZE MHD SYSTEM
LARGE TURN-DOWN OF TURBINE

SCHEME B
REFERENCE SIZE MHD
PARTIAL FIRING OF EXISTING BOILER

SCHEME C
LARGER SIZE MHD
TURBINE AT NEAR FULL LOAD

FIGURE C-1
RETROFIT INTEGRATION
SCHEMES - 125 MWe

SCHEME A
MHD REPLACES TOP FEEDWATER HEATER

SCHEME B
MHD POWERS MAIN PLANT'S AUXILIARIES

SCHEME C
DIRECT STEAM CONNECTION

FIGURE C-2
RETROFIT INTEGRATION
SCHEMES - 8

FIGURE C-3
(CASE 1A)
RETROFIT REFERENCE CASE
MODIFIED AVCO/ETF CYCLE
(2.5" Hg)

FIGURE C-4
PART LOAD HEAT RATE
FOR LARGE POWER PLANTS

APPENDIX D
EQUIPMENT LISTS

APPENDIX D
EQUIPMENT LISTS

This appendix contains the following equipment lists:

	<u>Page</u>
Table D-1 MHD Reference Topping Cycle	D-2
Table D-2 MHD Reference Topping Cycle Scaled-Up 25 Percent	D-5
Table D-3 70 MWe Class Plant Steam Bottoming Cycle	D-8
Table D-4 125 MWe Class Plant Steam Bottoming Cycle	D-9
Table D-5 800 MWe Class Plant Steam Bottoming Cycle	D-10

Quantities, design conditions, sizes, etc., were obtained from system flow diagrams, conceptual plot plans, and heat balances.

TABLE D-1
MHD REFERENCE TOPPING CYCLE EQUIPMENT LIST
(SPECIFIED SIZES ARE TYPICAL)

ITEM	QUANTITY	DESCRIPTION
1. Burner (Single Stage Combustor)	1	Pressure 3.32 atm Coal: 5% Moist, 56,925 lb/hr, 10,962 Btu/lb Air: 2,500°F, 452,064 lb/hr Seed: 150°F, 11,153 lb/hr Slag: 2,771°F, 4,260 lb/hr Plasma Gas: 4,361°F, 515,880 lb/hr Inner Diameter x Length 3.67 ft x 16.5 ft Overall Length: 21.5 ft
2. Nozzle	1	Plasma Gas: 515,880 lb/hr Outlet Pressure: 2.15 atm Outlet Temp: 4,126°F Velocity: 2,624 ft/sec
3. MHD Generator	1	Inlet Plasma: 4,126°F, 515,880 lb/hr Length: 29.6 ft Inlet Area: 2.87 ft ² Outlet Area: 8.45 ft ² Length-to-Diameter Ratio: 15.4 Enthalpy Extraction: 14.13%
4. Magnet	1	Field: 4.95 Tesla (Maximum) Length: 42.6 ft Dewar Outside Diameter: 11.75 ft (3.56 m)
5. Diffuser	1	Inlet Area: 8.45 ft ² Outlet Area: 33.8 ft ² Length: 33.3 ft Pressure: 0.83 atm Outlet Temp: 3,631.7°F
6. High Temperature Air Heater	1	Combustion Air: 3.35 atm, 452,064 lb/hr, 427 to 2,500°F Fuel Oil Input: 13,099 lb/hr Secondary Air: 189,735 lb/hr, 1,100°F Recirc. Gas Flow: 198,016 lb/hr, 1,100°F Gas Flow: 0.83 atm, 400,850 lb/hr, 576°F Total No. of Vessels: 4 (All Active) Diameter x Height: 15 ft x 85 ft
7. Main Compressor	2	Outlet pressure: 3.73 atm Electric Consumption: 11.3 MWe Air Flow: 452,064 lb/hr Steam Turbine Driven
8. Coal Dryer	1	Coal In: 22.7% Moist, 69,959 lb/hr Coal Out: 5% Moist, 56,925 lb/hr Gas Required: 150,932 lb/hr, 0.83 atm, 576°F
9. Recirculated Air Low Temperature Air Heater	1	Air Flow: 237,310 lb/hr, 80 to 518°F Gas Flow: 249,918 lb/hr, 576 to 250°F Heat Rating: 6.35 MWt Height x Width x Length: 20 ft x 20 ft x 10 ft
10. Recirculated Air Blower	2	Air Flow: 237,310 lb/hr, 0.83 atm Electrical Consumption: 1.16 MWe Capacity: 1 MWe each
11. Recirculated Gas Blower	2	Gas Flow: 198,016 lb/hr, 1.11 atm Electrical Consumption: 1.25 MWe Capacity: 1.2 MWe each
12. Primary Radiant Furnace (Evaporator)	1	Steam: 256,884 lb/hr In: 1,402 psia, 557°F Out: 1,402 psia, 587°F Gas: 515,880 lb/hr In: 0.83 atm, 3,631°F Out: 0.83 atm, 2,890°F Height x Width x Length: 110 ft x 22 ft x 22 ft Heat Rating: 46.5 MWt

TABLE D-1 (CONTINUED)
MHD REFERENCE TOPPING CYCLE EQUIPMENT LIST
(SPECIFIED SIZES ARE TYPICAL)

ITEM	QUANTITY	DESCRIPTION
13. Secondary Radiant Furnace (Evaporator 2)	1	Steam: 207,635 lb/hr In: 1,402 psia, 557°F Out: 1,402 psia, 587°F Gas: 515,880 lb/hr In: 0.83 atm, 2,890°F Out: 0.83 atm, 1,880°F Height x Width x Length: 110 ft x 24 ft x 24 ft Heat Rating: 37.6 MWt
14. Convective Section Furnace (Evaporator 3)	1	Steam: 56,667 lb/hr In: 1,402 psia, 557°F Out: 1,402 psia, 587°F Gas: 563,455 lb/hr In: 0.83 atm, 2,012°F Out: 0.83 atm, 805°F Height x Width x Length: 110 ft x 18.5 ft x 18.5 ft Heat Rating: 10.3 MWt
15. Superheater - 1	1	Steam: 521,186 lb/hr In: 1,325 psia, 587°F Out: 1,292.5 psia, 785°F Gas: 563,455 lb/hr In: 0.83 atm, 1,608°F Out: 0.83 atm, 805°F Height x Width x Length: 32 ft x 21 ft x 30 ft Heat Rating: 28.6 MWt
16. Superheater - 2	1	Steam: 521,186 lb/hr In: 1,292.5 psia, 785°F Out: 1,265 psia, 950.4°F Gas: 515,880 lb/hr In: 0.83 atm, 2,890°F Out: 0.83 atm, 1,880°F Height x Width x Length: 48.5 ft x 24 ft x 24 ft Heat Rating: 16.1 MWt
17. Recirculated Gas-To-Gas Heat Exchanger	1	Cold Gas: 198,016 lb/hr In: 1.11 atm, 331.1°F Out: 0.95 atm, 1,100°F Hot Gas: 563,455 lb/hr In: 0.83 atm, 2,012°F Out: 0.83 atm, 1,854°F Height x Width x Length: 60 ft x 18.5 ft x 18.5 ft Heat Rating: 12.4 MWt
18. Recirculated Air Heat Exchanger	1	Air: 189,735 lb/hr In: 1.11 atm, 518°F Out: 0.95 atm, 1,100°F Gas: 563,195 lb/hr In: 0.83 atm, 1,854°F Out: 0.83 atm, 1,608°F Height x Width x Length: 60 ft x 18.5 ft x 18.5 ft Heat Rating: 8.4 MWt
19. Economizer - 2	1	Water: 521,186 lb/hr In: 1,620 psia, 372°F Out: 1,544 psia, 408°F Gas: 563,455 lb/hr In: 0.83 atm, 805°F Out: 0.83 atm, 676.9°F Height x Width x Length: 25 ft x 20 ft x 6 ft Heat Rating: 5.7 MWt
20. Economizer - 1	1	Water: 491,536 lb/hr In: 250 psia, 192°F Out: 200 psia, 311°F Gas: 563,455 lb/hr In: 0.83 atm, 676.9°F Out: 0.83 atm, 275°F Height x Width x Length: 46 ft x 20 ft x 6 ft Heat Rating: 17.3 MWt

TABLE D-1 (CONTINUED)
MHD REFERENCE TOPPING CYCLE EQUIPMENT LIST
(SPECIFIED SIZES ARE TYPICAL)

ITEM	QUANTITY	DESCRIPTION
21. Electrostatic Precipitator/ Separator	1	Gas: 779,323 lb/hr In: 0.83 atm, 255°F Out: 0.83 atm, 250°F Inlet Loading: 11,888 lb/hr Outlet Loading: 64.2 lb/hr Efficiency: 99.45%
22. Induced Draft Fan	1	Gas: 767,499 lb/hr In: 0.83 atm, 250°F Out: 1.05 atm, 255°F Electrical Consumption: 4.1 MWe
23. Turbine-Generator	1	Power Output: 55.6 MWe, Turbine Type: Tandem Compound Generator Type: Conventionally Cooled Steam: 428,640 lb/hr, 1,265 psia, 950.4°F
24. Deaerator	1	Feedwater Capacity: 521,186 lb/hr, 170.2 psia In: 311°F Out: 369°F
25. Main Condenser	1	Operating pressure: 2.5 in. Hga Cooling Water Design Flow: 69,800 gpm No. of Tubes: 5,000 Capacity: 0.7×10^8 Btu/hr
26. Boiler Feed Pump	2	Water Flow: 521,186 lb/hr In: 170.2 psia Out: 1,620 psia Electrical Consumption: 947 kWe Capacity: 750 kWe each
27. Booster Pump (Condensate)	-	See Booster Pump (No. 30)
28. Condensate Pump	1	Flow: 491,520 lb/hr In: 2.5 in. Hga Out: 150 psia Electrical Consumption: 82 kWe
29. Air Ejector	1	Condensate Water In: 491,520 lb/hr Steam In: 1,530 lb/hr, 181 psia Water Out: 491,520 lb/hr, 111.8°F, (H) = 80.2 Btu/lb
30. Booster Pump	2	Condensate Water Flow: 491,520 lb/hr In: 150 psia, 191.6°F Out: 250 psia, 191.8°F Electrical Consumption: 61 kWe Capacity: 75 kWe each
31. Steam Turbine For Main Air Compressor	1	Steam In: 1,265 psia, 950°F, 92,546 lb/hr Steam Out: 1.228 psia, 84,359 lb/hr
32. Coal Handling	-	30 Days Storage Yard Coal Crusher Coal Unloading Area Firing Rate: 840 tons per day (22.7% Moist, as received coal) Belt Conveyor Coal Higher Heating Value: 8,920 Btu/lb

TABLE D-2
MHD REFERENCE TOPPING CYCLE SCALED-UP 25 PERCENT
EQUIPMENT LIST
(SPECIFIED SIZES ARE TYPICAL)

ITEM	QUANTITY	DESCRIPTION
1. Burner (Single Stage Combustor)	1	Pressure: 3.39 atm Coal: 5% Moist, 71,156 lb/hr, 10,962 Btu/lb Air: 2,500°F, 565,079 lb/hr Seed: 150°F, 13,941 lb/hr Slag: 2,771°F, 5,326 lb/hr Plasma Gas: 4,363°F, 644,850 lb/hr Inner Diameter x Length: 4.2 ft x 17 ft Overall Length: 22.25 ft
2. Nozzle	1	Plasma Gas: 644,850 lb/hr Pressure: 2.2 atm Outlet Temp: 4,130°F Velocity: 2,624 ft/sec
3. MHD Generator	1	Plasma Flow: 4,130°F, 644,850 lb/hr Length: 29.6 ft Inlet Area: 3.52 ft ² Outlet Area: 10.43 ft ² Length to Diameter Ratio: 13.9 Enthalpy Extraction: 14.2%
4. Magnet	1	Field: 5 Tesla (Maximum) Length: 42.6 ft Dewar Outside Diameter: 14.75 ft (4.46 m)
5. Diffuser	1	Inlet Area: 10.43 ft ² Outlet Area: 41.72 ft ² Length: 36.98 ft Pressure: 0.83 atm Outlet Temp: 3,647°F
6. High Temperature Air Heater	1	Combustion Air: 3.49 atm, 565,079 lb/hr, 438 to 2,500°F Fuel Oil Input: 16,298 lb/hr Secondary Air: 236,064 lb/hr, 1,100°F Recirc. Gas Flow: 246,367 lb/hr, 1,100°F Gas Flow: 0.83 atm, 498,881 lb/hr, 577°F Total No. of Vessels: 4 (All Active) Diameter x Height: 17 ft x 85 ft
7. Main Air Compressor	2	Pressure: 3.88 atm Electric Consumption: 14.5 MWe Air Flow: 565,079 lb/hr Electric Driven
8. Coal Dryer	1	Coal In: 22.7% Moist, 87,449 lb/hr Coal Out: 5% Moist, 71,156 lb/hr Gas Req'd: 188,568 lb/hr, 0.83 atm, 577°F
9. Recirculated Air Low Temperature Air Heater	1	Air Flow: 295,435 lb/hr, 80 to 517°F Gas Flow: 310,161 lb/hr, 577 to 250°F Heat Rating: 7.89 MWt Height x Width x Length: 20 ft x 20 ft x 13 ft
10. Recirculated Air Blower	2	Air Flow: 295,435 lb/hr, 0.83 atm Electrical Consumption: 1.44 MWe Capacity: 1.5 MWe each
11. Recirculated Gas Blower	2	Gas Flow: 246,367 lb/hr, 1.11 atm Electrical Consumption: 1.56 MWe Capacity: 1.75 MWe each

TABLE D-2 (CONTINUED)
MHD REFERENCE TOPPING CYCLE SCALED-UP 25 PERCENT
EQUIPMENT LIST
(SPECIFIED SIZES ARE TYPICAL)

ITEM	QUANTITY	DESCRIPTION
12. Primary Radiant Furnace (Evaporator 1)	1	Steam: 403,614 lb/hr In: 2,050 psia, 615.5°F Out: 1,900 psia, 628.5°F Gas: 644,850 lb/hr In: 0.83 atm, 3,647°F Out: 0.83 atm, 2,890°F Height x Width x Length: 110 ft x 24.6 ft x 24.6 ft Heat Rating: 59.8 MWt
13. Secondary Radiant Furnace (Evaporator 2)	1	Steam: 123,699 lb/hr In: 2,050 psia, 615.5°F Out: 1,900 psia, 628.5°F Gas: 644,850 lb/hr In: 0.83 atm, 2,890°F Out: 0.83 atm, 1,880°F Height x Width x Length: 110 ft x 25.5 ft x 25.5 ft Heat Rating: 18.3 MWt
14. Convection Section Furnace (Evaporator 3)	1	Steam: 40,493 lb/hr In: 2,050 psia, 615.5°F Out: 1,900 psia, 628.5°F Gas: 704,220 lb/hr In: 0.83 atm, 2,012°F Out: 0.83 atm, 805°F Height x Width x Length: 50 ft x 10 ft x 10 ft Heat Rating: 6 MWt
15. Superheater - 1	1	Steam: 555,967 lb/hr In: 1,900 psia, 628.5°F Out: 1,853 psia, 643°F Gas: 704,220 lb/hr In: 0.83 atm, 1,601°F Out: 0.83 atm, 805°F Height x Width x Length: 32 ft x 3 ft x 3 ft Heat Rating: 6 MWt
16. Reheater	1	Steam: 546,598 lb/hr In: 287 psia, 557°F Out: 263 psia, 1,000°F Gas: 704,220 lb/hr In: 0.83 atm, 2,012°F Out: 0.83 atm, 805°F Height x Width x Length: 45 x 6 x 5 Heat Rating: 36.7 MWt
17. Superheater - 2	1	Steam: 555,967 lb/hr In: 1,853 psia, 643°F Out: 1,815 psia, 1,000°F Gas: 644,850 lb/hr In: 0.83 atm, 2,890°F Out: 0.83 atm, 1,880°F Height x Width x Length: 48.5 ft x 27 ft x 27 ft Heat Rating: 20.1 MWt
18. Recirculated Gas-To-Gas Heat Exchanger	1	Cold Gas: 246,367 lb/hr In: 1.11 atm, 311.1°F Out: 0.95 atm, 1,100°F Hot Gas: 704,220 lb/hr In: 0.83 atm, 2,012°F Out: 0.83 atm, 1,777°F Height x Width x Length: 60 ft x 21 ft x 21 ft Heat Rating: 15.4 MWt
19. Recirculated Air Heat Exchanger	1	Air: 236,064 lb/hr In: 1.11 atm, 517°F Out: 0.95 atm, 1,100°F Gas: 704,220 lb/hr In: 0.83 atm, 1,777°F Out: 0.83 atm, 1,601°F Height x Width x Length: 60 ft x 20.6 ft x 20.6 ft Heat Rating: 10.5 MWt

TABLE D-2 (CONTINUED)
MHD REFERENCE TOPPING CYCLE SCALED-UP 25 PERCENT
EQUIPMENT LIST
(SPECIFIED SIZES ARE TYPICAL)

ITEM	QUANTITY	DESCRIPTION
20. High Temperature Economizer - 2	1	Water: 567,806 lb/hr In: 2,205 psia, 324°F Out: 2,135 psia, 458°F Gas: 704,220 lb/hr In: 0.83 atm, 805°F Out: 0.83 atm, 372°F Height x Width x Length: 75 ft x 55 ft x 17 ft Heat Rating: 23.6 MWt
21. Low Temperature Economizer	1	Water: 567,806 lb/hr In: 200 psia, 212°F Out: 195 psia, 244°F Gas: 704,220 lb/hr In: 0.83 atm, 372°F Out: 0.83 atm, 275°F Height x Width x Length: 15 ft x 7.5 ft x 2.5 ft Heat Rating: 5.3 MWt
22. Electrostatic Precipitator/ Separator	1	Gas: 972,875 lb/hr In: 0.83 atm, 255°F Out: 0.83 atm, 250°F Inlet Dust Loading: 14,395 lb/hr Outlet Dust Loading: 80 lb/hr Efficiency 99.45%
23. Induced Draft Fan	1	Gas: 958,560 lb/hr In: 0.83 atm, 250°F Out: 1.05 atm, 255°F Electrical Consumption: 5.15 MWe
24. Turbine-Generator (Rated)	1	Power Output: 125 MWe, Turbine Type: Tandem Compound Generator Type: Conventionally Cooled Steam: 555,479 lb/hr, 1,815 psia, 1,000°F, 1,000°F
25. Deaerator	1	Pressure: 14.7 psia Capacity: 568,296 lb/hr
26. Main Condenser	1	Operating Pressure: 2.5 in. Hga Cooling Water Designed Flow: 87,250 gpm Capacity: 0.875×10^9 Btu/hr
27. Boiler Feed Pump	2	Water Flow: 567,806 lb/hr In: 178.6 psia Out: 2,205 psia
28. Booster Pump (Condensate)	-	See Booster Pump (No. 30)
29. Condensate Pump	1	Flow: 542,557 lb/hr In: 2.5 in. Hga Out: 45.5 psia
30. Air Ejector	1	Condensate Water In: 542,557 lb/hr Steam In: 4.98 psia, 510 lb/hr Water Out: 542,557 lb/hr, 110°F Enthalpy (H): 78.1 Btu/lb
31. Booster Pump	2	Condensate Water Flow: 568,296 lb/hr In: 14.7 psia, 211.9°F Out: 200 psia, 212.2°F
32. Coal Handling	-	30 Days Storage Yard Coal Crusher Coal Unloading Area Firing Rate: 1,050 tons per day (22.7% Moist, as received coal) Belt Conveyor Coal Higher Heating Value: 8,920 Btu/lb

TABLE D-3
70 MW CLASS PLANT STEAM BOTTOMING CYCLE
EQUIPMENT LIST (BASED ON FRANK BIRD PLANT)

ITEM	QUANTITY	DESCRIPTION
1. Turbine-Generator (Rated Capacity)	1	Power Output: 66 MWe Turbine Type: Tandem Compound, Double Flow Generator Type: Conventionally Cooled Steam: 485,260 lb/hr, 865 psia, 900°F
2. Feedwater Heater	2 (In Operation) 2 (Out of Service)	(Low Pressure) (1 High Pressure and 1 Low Pressure)
3. Main Condenser	1	Operating Pressure: 2.5 in. Hga Cooling Water Designed Flow: 38,400 gpm Capacity: 0.4×10^9 Btu/hr
4. Boiler Feed Pump	1	Water Flow: 551,431 lb/hr In: 200 psia Out: 1,194.2 psia
5. Condensate Pump	1	Flow: 551,431 lb/hr In: 1.23 psia Out: 68 psia
6. Air Ejector	1	Condensate Water: 551,431 lb/hr Steam: 865 psia, 800 lb/hr

TABLE D-4
125 MW CLASS PLANT STEAM BOTTOMING CYCLE
EQUIPMENT LIST (BASED ON ETIWANDA UNIT 1)
(SPECIFIED VALUES ARE FOR RATED CAPACITY)

ITEM	QUANTITY	DESCRIPTION
1. Turbine-Generator (Rated Capacity)	1	Power Output: 125 MWe Turbine Type: Tandem Compound, Triple Flow Generator Type: Conventionally Cooled Steam: 920,000 lb/hr, 1,950 psia, 1,000°F
2. Feedwater Heater	1	Low Pressure (In Operation)
	1	Leak Steam Condenser (In Service)
	2	Intermediate Pressure (Out of Service)
	2	High Pressure Heater (Out of Service)
3. Deaerator (Rated Capacity)	1	Pressure: 13.23 psia Cooling Water Design Capacity: 1,000,000 lb/hr
4. Main Condenser (Rated Capacity)	1	Operating Pressure: 2.0 in. Hga Cooling Water Design Flow: 70,000 gpm Capacity: 0.73×10^9 Btu/hr
5. Boiler Feed Pump (Rated Capacity)	6	10-Stage Horizontal, Centrifugal, Barrel Type Flow: 940,000 lb/hr, 5,010 ft total discharge head Efficiency: 76%, 2,000 bhp, 3,570 rpm Discharge/Suction Nozzle, 8 in
6. Booster Pump (Condensate)	4	Single stage Double Suction: 1,100,000 lb/hr Suction Head: 35 ft Discharge Head: 430 ft, 225°F Efficiency: 75%, 300 bhp
7. Heater Drain Pump	4	Suction Head: 32 ft at 227°F Dynamic Head: 95 ft Flow: 218,000 lb/hr, 65 ft total discharge head Efficiency: 79.3%, 8.73 bhp
8. Condensate Pump	1	Capacity: 1,750 gpm Efficiency: 77% Total Discharge Head: 180 ft Suction Temp: 101°F Electrical Consumption: 76 kWe
9. Air Ejector	1	Nozzle Pressure: 314 psia Absolute Back Pressure Primary Inlet: 1 psia Secondary Inlet: 4 psia Air-Vapor Mixture Removed: 127 lb/hr Flow To Condenser: 510 lb/hr, 162°F
10. Existing Boiler (Not in operation for retrofit evaluation)	1	Main Steam: 920,000 lb/hr, 1,950 psia, 1,000°F Reheat Steam: 830,000 lb/hr, 423 psia, 1,000°F Feedwater: 448.4°F

TABLE D-5
800 MWE CLASS PLANT STEAM BOTTOMING CYCLE
EQUIPMENT LIST
(SPECIFIED VALUES ARE FOR RATED CAPACITY)

ITEM	QUANTITY	DESCRIPTION
1. Turbine-Generator (Rated Capacity)	1	Power Output: 825.5 MWe Turbine Type: Tandem Compound, Four Flow Generator Type: Conventionally Cooled Steam: 5,700,000 lb/hr, 2,535 psia, 1,000°F
2. Feedwater Heater	3	Surface Area:
	4	High Pressure (in operation): 53,500 ft ² Low Pressure (in operation): 95,000 ft ²
3. Deaerator	1	Pressure: 172 psia Capacity: 5,700,000 lb/hr
4. Main Condenser	1	Cooling Water Designed Flow: 370,000 gpm 20°F rise in Circulating water Capacity: 3.7 x 10 ⁹ Btu/hr
5. Boiler Feed Pump	2	Water Flow: 5,700,000 lb/hr In: 3,170 psia Out: 172 psia
6. Condensate Pump	2	Capacity: 10,000 gpm Outlet Pressure: 240 psia Electrical Consumption: 1,240 kWe (50% each)
7. Booster Pump	2	Water Flow: 297,323 lb/hr In: 60 psia, 252.2°F Out: 250 psia, 252.6°F Electrical Consumption: 67 kWe Capacity: 35 MWe each
8. Existing Boiler	1	Main Steam: 2,535 psia, 1,000°F, 5,700,000 lb/hr Reheat Steam: 592.6 psia, 1,000°F, 5,090,000 lb/hr Feedwater: 548°F
9. Coal Handling	-	30 Days Storage/Crusher Building/Car Dumping Positioning & Thawing Equipment, etc. Firing Rate: 10,500 tons per day (As received) Coal Higher Heating Value: 8,920 Btu/lb

APPENDIX E
COST ESTIMATES

APPENDIX E COST ESTIMATES

The cost estimates presented in this appendix support the material presented in Section 6.3. The contents are in tabular format as follows:

<u>TABLE</u>	<u>DESCRIPTION</u>	<u>PAGE</u>
E-1	The category listing for the modified Federal Power Commission Code of Accounts and Sub-Accounts used in preparing the cost estimates.	E-3

Cost Estimates by major accounts for:

The Stand-Alone ETF Reference Plants:

E-2	o 260 Mwt input level	E-8
E-3	o 324 Mwt input level	E-9

Selected Retrofit Plants in the:

E-4	o 70 MWe class with a 260 Mwt MHD topping cycle	E-10
E-5	o 125 MWe class with a 324 Mwt MHD topping cycle	E-11
E-6	o 800 MWe class with a 260 Mwt MHD topping cycle	E-12
E-7	The Frank Bird Plant Retrofit (260 Mwt) (Includes Site Modifications)	E-13
E-8	Etiwanda Unit 1 Retrofit (324 Mwt) (Includes Site Modifications)	E-14

<u>TABLE</u>	<u>DESCRIPTION</u>	<u>PAGE</u>
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Fossil Plant "benchmark" cost estimates:

E-9	o 70 MWe coal-fired plant	E-15
E-10	o 125 MWe coal-fired plant	E-16
E-11	o 125 MWe oil-fired plant	E-17
E-12	o 800 MWe coal-fired plant	E-18

The assumptions and guidelines used in preparing the retrofit cost estimates are detailed in Section 6.3

TABLE E-1
MODIFIED FEDERAL POWER COMMISSION
CODE OF ACCOUNTS

ACCOUNT NUMBER	ACCOUNT DESCRIPTION
311.0	Structures and Improvements
311.1	Improvements to Site
311.2	MHD Building
311.3	Bottoming Plant Building
311.4	Steam Generator Building
311.5	High Temperature Air Heater Building
311.6	Maintenance Service, Warehouse and Office Buildings
311.7	Other Buildings
311.8	Cranes and Hoists
311.9	On-site Waste Treatment
312.0	Boiler Plant
312.1	Coal Handling
312.11	Unloading and Yard Storage
312.12	Reclaim and Delivery
312.2	Slag and Ash Handling
312.4	Steam Generator
312.41	Steam Generator
312.42	Intermediate Temperature Air Heater
312.43	Instrumentation and Controls
312.44	Auxiliaries
312.5	Effluent Control
312.51	Precipitator and Breeching
312.52	Chimney
312.52	Bypass System

TABLE E-1
MODIFIED FEDERAL POWER COMMISSION
CODE OF ACCOUNTS (CONT'D.)

ACCOUNT NUMBER	ACCOUNT DESCRIPTION
312.6	Auxiliary Boiler System
312.7	Other Boiler Plant Systems
312.71	Condensate and Feedwater System
312.72	Water Treatment System
312.73	Water Supply System
314.0	Steam Turbine Generator and Auxiliary
314.1	Steam Turbine and Auxiliary
314.2	Condenser and Auxiliary
314.3	Circulating Water System
314.31	Pumps, Valves, Piping and Structures
314.32	Cooling Towers
314.4	Steam Piping Systems
314.41	Main Steam
314.42	Auxiliary Steam
314.43	Miscellaneous Piping Systems
314.5	Other Turbine Plant and Mechanical Equipment
315.0	Accessory Electric Equipment
315.1	Station and Auxiliary Transformers
315.2	Miscellaneous Motors
315.3	Switchgear and Motor Control Center
315.4	Conduit Tray, Cable and Busswork
315.5	Miscellaneous Electrical Equipment
315.6	Integrated Control System
315.7	Data Acquisition System
315.8	Emergency Power Systems

TABLE E-1
MODIFIED FEDERAL POWER COMMISSION
CODE OF ACCOUNTS (CONT'D.)

ACCOUNT NUMBER	ACCOUNT DESCRIPTION
316.0	Miscellaneous Power Plant Equipment
316.1	Fuel Oil Handling System
316.2	Fire Protection System
316.3	Machine Shop and Maintenance Shop
317.0	MHD Topping Cycle
317.1	Combustion Equipment
317.11	Coal Drying
317.12	Coal Injection
317.13	Combustor
317.14	Slag Collection System
317.2	MHD Generator
317.21	Nozzle
317.22	Channel
317.23	Diffuser and Transition Section
317.3	Magnet Subsystem
317.31	Structure
317.32	Winding Assembly
317.33	Dewar
317.34	Refrigeration System
317.35	Direct Current Power Instrumentation and Control, Other
317.4	Inverters and Electrode Subsystem
317.41	Inverters
317.42	Electric Consolidation Circuits

TABLE E-1
MODIFIED FEDERAL POWER COMMISSION
CODE OF ACCOUNTS (CONT'D.)

ACCOUNT NUMBER	ACCOUNT DESCRIPTION
317.5	Oxidizer Preheat System
317.51	Air Compressor and Drive
317.52	Combustion Air and Gas Piping, Fans
317.53	Low Temperature Air Heater
317.54	High Temperature
317.541	Vessels
317.542	Reheat Burner
317.543	Ducting
317.544	Auxiliary Equipment
317.6	Seed Subsystem
317.61	Seed Regeneration Process
317.62	Seed Injection System
317.7	Other MHD Topping Equipment
317.71*	Oxygen System
317.72*	Gasifier System
318.**	Research Equipment
319.*	Simulation Equipment
319.1	Direct Current Resistive Load Bank
350.0	Transmission Plant
350.1	Structures and Improvements
350.2	Main Transformers
350.3	Switchyard
381.0	Engineering

TABLE E-1
MODIFIED FEDERAL POWER COMMISSION
CODE OF ACCOUNTS (CONT'D.)

- * These items are not included in the Reference MHD Retrofit system.
- ** Costs for research on major MHD subsystems are not included; special engineering charges are included under Engineering (381) to cover activities related to field construction and final design details of the major MHD subsystems and equipment prepared at separate facilities.

NOTES:

1. COSTS ARE IN MID-1978 (10³) DOLLARS
2. COSTS DO NOT INCLUDE ESCALATION OR ALLOWANCE FOR FUNDS DURING CONSTRUCTION

ACCOUNT NUMBER	ACCOUNT DESCRIPTION	DIRECT COST			TOTAL DIRECT COST	INDIRECT COST	CONTINGENCY	TOTAL COST
		MATERIAL		LABOR				
		MAJOR	BOP					
311	STRUCTURES AND IMPROVEMENTS	-	8,619	7,311	15,930	3,665	3,018	22,613
312	BOILER PLANT EQUIPMENT	21,020	9,008	9,506	39,534	4,753	8,415	52,702
314	TURBOGENERATOR UNIT EQUIPMENT	6,652	2,218	3,871	12,741	1,936	2,319	16,996
315	ACCESSORY ELECTRIC EQUIPMENT	4,362	6,543	3,710	14,615	1,855	3,261	19,731
316	MISC. POWER PLANT EQUIPMENT	200	785	200	1,185	100	194	1,479
317	MHD TOPPING CYCLE	55,490	4,274	7,448	67,212	3,724	20,359	91,295
350	TRANSMISSION PLANT	904	602	632	2,138	316	368	2,822
	SUBTOTAL DIRECT ACCOUNTS	\$88,628	\$32,049	\$32,678	\$153,355	\$16,349	\$37,934	\$207,638
381	ENGINEERING							25,700
	TOTAL ESTIMATED CONSTRUCTION COST							\$233,338

TABLE E-2
SUMMARY COST ESTIMATE
STAND-ALONE ETF
(260 MWt)

NOTES:

1. COSTS ARE IN MID-1978 (10³) DOLLARS
2. COSTS DO NOT INCLUDE ESCALATION OR ALLOWANCE FOR FUNDS DURING CONSTRUCTION

ACCOUNT NUMBER	ACCOUNT DESCRIPTION	DIRECT COST			TOTAL DIRECT COST	INDIRECT COST	CONTINGENCY	TOTAL COST
		MATERIAL		LABOR				
		MAJOR	BOP					
311	STRUCTURES AND IMPROVEMENTS	-	6,569	8,160	17,729	4,080	3,359	25,168
312	BOILER PLANT EQUIPMENT	26,205	11,231	11,693	49,129	5,846	10,445	65,420
314	TURBOGENERATOR UNIT EQUIPMENT	7,624	2,541	4,435	14,600	2,218	2,657	19,475
315	ACCESSORY ELECTRIC EQUIPMENT	4,580	6,870	3,896	15,346	1,948	3,424	20,718
316	MISC. POWER PLANT EQUIPMENT	209	835	212	1,256	106	206	1,568
317	MHD TOPPING CYCLE	65,423	5,039	8,781	79,243	4,391	24,003	107,637
350	TRANSMISSION PLANT	1,039	692	727	2,458	364	423	3,245
	SUBTOTAL DIRECT ACCOUNTS	\$105,080	\$36,777	\$37,904	\$179,761	\$18,953	\$44,517	\$243,231
381	ENGINEERING							27,285
	TOTAL ESTIMATED CONSTRUCTION COST							\$270,516

TABLE E-3
SUMMARY COST ESTIMATE
STAND-ALONE, SCALED ETF
(324 MWt)

NOTES:

1. COSTS ARE IN MID-1978 (10^3) DOLLARS
2. COSTS DO NOT INCLUDE ESCALATION OR ALLOWANCE FOR FUNDS DURING CONSTRUCTION

ACCOUNT NUMBER	ACCOUNT DESCRIPTION	DIRECT COST			TOTAL DIRECT COST	INDIRECT COST	CONTINGENCY	TOTAL COST
		MATERIAL		LABOR				
		MAJOR	BOP					
311	STRUCTURES AND IMPROVEMENTS	-	6,378	5,410	11,788	2,705	2,232	16,725
312	BOILER PLANT EQUIPMENT	18,918	8,107	8,555	35,580	4,278	7,573	47,431
314	TURBOGENERATOR UNIT EQUIPMENT	-	923	403	1,326	202	241	1,769
315	ACCESSORY ELECTRIC EQUIPMENT	4,144	6,216	3,525	13,885	1,763	3,098	18,746
316	MISC. POWER PLANT EQUIPMENT	78	306	78	462	39	76	577
317	MHD TOPPING CYCLE	55,490	4,274	7,448	67,212	3,724	20,359	91,295
350	TRANSMISSION PLANT	814	542	569	1,925	285	332	2,542
	SUBTOTAL DIRECT ACCOUNTS	\$79,444	\$26,746	\$25,988	\$132,178	\$12,996	\$33,911	\$179,085
381	ENGINEERING							20,600
	TOTAL ESTIMATED CONSTRUCTION COST							\$199,685

TABLE E-4
SUMMARY COST ESTIMATE
SELECTED RETROFIT CONFIGURATION (260 MWt)
70 MWe CLASS PLANT

NOTES:

1. COSTS ARE IN MID-1978 (10³) DOLLARS
2. COSTS DO NOT INCLUDE ESCALATION OR ALLOWANCE FOR FUNDS DURING CONSTRUCTION

ACCOUNT NUMBER	ACCOUNT DESCRIPTION	DIRECT COST			TOTAL DIRECT COST	INDIRECT COST	CONTINGENCY	TOTAL COST
		MATERIAL		LABOR				
		MAJOR	BOP					
311	STRUCTURES AND IMPROVEMENTS	—	7,177	6,120	13,297	3,060	2,519	18,876
312	BOILER PLANT EQUIPMENT	23,585	10,108	10,524	44,217	5,262	9,401	58,880
314	TURBOGENERATOR UNIT EQUIPMENT	—	1,016	444	1,460	222	266	1,948
315	ACCESSORY ELECTRIC EQUIPMENT	4,351	6,527	3,701	14,579	1,851	3,253	19,683
316	MISC. POWER PLANT EQUIPMENT	82	326	83	491	42	80	613
317	MHD TOPPING CYCLE	64,769	4,989	8,693	78,451	4,347	23,763	106,561
350	TRANSMISSION PLANT	935	623	654	2,212	327	381	2,920
	SUBTOTAL DIRECT ACCOUNTS	\$93,722	\$30,766	\$30,219	\$154,707	\$15,111	\$39,663	\$209,481
381	ENGINEERING							22,000
	TOTAL ESTIMATED CONSTRUCTION COST							\$231,481

TABLE E-5
SUMMARY COST ESTIMATE
SELECTED RETROFIT CONFIGURATION (324 MWt)
125 MWe CLASS PLANT

NOTES:

1. COSTS ARE IN MID-1978 (10^3) DOLLARS
2. COSTS DO NOT INCLUDE ESCALATION OR ALLOWANCE FOR FUNDS DURING CONSTRUCTION

ACCOUNT NUMBER	ACCOUNT DESCRIPTION	DIRECT COST			TOTAL DIRECT COST	INDIRECT COST	CONTINGENCY	TOTAL COST
		MATERIAL		LABOR				
		MAJOR	BOP					
311	STRUCTURES AND IMPROVEMENTS	-	6,206	5,264	11,470	2,632	2,172	16,274
312	BOILER PLANT EQUIPMENT	18,287	7,837	8,270	34,394	4,135	7,321	45,850
314	TURBOGENERATOR UNIT EQUIPMENT	-	923	403	1,326	202	241	1,769
315	ACCESSORY ELECTRIC EQUIPMENT	3,926	5,889	3,339	13,154	1,670	2,935	17,759
316	MISC. POWER PLANT EQUIPMENT	78	306	78	462	39	76	577
317	MHD TOPPING CYCLE	55,490	4,274	7,448	67,212	3,724	20,359	91,295
350	TRANSMISSION PLANT	814	542	569	1,925	285	332	2,542
	SUBTOTAL DIRECT ACCOUNTS	\$78,595	\$25,977	\$25,371	\$129,943	\$12,687	\$33,436	\$176,066
381	ENGINEERING							20,335
	TOTAL ESTIMATED CONSTRUCTION COST							\$196,401

TABLE E-6
SUMMARY COST ESTIMATE
SELECTED RETROFIT CONFIGURATION (260 MWt)
800 MWe CLASS PLANT

NOTES:

1. COSTS ARE IN MID-1978 (10³) DOLLARS
2. COSTS DO NOT INCLUDE ESCALATION OR ALLOWANCE FOR FUNDS DURING CONSTRUCTION

ACCOUNT NUMBER	ACCOUNT DESCRIPTION	DIRECT COST			TOTAL DIRECT COST	INDIRECT COST	CONTINGENCY	TOTAL COST
		MATERIAL		LABOR				
		MAJOR	BOP					
311	STRUCTURES AND IMPROVEMENTS	-	6,500	5,600	12,100	2,800	2,295	17,195
312	BOILER PLANT EQUIPMENT	20,000	8,600	9,100	37,700	4,500	8,018	50,218
314	TURBOGENERATOR UNIT EQUIPMENT	-	1,000	400	1,400	200	253	1,853
315	ACCESSORY ELECTRIC EQUIPMENT	4,200	6,400	3,600	14,300	1,900	3,208	19,408
316	MISC. POWER PLANT EQUIPMENT	70	300	80	500	40	82	622
317	MHD TOPPING CYCLE	55,500	4,300	7,400	67,200	3,700	20,348	91,248
350	TRANSMISSION PLANT	800	500	600	1,900	300	330	2,530
	SUBTOTAL DIRECT ACCOUNTS	\$81,300	\$27,300	\$26,600	\$135,100	\$13,440	\$34,534	\$183,074
381	ENGINEERING							21,000
	TOTAL ESTIMATED CONSTRUCTION COST							\$204,074

TABLE E-7
SUMMARY COST ESTIMATE
FRANK BIRD PLANT RETROFIT (260 MWt)
(INCLUDES SITE MODIFICATIONS)

NOTES:

1. COSTS ARE IN MID-1978 (10³) DOLLARS
2. COSTS DO NOT INCLUDE ESCALATION OR ALLOWANCE FOR FUNDS DURING CONSTRUCTION

ACCOUNT NUMBER	ACCOUNT DESCRIPTION	DIRECT COST			TOTAL DIRECT COST	INDIRECT COST	CONTINGENCY	TOTAL COST
		MATERIAL		LABOR				
		MAJOR	BOP					
311	STRUCTURES AND IMPROVEMENTS	-	9,186	7,834	17,020	3,917	3,224	24,161
312	BOILER PLANT EQUIPMENT	28,301	12,129	12,628	53,058	6,314	11,281	70,653
314	TURBOGENERATOR UNIT EQUIPMENT	-	1,016	444	1,460	222	265	1,947
315	ACCESSORY ELECTRIC EQUIPMENT	4,351	6,527	3,701	14,579	1,851	3,253	19,683
316	MISC. POWER PLANT EQUIPMENT	82	326	83	491	42	80	613
317	MHD TOPPING CYCLE	64,769	4,989	8,693	78,451	4,347	23,763	106,561
350	TRANSMISSION PLANT	935	623	654	2,212	327	380	2,919
	SUBTOTAL DIRECT ACCOUNTS	\$98,438	\$34,796	\$34,037	\$167,271	\$17,020	\$42,246	\$226,537
381	ENGINEERING							25,000
	TOTAL ESTIMATED CONSTRUCTION COST							\$251,537

TABLE E-8
SUMMARY COST ESTIMATE
ETIWANDA UNIT 1 RETROFIT (324 MWt)
(INCLUDES SITE MODIFICATIONS)

NOTES:

1. COSTS ARE IN MID-1978 (10^3) DOLLARS
2. COSTS DO NOT INCLUDE ESCALATION OR ALLOWANCE FOR FUNDS DURING CONSTRUCTION

ACCOUNT NUMBER	ACCOUNT DESCRIPTION	DIRECT COST			TOTAL DIRECT COST	INDIRECT COST	CONTINGENCY	TOTAL COST
		MATERIAL		LABOR				
		MAJOR	BOP					
311	STRUCTURES AND IMPROVEMENTS	-	5,214	3,864	9,078	1,932	1,110	2,120
312	BOILER PLANT EQUIPMENT	12,099	10,306	7,235	29,640	3,618	3,322	36,580
314	TURBOGENERATOR UNIT EQUIPMENT	6,019	744	1,512	8,275	756	909	9,940
315	ACCESSORY ELECTRIC EQUIPMENT	2,383	2,797	2,873	8,053	1,437	950	10,440
316	MISC. POWER PLANT EQUIPMENT	152	2,889	3,499	6,540	1,750	830	9,120
317	MHD TOPPING CYCLE	-	-	-	-	-	-	-
350	TRANSMISSION PLANT	362	270	323	955	162	113	1,230
	SUBTOTAL DIRECT ACCOUNTS	\$21,015	\$22,220	\$19,306	\$62,541	\$9,655	\$7,234	\$79,430
381	ENGINEERING							3,180
	TOTAL ESTIMATED CONSTRUCTION COST							\$82,610

TABLE E-9
SUMMARY COST ESTIMATE
70 MWe CLASS
STAND-ALONE, COAL-FIRED PLANT

NOTES:

1. COSTS ARE IN MID-1978 (10³) DOLLARS
2. COSTS DO NOT INCLUDE ESCALATION OR ALLOWANCE FOR FUNDS DURING CONSTRUCTION

ACCOUNT NUMBER	ACCOUNT DESCRIPTION	DIRECT COST			TOTAL DIRECT COST	INDIRECT COST	CONTINGENCY	TOTAL COST
		MATERIAL		LABOR				
		MAJOR	BOP					
311	STRUCTURES AND IMPROVEMENTS	-	7,604	5,635	13,239	2,818	1,603	17,660
312	BOILER PLANT EQUIPMENT	21,129	17,999	12,635	51,763	6,318	5,809	63,890
314	TURBOGENERATOR UNIT EQUIPMENT	9,733	1,203	2,446	13,382	1,223	1,465	16,070
315	ACCESSORY ELECTRIC EQUIPMENT	3,017	3,542	3,637	10,196	1,819	1,205	13,220
316	MISC. POWER PLANT EQUIPMENT	182	3,467	4,198	7,847	2,099	944	10,940
317	MHD TOPPING CYCLE	-	-	-	-	-	-	-
350	TRANSMISSION PLANT	548	410	489	1,447	245	168	1,860
	SUBTOTAL DIRECT ACCOUNTS	\$34,609	\$34,225	\$29,040	\$97,874	\$14,522	\$11,244	\$123,640
381	ENGINEERING							4,860
	TOTAL ESTIMATED CONSTRUCTION COST							\$128,500

TABLE E-10
SUMMARY COST ESTIMATE
125 MWe CLASS
STAND-ALONE, COAL-FIRED PLANT

NOTES:

1. COSTS ARE IN MID-1978 (10³) DOLLARS
2. COSTS DO NOT INCLUDE ESCALATION OR ALLOWANCE FOR FUNDS DURING CONSTRUCTION

ACCOUNT NUMBER	ACCOUNT DESCRIPTION	DIRECT COST			TOTAL DIRECT COST	INDIRECT COST	CONTINGENCY	TOTAL COST
		MATERIAL		LABOR				
		MAJOR	BOP					
311	STRUCTURES AND IMPROVEMENTS	-	7,041	5,218	12,259	2,609	1,482	16,350
312	BOILER PLANT EQUIPMENT	15,530	13,229	9,287	38,046	4,644	4,270	46,960
314	TURBOGENERATOR UNIT EQUIPMENT	9,733	1,203	2,446	13,382	1,223	1,465	16,070
315	ACCESSORY ELECTRIC EQUIPMENT	3,017	3,542	3,637	10,196	1,819	1,205	13,220
316	MISC. POWER PLANT EQUIPMENT	182	3,467	4,198	7,847	2,099	994	10,940
317	MHD TOPPING CYCLE	-	-	-	-	-	-	-
350	TRANSMISSION PLANT	548	410	489	1,447	245	168	1,860
	SUBTOTAL DIRECT ACCOUNTS	\$29,010	\$28,892	\$25,275	\$83,177	\$12,639	\$9,584	\$105,400
381	ENGINEERING							4,200
	TOTAL ESTIMATED CONSTRUCTION COST							\$109,600

TABLE E-11
SUMMARY COST ESTIMATE
125 MWe CLASS
STAND-ALONE, OIL-FIRED PLANT

NOTES:

1. COSTS ARE IN MID-1978 (10³) DOLLARS
2. COSTS DO NOT INCLUDE ESCALATION OR ALLOWANCE FOR FUNDS DURING CONSTRUCTION

ACCOUNT NUMBER	ACCOUNT DESCRIPTION	DIRECT COST			TOTAL DIRECT COST	INDIRECT COST	CONTINGENCY	TOTAL COST
		MATERIAL		LABOR				
		MAJOR	BOP					
311	STRUCTURES AND IMPROVEMENTS	-	18,822	13,949	32,771	6,975	3,974	43,720
312	BOILER PLANT EQUIPMENT	87,672	74,684	52,427	214,783	26,214	24,103	265,100
314	TURBOGENERATOR UNIT EQUIPMENT	42,687	5,276	10,726	58,689	5,363	6,408	70,460
315	ACCESSORY ELECTRIC EQUIPMENT	5,714	6,708	6,889	19,311	3,445	2,274	25,030
316	MISC. POWER PLANT EQUIPMENT	304	5,778	6,997	13,079	3,499	1,662	18,240
317	MHD TOPPING CYCLE	-	-	-	-	-	-	-
350	TRANSMISSION PLANT	1,810	1,352	1,613	4,775	807	558	6,140
	SUBTOTAL DIRECT ACCOUNTS	\$138,187	\$112,620	\$92,601	\$343,408	\$46,303	\$38,979	\$428,690
381	ENGINEERING							17,310
	TOTAL ESTIMATED CONSTRUCTION COST							\$446,000

TABLE E-12
SUMMARY COST ESTIMATE
800 MWe CLASS
STAND-ALONE, COAL-FIRED PLANT