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Assessment of Coal Technology Options and Implications for the State of Hawaii

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Assessment of Coal Technology Options and Implications for the State of Hawaii

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PREFACE

The mandate of this research report was to provide the state of Hawaii with an assessment of the potential opportunities and drawbacks of relying on coal-fired generating technologies to diversify its fuel mix and satisfy future electric power requirements. This assessment was to include a review of existing and emerging coal-based power technologies — including their associated costs, environmental impacts, land use, and infrastructure requirements — to determine the range of impacts likely to occur if such systems were deployed in Hawaii. Coupled with this review, the report was also to (1) address siting and safety issues as they relate to technology choice and coal transport, (2) consider how environmental costs associated with coal usage are included in the integrated resource planning (IRP) process, and (3) develop an analytical tool from which the Department of Business, Economic Development & Tourism of the State of Hawaii could conduct first-order comparisons of power plant selection and siting.

The prepared report addresses each element identified above. However, available resources and data limitations limited the extent to which particular characteristics of coal use could be assessed. For example, the technology profiles are current but not as complete regarding future developments and cost/emissions data as possible, and the assessment of coal technology deployment issues in Hawaii was conducted on an aggregate (not site-specific) basis. Nonetheless, the information and findings contained in this report do provide an accurate depiction of the opportunities for and issues associated with coal utilization in the state of Hawaii.

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NOTATION

The following is a list of acronyms, initialisms, and abbreviations (including units of measure) that appear in this report.

ACRONYMS

AAQS	ambient air quality standard
ABB	ASEA Brown Boveri
ACAA	American Coal Ash Association, Inc.
ACP	African, Caribbean, and Pacific
AEP	American Electric Power Co.
AES	AES Corp.
AFBC	atmospheric fluidized-bed combustion
ANL	Argonne National Laboratory
ASTM	American Society for Testing and Materials
ATEM	Argonne Technology Evaluation Model
BACT	best available control technology
BDAT	best demonstrated available technology
BFBC	bubbling fluidized-bed combustion
BGC	British Gas Corp.
BGL	British Gas Corp./Lurgi
C&D	construction and debris
Ca/S	limestone-sorbent consumption ratio
CAAA	Clean Air Act Amendments
CCT	clean coal technology
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CFB	circulating fluidized-bed
CFBC	circulating fluidized-bed combustion
CWM	coal-water mixture
DBEDT	Department of Business, Economic Development & Tourism
DOE	U.S. Department of Energy
DOT	U.S. Department of Transportation
EC	European Community
EEI	Edison Electric Institute
EIA	Energy Information Administration
EMF	electromagnetic field
EPA	U.S. Environmental Protection Agency
EPCRA	Emergency Planning and Community Right To Know Act
EPDC	Electric Power Development Co.
EPRI	Electric Power Research Institute
ESP	electrostatic precipitator
FBC	fluidized-bed combustion
FGD	flue gas desulfurization
GCC	gasification combined cycle
GE	General Electric
HCAB	Hawaii Clean Air Branch
HECO	Hawaiian Electric Co., Inc.

HRS	hazard ranking system
HRSR	heat recovery steam generator
IGCC	integrated gasification combined cycle
IRP	integrated resource plan (or planning)
KRW	Kellogg Rust-Westinghouse
LC	London Convention of 1972
LSFO	low-sulfur fuel oil
MPRSA	Marine Protection, Research, and Sanctuaries Act of 1972
MSW	municipal solid waste
NAAQS	national ambient air quality standard
NACEPT	National Advisory Council for Environmental Policy and Technology
NIMBY	not-in-my-backyard
NPL	National Priorities List
NSPS	new source performance standard
O&M	operating and maintenance
OECD	Organization for Economic Cooperation and Development
OILCT	oil combustion turbine unit
OILST	oil steam unit
PC	pulverized coal
PFBC	pressurized fluidized-bed combustion
PRC	People's Republic of China
PSD	prevention of significant deterioration
R&D	research and development
RCRA	Resource Conservation and Recovery Act
SCR	selective catalytic reduction
SNCR	selective noncatalytic reduction
TCLP	toxicity characteristic leaching procedure
TRI	Toxic Release Inventory
TSD	treatment, storage, and disposal
TSP	total suspended particulates
TVA	Tennessee Valley Authority
UNEP	United Nations Environment Programme
USWAG	Utility Solid Waste Activities Group
VOC	volatile organic compound

CHEMICALS

$\text{Ca}(\text{OH})_2$	lime
CaCO_3	limestone (calcium carbonate)
CaSO_3	calcium sulfite
CaSO_4	calcium sulfate
CaO	calcium oxide
CH_4	methane
CO	carbon monoxide
CO_2	carbon dioxide
COS	carbonyl oxysulfide
CuSO_4	copper sulfate
H_2	hydrogen
HCl	hydrogen chloride

HCN	hydrogen cyanide
HNO ₃	nitric acid
H ₂ S	hydrogen sulfide
H ₂ SO ₄	sulfuric acid
N ₂	nitrogen
NH ₃	ammonia
NO	nitrogen oxide
NO ₂	nitrogen dioxide
NO _x	nitrogen oxides
SiO ₂	silicon dioxide
SO ₂	sulfur dioxide
SO ₃	sulfite
SO ₄	sulfate
SO _x	sulfur oxides

UNITS OF MEASURE

atm	atmosphere(s)
Btu	British thermal unit(s)
cm	centimeter(s)
d	day(s)
ft	foot (feet)
ft ³	cubic foot (feet)
gal	gallon(s)
GW	gigawatt(s)
h	hour(s)
ha	hectare(s)
km	kilometer(s)
kW	kilowatt(s)
kWh	kilowatt-hour(s)
kW-yr	kilowatt-year(s)
lb	pound(s)
m	meter(s)
m ²	square meter(s)
m ³	cubic meter(s)
mg	milligram(s)
mgd	million gallon(s) per day
mi	mile(s)
min	minute(s)
MW	megawatt(s)
MWt	megawatt(s) (thermal)
ppm	part(s) per million
ppmv	part(s) per million, volume
psia	pound(s) per square inch absolute
psig	pound(s) per square inch gauge
s	second(s)
scf	standard cubic foot (feet)

t	tonne(s) (metric ton[s])
wt%	weight percent
yd ³	cubic yard(s)
yr	year(s)

ASSESSMENT OF COAL TECHNOLOGY OPTIONS AND IMPLICATIONS FOR THE STATE OF HAWAII

by

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SUMMARY

As part of its efforts to reduce dependence on foreign oil for the production of electricity, Hawaii has undertaken a study of the technical and economic feasibility of alternative energy sources, including coal. Options for increasing the use of coal to meet the state's electricity needs include repowering or retrofitting existing boilers to fire coal and the installation of new coal-fired generating facilities. The specific technology options addressed in this report include (1) conventional pulverized-coal (PC) combustion with accompanying flue gas desulfurization (FGD), (2) coal-water mixtures (CWMs), (3) slagging combustors, (4) atmospheric fluidized-bed combustion (AFBC), (5) integrated-gasification combined-cycle (IGCC) technology, and (6) pressurized fluidized-bed combustion (PFBC). Coal beneficiation is also addressed. In addition, issues related to the solid wastes from coal combustion and the siting of coal-fired generating technologies are assessed.

One of the primary constraints on the increased use of coal in Hawaii is the relatively small capacities that characterize existing generating units in the state. Existing units other than those on the island of Oahu are relatively small, with generating capacities ranging between 1 and 25 MW. These small capacities reflect the dispersed nature of the demand and the daily load pattern on the islands (i.e., large fluctuations relative to total load). The CWMs, slagging combustors, and AFBC units may be technically feasible for repowering, retrofitting, or replacing small oil-fired sources, although some economic penalty may be incurred. At the present time, IGCC systems and PFBC may be considered more practical for larger plants (100+ MW). Beneficiated (cleaned) coal could be used to reduce the emissions from any of these technologies but is probably most appropriate for CWM, slagging combustion, and AFBC units.

In addition to meeting capacity requirements, any new installation of coal-fired generating capacity (or any other fossil-fueled generating capacity) will require approval from the Hawaii Clean Air Branch (HCAB) of the State of Hawaii Department of Health. Sources considered to be major (e.g., new, repowered, or retrofitted sources) will be subject to the federal prevention of significant deterioration (PSD) regulations, as well as the Hawaii Department of Health's regulations on ambient air quality standards and air pollution control. Under federal PSD regulations, a new source is subject to best available control technology (BACT) emission standards. For sources in Hawaii, this will mean compliance with federal new source performance standards (NSPSs) as well as any more stringent standards the HCAB may wish to impose based on a case-by-case review of a particular

source and the state-of-the-art in emissions control. The HCAB rules call for a coal sulfur content of no greater than 0.5% sulfur by weight for new sources having a power-generating capacity exceeding 25 MW. This standard also applies to boilers capable of a heat input greater than 250×10^6 Btu/h. In practice, this limitation will likely be applied to boilers smaller than this.

With respect to air pollutant emissions control, IGCC, PFBC, and AFBC are considered to be the most attractive coal-fired technologies. While their emission rates for most air pollutants are considerably below those of a PC/FGD unit, the technologies (except for AFBC) have limited commercial-scale deployment at the present time. Thus, the power-generating industry still perceives these technologies as risky, relative to a PC/FGD unit. It is important to note that, if enforced, the 0.5% sulfur content standard referred to previously would negate the high emissions control efficiencies inherent in IGCC and PFBC systems, thus reducing their cost-effectiveness.

Slagging combustors also tend to produce lower emissions rates than conventional coal-fired plants or oil-fired plants, especially in the case of SO_2 and NO_x . To the extent that BACT emission levels are mandated, each of the coal technologies discussed could achieve greater levels of control through revisions to their process design or add-on equipment. Many of these enhancements are still undergoing research and development (R&D) and are subject to cost uncertainties, since, to date, only pilot or commercial-scale demonstration facilities have been constructed. Consequently, while the marginal costs for improving control of specific pollutants within any particular technology are not well determined, costs may be considered to be high. The lack of data on additional control costs is attributable, in part, to the fact that, to achieve incremental improvements, manual "fine-tuning" of the various processes will be required. In addition, constant attention to the process modifications will likely be necessary to maintain such improvements, causing costs to increase further.

S.1 COAL TECHNOLOGY ISSUES

A conventional PC power plant, equipped with particulate removal devices only, is used as the base technology in this report. The sulfur emissions from this type of plant are tied to the sulfur content of its coal feed. Conventional PC power plants may vary in size from less than 100 MW to more than 2,000 MW (2 GW) and may be used in baseload or intermediate-load applications or both. Generally, SO_2 emissions from a PC unit are controlled by using a wet scrubber that achieves 90-95% SO_2 removal efficiency (a dry scrubber, capable of 70% removal, is typically used with low-sulfur coals). A fabric filter particulate collection system may be used for particulate control. For marginal NO_x control (25-50%), in-furnace systems (e.g., low- NO_x burners, overfire air) could be used. Higher levels of control (80%+) require postcombustion systems such as selective catalytic reduction (SCR) or selective noncatalytic reduction (SNCR) technologies. With the application of add-on emissions control devices, PC units are able to meet current air quality standards; however, because of its relatively large minimum generating capacity, this technology is probably not a reasonable option for Hawaii.

A CWM-burning system is similar to a PC boiler; however, the CWM feeding operation is easier, and the fuel is relatively cleaner. Coal in the form of a slurry is pumped under pressure into the burner manifold, where it is injected into the combustion chamber. With the proper combustor design, high combustion efficiencies can be achieved. Existing oil-fired units can be retrofitted to accommodate CWMs. Changes to oil-fired units required to permit use of CWMs include the following: (1) coal-handling equipment to off-load, reclaim, transfer, grind, mix, agitate, and pump the coal; (2) bottom-ash equipment for storage and transport; (3) control equipment to desulfurize and remove particulate from the flue gas; and (4) soot blowers to accommodate the increased quantities of ash.

While the preparation and use of a CWM may increase the cost of this technology relative to PC units, this increased cost is offset to some extent by the advantages of CWMs. These advantages include transportability, ease of handling, safety, ease of feeding into the combustor, and use of cleaner coal resulting from the fuel preparation process. Although CWMs prepared from standard PC will necessitate the same pollutant control processes as PC systems, a by-product of the grinding process is removal of some of the ash and sulfur from the coal prior to combustion. Consequently, most CWMs are produced as clean fuels, thus reducing to a minimum the pollution control requirements at the user site. One of the major drawbacks of CWMs is derating. To be specific, oil-fired units that are retrofitted to burn CWMs will most likely be derated to compensate for slagging and plugging of heat transfer surfaces and for the reduction in gas velocity needed to provide additional time for combustion of coal particles and to reduce boiler erosion by coal ash.

The CWM fuel concept is expected to be applicable in developed, industrializing, and developing countries and in Hawaii. The designs are somewhat similar to those using other fuel systems; however, Hawaii would probably not be inclined to be one of the first commercial users of this or any other first-generation technology, despite its special applicability to an island situation.

Slagging combustors can be used to replace oil- and gas-fired combustors in large-scale commercial, industrial, and utility settings. In addition, new boilers of this type could be designed. Because of their compactness, slagging combustors are especially desirable for plants with space constraints. Oil-fired boilers are particularly suitable for slagging-combustor retrofit. In addition, in contrast to CWMs, derating is minimal for this application. In the United States, approximately 60,000 coal-, gas-, and oil-fired combustors are candidates for slagging-combustor retrofit. In Hawaii, approximately 1,000 MW of oil-fired capacity may be considered for retrofit. Although slagging combustors represent a relatively new technology, extensive R&D has been carried out by private U.S. firms.

Slagging combustors (including advanced cyclone combustors) offer significant environmental advantages over established coal combustion systems by simultaneously controlling SO_2 , NO_x , and particulate levels during the combustion process. Emissions of SO_2 are controlled by injecting a sorbent (usually limestone) into the combustor; the resulting CaSO_4 is removed with the slag. Formation of NO_x is inhibited by maintaining a fuel-rich environment during initial combustion, followed by a fuel-lean combustion zone. The solid

products from the combustor consist of ash, calcium and sulfur compounds, and unused calcined limestone.

There are no special coal-handling requirements other than the addition of a limestone feed system. The slagging combustor produces a molten slag containing the ash and captured sulfur as a solid waste prior to boiler entry, with the removal of ash as slag rejection at 80-90%. Coal-water mixtures as fuel can simplify fuel storage, handling, and feed systems. Injection of sulfur sorbent, either with the fuel or separately into the combustor or into the combustion gases, eliminates the need for an FGD system in many applications, and high-sulfur, high-ash, and low-fusion-temperature coals can be used. Coal type is not a limiting feature, but higher ash coals and those with poor slagging characteristics are less desirable.

In fluidized-bed combustion (FBC), of which AFBC is one variation, a bed of solid particles is suspended in a stream of upward-flowing air. The suspended particles behave like a fluid. During combustion, steam is formed as the flue gas heats tubes containing flowing water that are located within the bed or above the bed (or both). The steam is then sent to a steam turbine for the generation of electricity. The distinctive aspect of FBC is that when coal and a sorbent — such as limestone — are injected into the bed, SO_2 is absorbed by the sorbent to produce a dry and benign solid. Atmospheric fluidized-bed combustion operates at or near atmospheric pressure.

Fluidized-bed combustion was first applied in Germany more than 60 years ago. By the 1960s, basic investigations of FBC were underway in the United Kingdom, the People's Republic of China (PRC), and the United States. The initial emphasis was on AFBC. The renewed interest in this technology can be attributed to its ability to remove SO_2 from flue gas and thereby meet U.S. Environmental Protection Agency (EPA) emission limitations without resorting to installation of costly (FGD) systems (i.e., back-end add-on systems).

From an economic perspective, future coal, gas, and oil prices will continue to influence the pace of AFBC development. Given the added flexibility of fuel switching, the argument can be made that all forms of AFBC technology are economically competitive under certain market conditions. The AFBC units range in size from 10 to 150 MW or more; however, an economic penalty is incurred as capacity is reduced. Hence, while this option would appear to be relevant to the situation in Hawaii (e.g., two 90-MW Barbers Point AFBC units), these capacity constraints may limit the applicability of AFBC.

In recent years, IGCC has become a rapidly emerging alternative for new electric generating plants. Such plants require 15% less land area than PC plants with FGD and exhibit substantially improved thermal efficiency and environmental performance. Because of its advantages of modularity, rapid and staged on-line generation capability, high efficiency, environmental controllability, and reduced land and natural resource needs, IGCC has become a strong contender in meeting future energy needs. An IGCC system gasifies a solid fuel, producing a fuel gas for a combined-cycle power generation system. Typical usable solid fuels include bituminous, lignite, or subbituminous coals. Coal may be delivered to a pressurized gasifier in a coal-water slurry or as a dry feed, depending on the gasifier concept.

There are fundamental differences between power plants based on IGCC technology and PC plants. Because energy is extracted at a higher temperature in the gas turbine than is possible in a steam turbine alone, IGCC can theoretically achieve higher efficiencies than a PC plant. Also, in an IGCC plant, gaseous and solid emissions are dealt with before combustion. The lower mass and higher pressure of the product gas results in a 300-fold decrease in the volume needing treatment for particulate and sulfur removal. This decrease in volume significantly affects plant size and cost. Waste products from an IGCC plant usually consist of elemental sulfur or sulfuric acid, either of which can be marketed as by-products, which improves the economics of the process. Control of NO_x is also easier and more efficient in an IGCC plant than in a PC plant.

Innovations in IGCC design are expected to occur both in fundamental aspects (e.g., improvements in hot-gas cleanup and increases in gas-turbine firing temperature) and cycle refinements (e.g., intercooled steam-injected gas turbine). Although coal-fired cycles will not attain the efficiency of natural-gas-fired cycles, the differences should narrow and eventually lead to coal becoming the most economic fuel.

For Hawaii, an oxygen-blown IGCC system is inappropriate at this time; due to the present cost of the oxygen plant, a cost-effective IGCC system is larger than the scale suitable for Hawaii. Alternatively, if an air-blown gasifier is successfully demonstrated on a commercial scale, then an IGCC plant may become economic in the 50-100-MW range, thus making IGCC potentially appropriate for Hawaii.

Similar to an AFBC unit, a PFBC unit consists of a furnace in which a bed of coal and limestone (sorbent) is suspended in a stream of upward-flowing pressurized air. Crushed coal is burned under high pressure in a sorbent bed, usually comprised of limestone or dolomite. A compressor provides high-pressure combustion air at the bottom of the combustor to maintain the coal and sorbent in a highly turbulent suspended state. The turbulence promotes good particle mixing, and the bed depth allows long gas residence time, which leads to high combustion efficiency and SO_2 absorption.

The PFBC plants are expected to be able to fire a wide range of coals. Moreover, no technical problems are anticipated in meeting NSPSs with PFBC units; however, as with all new technologies, costs and reliable performance are major issues.

By repowering a boiler with PFBC technology using the existing plant area, coal- and waste-handling equipment, and steam turbine equipment, the life of a plant can be extended. Although the initial cost may be somewhat high, there are no net incremental operating costs; unlike the addition of a scrubber to a PC boiler, PFBC efficiency is not degraded by parasitic losses. Also, the addition of the gas turbine provides an increase in plant capacity of about 40%. Although impressive from the economic, environmental, and efficiency perspectives, whether and to what extent this technology offers potential for Hawaii remains to be seen. The minimum scale currently envisioned is 50 MW, although the optimal size is somewhat larger and will only be determined once additional plants are constructed.

In general, beneficiation processes reduce the ash and inorganic sulfur content of coals. Advanced coal preparation processes are being developed to further reduce ash and sulfur content and to increase Btu recovery, generally by reducing the moisture content. The environmental benefits of advanced coal preparation processes include lower SO₂ emissions and decreased amounts of ash that must ultimately be collected and disposed of. Lower ash levels also improve power plant operation; however, some beneficiation processes result in increased shipping costs because of the smaller particle size and the increased amount of moisture in the coal. Because the costs and associated benefits largely depend on the coal involved, little can be ascertained without investigation and analysis of specific coals in particular situations.

S.2 WASTE MANAGEMENT ISSUES

In addition to a variety of air pollutants, including SO₂, NO_x, CO, CO₂, VOCs, and TSPs, coal-fired power plants produce two types of solid waste: high-volume low-hazard wastes and low-volume, potentially high-hazard wastes. High-volume low-hazard wastes present the greatest concerns for utility owners and operators because of uncertain future regulatory requirements, existing limits on domestic and international disposal options, and a variety of issues associated with beneficial use applications. An overriding concern is that much more is known about the physical and chemical characteristics of wastes produced by conventional coal combustion technologies than is known about wastes from clean coal technologies (CCTs) (e.g., AFBC, IGCC, and PFBC). Hawaiian utility owners and operators should keep abreast of new research into the characterization of by-products from the various technologies under consideration, as well as the implications of those waste characterizations for application and disposal alternatives.

On April 9, 1993, the EPA published its final regulatory determination for fly ash, bottom ash, slag, and FGD wastes, in which it concluded that these wastes are exempt from RCRA Subtitle C hazardous waste regulations; however, the EPA retained the option of considering these wastes as part of its ongoing assessment of industrial nonhazardous wastes under Subtitle D of RCRA. Thus, it is possible that as a result of future actions by the EPA, these wastes could be subject to requirements that are more stringent than existing regulations under Subtitle D. In the meantime, these wastes will be managed according to state-specific solid-waste management rules. The April 9, 1993, determination did not address low-volume, potentially hazardous CCT wastes. The EPA stated that it requires additional information before a determination can be made regarding these wastes. This determination is scheduled to be issued by April 1, 1998. It is important to recognize that the April 1998 determination could conclude that these wastes are subject to Subtitle C regulations.

A final determination that coal combustion wastes are nonhazardous would allow these by-products to be used in a variety of applications without further regulation. Potential applications include cement and concrete manufacture, structural fill, soil amendments, artificial reefs, and several other applications in various stages of development and testing. This determination would be consistent with the current regulatory situation in Hawaii,

which treats coal combustion waste as a special category of wastes, the most desirable treatment for which is recycling. The viability of various applications for Hawaii depends on public perceptions, market breadth and depth, economics, transportation, storage and handling costs, quantity and quality of by-product material, need for further processing, environmental and health concerns, and potential liability. A thorough assessment of these issues as they relate to each application will be necessary for optimal decision making and planning related to increased coal-fired utility capacity.

Under a nonhazardous waste determination, if the markets for coal combustion by-products cannot absorb the volumes of coal combustion by-products generated, the wastes would be disposed of according to various on-island landfill disposal options, or the wastes would be transported to and disposed of on the U.S. mainland or in foreign countries. These options are also consistent with the current regulatory approach in Hawaii, which is that if recycling markets are insufficient to absorb all of the by-products generated, then those wastes would be disposed of in one or more types of landfills, depending on how the wastes tested for toxicity. The high costs of ocean transport and political considerations, such as increasingly stringent international restrictions and U.S. congressional activity to limit interstate transport, make off-island options relatively unattractive. Tracking political and cost issues associated with on- and off-island disposal options will help to develop informed decisions regarding nonhazardous disposal options.

A hazardous waste determination for low-volume CCT wastes would further increase the cost of disposal. There are no hazardous waste disposal facilities in the state, so either such a facility would have to be built in Hawaii, or the wastes would have to be transported to the U.S. mainland or to a foreign country for disposal. Existing and proposed international agreements would make implementation of the foreign disposal option nontrivial, and costs associated with complying with RCRA Subtitle C make the U.S. mainland disposal option uneconomic. Given current international and domestic environmental policies, ocean disposal is not a feasible option. More detailed economic analyses would need to be conducted on hazardous waste disposal options if it looked as though the EPA was heading in the direction of a hazardous waste determination for coal combustion wastes.

There is significant variability in the costs associated with various coal combustion waste management options. The most optimistic option assumes that the utility can sell the by-products as a cement replacement for \$15/ton. The most costly option assumes that the EPA will determine coal combustion wastes to be hazardous and that the utility would have to ship these wastes to the U.S. mainland for disposal at a cost of \$250-370/ton. These costs can be compared with the industry average by-product management costs of \$10-15/ton. These estimates are rough and would require additional refinement as utility owners and operators investigate specific options; for example, costs should be developed on the basis of detailed estimates from several waste management companies and different disposal locations, as well as on estimates to develop various nonhazardous and hazardous disposal facilities in Hawaii.

S.3 SITING AND INSTITUTIONAL ISSUES

Factors that are likely to influence the process of siting coal-fired generating facilities include the resource requirements (e.g., land and water) of different coal-based technologies; transportation-related issues, including the types of transport that could be used to bring coal to the generating facility and take waste material away; public perceptions; and legal and regulatory barriers. Public perceptions are especially important in light of the results of a survey conducted by the Department of Business, Economic Development & Tourism (DBEDT) in late 1992. Results of the survey suggest the potential for public opposition to coal as an option for meeting Hawaii's energy needs in the future. As such, efforts to site additional coal-fired generating facilities may experience difficulty. With respect to legal barriers and constraints, regulations regarding air and water quality are especially important. Depending on the existing air quality at a proposed site and water use and quality standards, it may be more or less difficult to construct a new facility that would result in additional pollutants such as sulfur dioxide, nitrogen oxides, and particulate matter.

Siting issues involve both qualitative and quantitative dimensions; for example, land uses can be measured in terms of the amount (and dollar value) of land required to support the proposed land use, as well as the effect the proposed land use could have on the quality of adjacent land uses. Theoretically, this latter impact could be measured in terms of dollars as well; however, in many cases, there are insufficient data to quantify such costs in dollars. Nonetheless, it is important to recognize the potential for such costs in a qualitative manner so as to better inform the decision-making process.

Costs are categorized according to whether they are private (or internal) or external. Private costs consist of out-of-pocket expenses. External costs are costs borne by a third party that is not involved in the transaction that gave rise to the costs in question. External costs need to be considered in the decision-making process in order to better ensure the efficient allocation of resources. With respect to the siting of coal-fired generating units, decisions regarding land use involve an opportunity cost (i.e., the next best use of the land) that must be factored into the decision-making process; however, adverse impacts may be imposed on third parties as well — individuals may incur external costs. Examples of possible external costs resulting from particular land uses include the loss of or a decrease in the quality of scenic vistas, displacement of current recreational activities, a decline in property values, and an increased burden on publicly provided services and infrastructure. Additional external costs are associated with the air emissions and solid wastes generated by coal-fired plants, and transport of coal and waste materials. The sum of the internal and external costs represents total social costs and constitutes the appropriate measure of total costs of the proposed action.

Regarding transport modes, coal must initially be shipped to the islands; it then must be delivered to the generating plant. While this may be a relatively straightforward matter in situations in which the generating facility is located close to the port facility, transportation will become a more important issue as the distance between the two facilities increases. Various modes are available for transporting coal over land, including trucks,

conveyor systems, and coal-slurry pipelines. Each mode offers advantages and disadvantages that must be considered when deciding where to site coal-fired generating facilities.

Truck transport of coal offers a number of advantages, including easy access to sources of coal and power plants, a high degree of flexibility, and the ability to respond quickly to customers' needs. The disadvantages of truck transport include the fact that it is labor and fuel intensive and entails high capital replacement and maintenance costs and high administrative costs. Potential adverse environmental impacts include diesel exhaust emissions, dust (from the coal being transported and the road surfaces), noise, erosion, wildlife habitat disruption, property damage, and road surface deterioration.

Conveyors have an advantage over trucks in their ability to scale slopes and make tighter turns; conveyors can be used on grades of 30-35%, while trucks are confined to surfaces of 5-8%. Conveyors also deliver coal on a continuous basis, as opposed to an intermittent basis (the case for trucks). Adverse impacts attributable to conveyors include noise, visibility impacts, and conversion of existing land uses. In addition, fugitive dust is often produced by conveyors, particularly if they are uncovered.

The advantages of slurry pipelines include their ability to be used over relatively long distances and, in most cases, to transport coal at higher speeds than conveyors. Disadvantages include reliance on large quantities of water suitable for the slurry mixture, production of slurry wastewater that is too polluted to be discharged without treatment, difficulty in ascending inclines and making tight turns, and requiring coal to be crushed to a consistency that can be accommodated by the system.

The public's reaction to a specific facility siting proposal will be influenced by a variety of factors, including population density, ambient environmental conditions, existing commercial and industrial operations, and the tastes and preferences of affected individuals; however, the relationship between each of these variables and the public's response to a particular proposal is not immediately obvious. Opposition to a proposed facility could come from public interest groups whose members do not live in the vicinity of the proposed site but who nonetheless oppose such developments in the interest of preserving undeveloped areas. As another example, individuals might strongly oppose a proposal to replace an existing facility that is about to be retired with a new generating facility. In this case, opponents might view the proposal as an opportunity to eliminate an undesirable land use altogether.

Proposals intended to improve the siting process tend to focus on a number of key issues. In general, such proposals provide for objective consideration of the technical merits of various candidate sites independent of qualitative considerations; however, qualitative considerations are also given full consideration in a separate stage of the process. In addition, the fact that the siting of noxious facilities will impose costs on certain individuals is explicitly recognized. Many current proposals recommend compensation for individuals adversely affected by a proposed site. The emphasis on compensation reflects both economic considerations — by increasing the chances that resources will be allocated efficiently — and concerns about equity.

Whether such an approach would work in Hawaii remains to be seen; for example, compensation may not be a relevant consideration where certain natural or cultural resources are concerned. However, careful consideration should be given to adopting an approach that incorporates similar elements. The experiences with siting coal-fired generating facilities in other locales suggests that a proposal will have to be well conceived and adequately address the public's concerns in order to have a reasonable probability of success.

As a technical matter, proposed major facilities and modifications to existing major facilities in attainment areas must obtain PSD permits prior to their construction. In order to obtain permits, applicants must demonstrate that their proposed action will not exceed or contribute to the exceedance of either the maximum allowable increases in ambient emissions concentrations, the NAAQSs, or any other applicable state or federal standard. Offsets may be used in some cases to reduce the impact of new sources in areas where ambient pollutant concentrations approximate their legal limits.

Impacts on visibility are of special concern in Hawaii. The EPA recognizes two forms of visibility degradation, regional haze and plume blight. Regional haze is defined as "widespread, regionally homogeneous haze from a multitude of sources which impairs visibility in every direction over a large area."¹ Given the geography of the islands, as well as the prevailing winds from the northeast that generally carry emissions out to sea, regional haze is less likely to be a problem in Hawaii; however, in some cases, emissions may stagnate in mountain valleys, causing potential environmental degradation and health problems among area residents. Plume blight is defined as "smoke dust, colored gas plumes or layered haze emitted from stacks which obscure the sky or horizon and are relatable to a single source or small group of sources."¹ Plume blight is likely to be more of a problem than regional haze because prevailing winds and the presence of mountains may cause visible emission plumes to be carried up mountain slopes.

Site availability also may be constrained by certain water use designations that apply to coastal waters surrounding the islands. In addition to the water-related needs of a coal-fired generating facility, precipitous air emissions from the facility may be carried by prevailing winds to Class AA waters or, less directly, deposited into island rivers that flow into Class AA waters. As such, candidate sites should be located in areas remote from Class AA-designated coastal waters. Water use-related conflicts will be reduced as proximity and impacts to Class AA waters decrease.

New or modified major emitting facilities are required to apply to the Hawaii Department of Health for PSD permits. The Hawaii Air Pollution Control Act contains provisions for public involvement in the permitting process that are very similar to those specified in the federal Clean Air Act. The director of the state Department of Health is required to notify the public of any major source permit application involving air pollution, and the director is allowed to hold public hearings on the application before making a final determination. Numerous additional requirements provide for public participation,

¹ 45 Fed.Reg. 80,085 (1980).

communication, and comment. These include (1) issuance of detailed public notices of the permit application to residents of both the area of the proposed facility and areas of potential impacts from the proposed facility and (2) provision of a public comment period of at least 30 days of public notice, which may be extended at the director's discretion. Applicants can expect the public to be well informed about proposed facilities, both because of the director's notices and the considerable public interest that appears to be created by development proposals in the state.

S.4 TECHNOLOGY CHOICE

The decision-making process for selecting electric generating technologies involves a complex array of factors. Traditionally, decisions were premised on the direct (e.g., capital and O&M) technology costs. More recently, governing agencies have required utilities to incorporate external costs into their decision-making process. For this project, a screening-curve spreadsheet was constructed to examine both the internal and external environmental costs of coal- and oil-fired electric-generating technologies. The use of a screening curve for technology choice is limited by the fact that it assumes a static load factor. Furthermore, other operating and performance aspects (e.g., reliability) are not addressed.

In the course of comparing alternative generating options (e.g., coal-fired AFBC versus an oil-fired combustion unit versus a PC unit), it is important to include the expected load factor when constructing cost estimates. For a given capacity, different technologies may be cost-effective, depending on the load factor. In general, coal-fired technologies become more cost-effective as the load factor increases. To correct the deficiencies in the screening curve analysis described previously, a dynamic programming capacity expansion analysis should be conducted before a final decision is made.

1 INTRODUCTION

The energy strategy planning process that the state of Hawaii has undertaken raises a number of important issues. Among these are questions regarding diversification of the state's portfolio of energy resources and how the state should proceed in its efforts to meet the growth in demand for electricity projected to occur over the next two decades. The construction of the 180-MW coal-fired cogeneration facility at Barbers Point in 1992 marked a significant departure from Hawaii's historic reliance on oil for electric power; however, the question of whether and to what extent coal-fired generating units should be developed further is unclear.

The purpose of this report is to examine a number of important issues related to the use of coal for producing electricity in Hawaii. The report is divided into six sections (including the introduction). Section 2 and Appendix A address the technological aspects of coal-fired generation of electricity. Section 3 examines questions regarding the management of solid wastes generated as part of the production process. Section 4 focuses on issues related to the siting of coal-fired generating units, and Section 5 outlines the basic features of an integrated resource planning spreadsheet model that can be used to compare the costs of different coal-fired technologies. Section 6 integrates the findings of Sections 2-5 and identifies issues that cut across these major areas.

The primary emphasis of this report is on specific coal-fired technologies that are commercially available today or will be in the next 10 years and that are relevant to Hawaii's electricity needs, given current and predicted generating capacities and load profiles in the state. Six technologies are considered: pulverized coal (PC), coal-water mixtures (CWMs), slagging combustors, atmospheric fluidized-bed combustion (AFBC), integrated-gasification combined cycle (IGCC), and pressurized fluidized-bed combustion (PFBC). Characteristics of each of the six technologies that are addressed include

- General operating characteristics,
- The applicable market,
- Capital and operating-and-maintenance (O&M) costs,
- Environmental considerations (including air emissions and solid wastes),
- Commercial availability,
- Plant size considerations, and
- Performance issues.

Since many of the advanced coal technologies considered are currently being demonstrated and commercialized, actual construction and operating cost and performance data are sparse at the time of this writing; additional information from the U.S. Department

of Energy Clean Coal Technology Demonstration Program will be forthcoming in the next several years. Moreover, the data that do exist preclude accurate estimates of scale effects on cost and incremental emissions control.

One of the more obvious questions raised in regard to the use of coal to produce electricity is what to do with the solid wastes that are generated. The answer to this question hinges, in large part, on whether such wastes are ultimately classified as hazardous, special, or nonhazardous wastes. While the April 1993 EPA ruling determined that coal wastes are exempt from RCRA Title C, the EPA retained the option to reconsider this determination under its ongoing assessment under Subtitle D. Depending upon how this issue is decided, the options available and the costs incurred by Hawaii will vary. Resolution of this issue will also impact resource use. To be specific, if such wastes are classified as nonhazardous, a variety of opportunities are available that allow these wastes to be reused or serve as inputs to other production processes. Under the alternative scenario, options are much more limited. Each of these issues is addressed in Section 3.

Section 4 addresses four major issues related to the siting of coal-fired generating facilities: (1) the resource (land and water) requirements of such facilities and their impacts on the surrounding environment, (2) transport modes that can be used to deliver coal to and waste away from the generating facility, (3) public perceptions of coal-fired generating facilities and the implications of those perceptions for the siting process, and (4) legal and regulatory constraints on the siting process. Coal-fired generating facilities require significant amounts of resources and have the potential to impose a variety of adverse impacts on the surrounding environment. Combined with the natural beauty and corresponding importance of natural amenities to the islands, public opposition may be a significant impediment to the further development of coal-fired generating capacity in Hawaii. Consequently, it is important to be aware of the factors most likely to influence the siting process and suggested procedures for facilitating the smooth functioning of this process.

Section 5 provides an overview and technical description of a spreadsheet program that permits comparison of the component costs of different electric generating technologies. These technologies include PC units, AFBC, oil-fired combined-cycle and steam turbine units, and IGCC units of varying capacities. The costs incorporated into the spreadsheet model include capital, fixed and variable operating-and-maintenance (O&M) costs, and external costs of certain air emissions that are produced by the different generating processes. This latter category is especially important because it allows for a more complete accounting of the total costs associated with each technology.

The integration and discussion of crosscutting issues presented in Section 6 are intended to shed light on the question of whether and to what extent coal-fired generating technologies are appropriate for Hawaii. In addition, important questions about the applicability of coal in Hawaii that are still unresolved are addressed.

2 CANDIDATE COAL TECHNOLOGIES — ISSUES RELATIVE TO THEIR USE IN HAWAII

Prepared by J.W. Formento

This section presents a discussion of the various advanced coal technologies potentially applicable in Hawaii. An attempt is made to highlight issues relevant to the potential use of coal in meeting the needs of the state of Hawaii for future electric power generation. The intent is to provide policymakers with information they need as they contemplate a strategy for reducing the state's dependence on oil. For the most part, the insights provided are those gained from previous or ongoing technology/market assessments by Argonne National Laboratory (ANL) and the analyses that have been conducted by Black & Veatch, Inc., for the Hawaiian Electric Company, Inc. (HECO). The Black & Veatch analyses are the siting study (Black & Veatch, Inc. 1992b) and the draft and final integrated resource plan (IRP) documents (Black & Veatch, Inc. 1992a, 1993) for HECO.

In order to reduce the state's dependency on oil for power production, Hawaiian utilities may repower existing boilers to fire coal using an advanced coal technology, switch fuel to low-sulfur coal or a coal-water mixture, or install new or "greenfield" generating facilities fueled by coal or some other fuel. Island-by-island projections of future energy needs and the corresponding facility/resource configuration plans to meet those projected needs were not available for this study. An IRP study is in progress by each of the utilities, but only the one pertaining to Oahu (by Black & Veatch, Inc. 1993) was available at the time of this writing. In lieu of firm data, this discussion concentrates on coal-based technologies for small (20-50 MW) and medium (100-250 MW) capacity power generating plants. This section presents information on the applicable market, commercialization status, costs, sizing, and performance and environmental issues related to coal technologies appropriate for such plants. The technologies discussed are

- Conventional pulverized coal (PC),
- Coal-water mixtures (CWMs),
- Slagging combustor,
- Atmospheric fluidized-bed combustion (AFBC),
- Pressurized fluidized-bed combustion (PFBC),
- Integrated-gasification combined cycle (IGCC), and
- Beneficiated (cleaned) coal.

As shown in Table 2.1, existing facilities other than those on the island of Oahu are relatively small and include many internal combustion engines. For sources under 50 MW, PC, CWMs, slagging combustors, and AFBC may be technically feasible for repowering or

TABLE 2.1 Hawaiian Utility-Owned Electricity Generation Units by Island^a

Island	No. × Size of Units (MW)	Plant Capacity (MW)	Year Commissioned
Kauai	2 × 2.0	4.0	1964
	3 × 2.8	8.4	1968
	1 × 10	10.0	1968
	1 × 19.1	19.1	1973
	1 × 24.0	24.0	1977
	8	65.5	
Hawaii	1 × 0.4	0.4	1928
	2 × 0.8	1.6	1918/1921
	3 × 1.0	3.0	1954
	1 × 1.5	1.5	1941
	1 × 2	2.0	1962
	12 × 2.5	30.0	1970-1988
	1 × 3.5	3.5	1943
	2 × 7.5	15.0	1955/1958
	1 × 11.7	11.7	1962
	1 × 14.1	14.1	1965
	1 × 15.5	15.5	1988
	1 × 17.7	17.7	1989
	1 × 23.0	23.0	1974
	28	139.0	
Oahu	3 × 50.0	150.0	1947-1954
	2 × 51.3	102.6	1973
	3 × 54.4	113.2	1957-1961
	4 × 81.6	326.4	1963-1968
	1 × 85.9	85.9	1970
	1 × 90.9	90.9	1972
	2 × 135.0	270.0	1974/1980
	2 × 90.0	180.0	1992
	18	1,319.0	
Maui	3 × 0.9	2.7	1985
	2 × 1.3	2.6	1985
	6 × 2.5	15.0	1971-1987
	1 × 4.0	4.0	1981
	2 × 5.0	10.0	1948/1949
	6 × 5.6	33.0	1973-1978
	1 × 11.5	11.5	1954
	5 × 12.5	62.5	1966-1989
	31	146.3	
Total	85	1,669.8	

^a An additional 406 MW of capacity is available under purchase power contracts with independent power producers.

Source: Energy Information Administration (1990).

new construction, although some economic penalty may be incurred. Atmospheric fluidized-bed combustion, PFBC, and IGCC systems are usually considered most practical for unit capacities above 100 MW. Beneficiated (cleaned) coal may also be of interest to meet stringent environmental standards. This coal is especially applicable where a regulatory agency specifies coal sulfur content in the permits it issues, such as is the case in Hawaii.

In the IRP for Oahu, HECO has already indicated the need for new generating capacity to serve expected growth during the course of the next 20 years. As consultant to HECO, Black & Veatch, Inc., has performed studies for HECO based on the need for four 180-MW plants on Oahu, theoretically brought on-line in 180-MW increments spaced at five-year intervals. All of the technologies discussed in this section are applicable to generating plants of this magnitude and may also be considered as replacement candidates for some of the existing plants in Hawaii, should they be retired.

2.1 TECHNOLOGICAL APPROPRIATENESS AND COST

Planners consider the important environmental ramifications, as well as the more practical aspects of electricity generation. Some of the questions raised are: Is the selected technology commercially available and well demonstrated? How well does it perform? What does it cost — now, in capital terms, and later, in operating and maintenance (O&M) expenses? Is the selected technology appropriate for an island situation? Is it practical for use in Hawaii, given the combination of physical attributes and the usage pattern the state poses? Environmental concerns, cost, technological appropriateness, and practical considerations are all vital and must be balanced.

A variety of sources have been utilized in researching, developing, and demonstrating the technologies detailed in this report. These include government and industry sources in collaborative multiyear programs such as the U.S. Department of Energy (DOE) Clean Coal Technology (CCT) Demonstration Program, extensive industry efforts such as the Electric Power Research Institute's (EPRI's) research and development (R&D) program, and individual projects between government and industry; however, to a large extent, these technologies may not yet be considered mature by a utility, even though they may have been demonstrated as feasible by a program such as DOE's CCT Program. Commercial guarantees for designs, if available, are generally far more conservative than estimates of the eventual potential for these technologies. Table 2.2 provides a comparison of the eventual capabilities of these technologies.

At this time, marginal costs for improving control of specific pollutants within any particular technology have not been determined, because these are emerging technologies, and sufficient data from an adequate number of installations from which to determine these costs are not available; however, because these are advanced technologies and incremental improvements will need to be obtained from an already-treated feedstock, costs may be expected to be high. To achieve incremental improvements, manual "fine-tuning" of the various processes will be required. To maintain such improvements, constant attention to

TABLE 2.2 Estimated Capabilities for Selected Coal-Fired Technologies

Technology	SO ₂ Control (%)	NO _x Control (lb/10 ⁶ Btu)	PM Control (lb/10 ⁶ Btu) ^a	Availability	Relative Cost
PC	Add-on	Add-on	Add-on	Now	Moderate-high
CWM	Add-on	Meets NSPS	Add-on	Now	High
Slagging combustor	90	0.2	Meets NSPS ^b	Mid-90s	Moderate
AFBC	90-95	<0.2	Add-on	Now	Moderate
IGCC	99	<0.1	<0.01	Now	High
PFBC	95	<0.1	<0.01	Mid-90s	Moderate

^a PM, Particulate matter.

^b NSPS, New source performance standard.

the process modifications will likely be necessary. Work is ongoing in government and industry programs to maximize the pollutant removal capabilities of these processes.

2.2 ENVIRONMENTAL QUALITY AND AIR EMISSION CONSIDERATIONS

Any new installation contemplated will require approval from the Hawaii Clean Air Branch (HCAB) on the basis of the source and level of air emissions expected to be generated. If a source is considered major, as most new or repowered sources are likely to be, it will be subject to the federal prevention of significant deterioration (PSD) regulations, as well as the Hawaii Department of Health's regulations on ambient air quality standards and air pollution control.

Under federal PSD regulations, a new source is subject to best available control technology (BACT) emission standards. For sources in Hawaii, this regulation will mean compliance with federal new source performance standards (NSPSs) at a minimum and compliance with any more stringent standards the HCAB may wish to impose on the basis of a case-by-case review of a particular source and the current state-of-the-art in emission control. To provide an indication of the magnitude of emission limitation mandated by these regulations, current NSPSs and the BACT determination for the recently implemented coal-fired AFBC boiler in Hawaii are provided in Table 2.3. This AFBC utility power plant is owned and operated by AES Corp. (AES) and is installed at Barbers Point.

TABLE 2.3 Current NSPS and BACT Emission Standards Affecting Hawaii

Pollutant	NSPS (lb/10 ⁶ Btu)	AES Plant	
		BACT (lb/10 ⁶ Btu)	Control
SO ₂	90% reduction	90% reduction	Limestone
SO ₂	1.2	0.3	Limestone
NO _x	0.6	0.11	SNCR
Particulates	0.05	0.015	Baghouse

The AES plant consists of two circulating fluidized-bed (CFB) boilers of a nominal 90-MW rating for each boiler. The boilers use a limestone sorbent for control of sulfur dioxide (SO₂). Although the coal approved for use at this plant has a sulfur content of 1.5% or less, any subsequent new source will be subject to a much more stringent constraint on sulfur content. The HCAB rules call for a coal sulfur content of no greater than 0.5% sulfur by weight for new sources having a power-generating capacity exceeding 25 MW. This standard also applies to boilers capable of a heat input greater than 250×10^6 Btu/h. In practice, this limitation is likely to affect boilers smaller than those regulated specifically by these rules. The HCAB expects that smaller proposed sources will base permit requests on this 0.5% fuel sulfur limitation to speed the permitting process. The Barbers Point plant is permitted at $2,150 \times 10^6$ Btu/h per boiler and uses coal rated at 11,000-12,000 Btu/lb.

From the point of view of air pollutant emissions control, IGCC is considered a very attractive technology because it, in essence, performs coal cleaning before combustion, allowing the process of preventing pollutant emissions to be more efficient. The system components of IGCC (gasifiers, turbines, etc.) are relatively well-proven technologies, although few fully integrated IGCC systems have been built. Pressurized fluidized-bed combustion is also attractive as a well-controlled source but has yet to be proven commercial to any significant extent; however, PFBC may become viable for subsequent additions to HECO's generating capacity. Atmospheric fluidized-bed combustion, of course, is currently available, as in the one Hawaiian plant already mentioned.

2.3 PLANT CAPACITY CONSIDERATIONS

The capacity requirement of a power plant is one of the most important factors in the selection of the technology to be utilized for generating power. In Hawaii, two capacity ranges appear to be of interest: medium capacity for Oahu and small capacity for the other islands. On Oahu, coal has been proven viable on a medium scale with the AES Barbers

Point Plant; however, none of the Hawaiian utilities have small-scale coal-fired plants; all small plants on Hawaii are oil, gas, or hydropower (although some sugar plantations use coal for their own electric power generation). Of the 67 units on the islands of Hawaii, Kauai, and Maui, all are under 25 MW, and 62 units are under 15 MW. Many are gas turbines or internal combustion engines and not suitable candidates for repowering with coal.

In utility applications, coal has traditionally been used in plant sizes above 50 MW, mainly because of economic reasons. At the end of 1992, 178 coal-fired power plants in the U.S. had capacities less than 50 MW (91 plants less than 25 MW). Most of them are more than 25 years old. Although smaller coal plants can be built, a nonlinear relation exists between size and cost, leading to significant economies of scale for coal-fired power plants.¹ As the size of a plant decreases, economic justification moves further from coal as a fuel source; however, the age of some facilities may be such that retiring several small plants at once and replacing them with one coal-fired plant will prove attractive. This strategy tends to reduce flexibility for a utility by increasing the reliance on the larger plant's turndown capability (discussed later in this section).

2.4 LOAD PATTERN CONSIDERATIONS

One of the attributes that goes a long way to determining the applicability of a coal technology to the needs of an entity is the ability of the technology to respond to changes in demand. Technologies differ in their ability to operate efficiently at differing output levels. Each technology has its own minimum output level (as a percent of rated load) that must be maintained for practical and cost-effective operation. Operating a plant below rated capacity is called turndown.

Both short-term (e.g., daily) and longer term (e.g., monthly, seasonal) variation may need to be taken into account. In Hawaii, the dominant use pattern appears to be a large swing in demand from day to night but much less variation on a longer term basis. The daily peak is often twice the baseload.

In order to accommodate the different patterns of demand, generating plants are operated in different modes. Typical modes include baseload, intermediate or cycling, peaking, storage, and supplemental. Operating a plant in baseline mode at or near rated capacity is usually the most efficient mode of operation; however, a fixed, constant demand profile is unusual, especially when serving a small grid, and plant managers must plan their facilities and operations to cope with varying demand. Varying the level of power produced at a plant usually occurs at the expense of efficiency. Some power generation technologies are more amenable to "demand following" than others. Thus, the choice of technology to use when repowering or constructing generating facilities will be affected by the historical and projected demand profile at the facility.

¹ No comprehensive source of suitable data with which to derive a relationship between cost and size is known to exist.

Historically, the rule of thumb has been that PC and fluidized-bed plants should be operated at no less than 40% rated capacity. Operation below that point leads to increased emissions and significantly degraded thermal efficiency. The experience of AES at the Barbers Point plant appears to belie that wisdom. According to AES (Sundstrom 1993), the plant is automatically dispatched by HECO down to one-third of its full load capacity without negative impacts. In fact, DOE has stated that "AFBC is attractive for both baseline and dispatchable power applications because it can be efficiently turned down to 25% of full load" (DOE 1993); however, in general, best overall performance is obtained through operation at higher capacity.

2.5 COAL EXPERIENCE IN HAWAII

Although coal has been used in Hawaii in the past, its use has been limited. The HECO used coal early in the century; however, this use was short-lived, and oil became the predominant fuel in the state by 1917 or so. The energy crisis of the 1970s brought about a minor resurgence in the use of coal for electricity generation by some of the island cement producers and sugar plantations. Coal consumption in Hawaii averaged about 40,000 tons/yr from 1982 until 1990. Table 2.4 estimates coal use by major consumers in Hawaii in 1991-1993. It is interesting to note that cement producers are able to use ash resulting from coal combustion in the cement-making process, so they tend to use coal with a higher ash content than other users.

As stated earlier, AES has been operating the Barbers Point plant, a coal-fired AFBC facility, on Oahu since 1992. This plant is a major facility and is the largest coal-using facility in the state. The plant demonstrates how energy needs of the state can be met using coal and an advanced coal technology and highlights the potential for additional coal use in Hawaii. The specific requirements posed by an island environment have been met with coal and have been met both cleanly and at reasonable cost. An added benefit is that the use of coal diversifies Hawaii's fuel sources, a prudent planning action for a utility in an isolated system.

2.6 COST COMPARISON OF SELECTED TECHNOLOGIES

In order to illustrate both the economies of scale as plant size increases and the approximate cost of unit sizes to fit the smaller islands, Table 2.5 presents a comparison of selected technologies at different unit sizes. These cost figures (in 1993 dollars) were taken from Black & Veatch's supply-side resource option study for HECO (Black & Veatch, Inc. 1993) except as noted otherwise. Costs for smaller units for some technologies are not presented in this table where they were not readily available. As a screening measure, one can assume that scale-down factors for technologies where small unit costs are missing will, like technologies where costs are presented, be significantly nonlinear and favor larger units. Appendix A presents a synopsis of issues relevant to coal combustion technologies potentially applicable in Hawaii.

TABLE 2.4 Estimated Coal Use, 1991-1993

Year	Estimated Coal Use (10 ³ tons)		
	Sugar Producers	Cement Producers	AES Plant
1991	9	22	0
1992	57	30	191
1993	60	30	662

TABLE 2.5 Comparison of Costs among Selected Technologies

Technology	Capacity (MW)	Capital Cost (\$ million)	Capital Cost (\$/kW)	Fixed O&M (\$/kW-yr)	Variable O&M (mills/kWh)
PC	30	117.9	3,931	221.0	2.70
	92	254.9	2,771	85.3	3.64
	184	428.5	2,329	60.1	3.50
AFBC	15	142.9	4,763	329.0	4.67
	30	124.8	4,158	202.0	4.53
	92	225.5	2,451	78.6	3.80
	184	400.6	2,177	55.6	3.61
PFBC	30	201.0	6,700	320.0	4.67
PFBC, circulating bed ^a	250	423.9	1,696	32.0	6.70
PFBC, bubbling bed ^a	250	394.2	1,577	33.0	7.02
IGCC	30	165.0	5,500	250.0	2.50
	232	653.3	2,816	90.1	4.83
Moving-bed IGCC ^a	500	750.6	1,501	32.6	5.18

^a Adjusted here to 1993 dollars from source report.

Source: IPCC (1993).

3 WASTE MANAGEMENT ISSUES

Prepared by D. Elcock

This section provides information on waste management issues of potential concern to owners and operators of coal-fired power plants in Hawaii. Section 3.1 identifies the types of waste associated with coal-fired power plants and indicates current disposal methods. Section 3.2 identifies and describes regulatory issues associated with managing coal combustion wastes, focusing on the regulatory uncertainty in classifying clean coal technology (CCT) wastes as hazardous or nonhazardous. Section 3.3 describes waste disposal options associated with three possible regulatory determinations for coal combustion wastes: hazardous, nonhazardous, and a special category of nonhazardous wastes with requirements more stringent than those for nonhazardous wastes but not as stringent as those for hazardous wastes. Section 3.4 describes beneficial applications for coal combustion wastes and notes how Hawaii-specific factors may influence these uses. In addition, Appendix G identifies and describes other waste-related issues of potential significance, including pollution prevention, multimedia permitting, and Superfund liability.

An overriding issue throughout this section is that researchers know much more about the characteristics of wastes generated from conventional coal combustion processes (e.g., pulverized coal combustion) than they do about the wastes from the newer CCTs (e.g., atmospheric fluidized-bed combustion [AFBC]), and several of these CCTs are being considered for Hawaii. Differences between CCT wastes and conventional coal combustion wastes may affect regulatory treatment, disposal options, and beneficial applications. Throughout this section, the terms "coal combustion waste" and "coal combustion by-product" are used interchangeably. Much of the literature refers to these coal combustion materials as wastes, while proponents refer to them as by-products.

3.1 TYPES OF WASTE ASSOCIATED WITH COAL-FIRED POWER PLANTS

Coal-fired utilities produce two types of waste: high-volume low-hazard wastes and low-volume, potentially high-hazard wastes. High-volume wastes include coal combustion wastes (fly ash, bottom ash, and boiler slag) and emission control wastes (e.g., flue gas desulfurization [FGD] wastes).

3.1.1 High-Volume Low-Hazard Wastes

Coal combustion waste disposal and utilization potentials depend on several factors, including the ash, sulfur, and energy content (in British thermal units) of the coal and also the combustion and emission control technologies. The following paragraphs describe high-volume wastes from conventional coal-fired power plants and CCTs. Statistics on waste generation and use come from the American Coal Ash Association, Inc. (ACAA undated). Because many CCTs have little, if any, operating history, less is known about properties of,

disposal considerations for, and beneficial applications for clean coal wastes than for conventional coal wastes.

3.1.1.1 Coal Combustion Wastes

Up to 30% of the coal burned in power plants may be noncombustible. Noncombustible materials include minerals and rocks near the coal seam and elements in the plants from which the coal was originally formed. Practically all noncombustible coal material becomes fly ash, bottom ash, or boiler slag. Industrywide, the ash content of coal (i.e., the share of coal that is noncombustible) is about 10% (EPA 1988). The types and amounts of ash produced during coal combustion depend on the source of the coal (i.e., coal-producing region), coal type (e.g., bituminous or subbituminous), production method, and boiler design.

Fly Ash. Most of the waste generated by conventional coal-fired power plants is fly ash. Fly ash consists of (1) small particles that form when molten droplets of noncombustible fuel constituents cool and (2) inert particles that remain unchanged throughout the combustion process. Utility operators collect fly ash with mechanical separators or with particulate control devices such as electrostatic precipitators, baghouses, or wet scrubbers.

In 1991, U.S. coal-fired power plants produced about 51 million tons of fly ash (73% of total coal combustion wastes). Coal combustion waste applications consumed about one-fourth of the fly ash produced; the remainder was disposed of primarily in landfills and surface impoundments.

Bottom Ash. Bottom ash consists of particles larger than fly ash particles that have never melted or that have melted and reformed into dry solid ash particles. These particles settle on the bottom of the boiler and are typically removed in hoppers. In 1991, U.S. power plants generated about 13 million tons of bottom ash (19% of total coal combustion wastes). Of this total, about 38% was used for cement and concrete, structural fill, road base and subbase, snow and ice removal, and other applications; the remainder went to disposal.

Boiler Slag. Boiler slag forms when liquefied ash particles fall to the bottom of the boiler but remain in a molten state and coalesce into large masses, which drop to the floor. Of the 6 million tons of boiler slag generated in 1991, nearly 4 million tons or 60% was used in various applications, and the rest went to disposal.

Clean Coal Technology Wastes. Numerous reports document the physical and chemical characteristics of ash and FGD sludge generated by conventional coal technologies. Perhaps the most comprehensive and most often referenced of these reports is the U.S. Environmental Protection Agency's (EPA's) 1988 report to Congress entitled *Wastes from the*

Combustion of Coal by Electric Utility Power Plants (EPA 1988.) The report does not discuss wastes produced by CCTs. The CCTs are relatively new (no U.S. commercial clean coal plants existed in 1988); therefore, empirical data related to CCTs are limited, especially with respect to waste products. As researchers refine and improve the design and operation of CCTs, the characteristics of the waste products change; yet researchers agree that the characteristics of CCT wastes differ significantly from those of conventional coal combustion wastes (Dawson et al. 1987). These differences can affect regulation, disposal practices, and by-product use. The CCTs not only produce wastes with different chemical and physical properties, but many, especially the fluidized-bed combustion (FBC) technologies, produce greater quantities of waste per megawatt of capacity (McCarthy et al. 1993). With increased volumes, reuse is an attractive alternative to disposal, appealing to regulatory agencies and providing utilities with opportunities to reduce costs. Researchers are conducting tests to characterize CCT combustion wastes, but test conclusions are of limited value because of variations in the facilities, technologies, and coals being tested.¹

Characteristics of Coal Combustion Wastes. Several characteristics of coal combustion wastes affect waste disposal and beneficial use decisions. Some of these factors are summarized in the following list:

- *Particle size.* The distribution of particle size affects density, permeability, and shear strength. Variety in particle size leads to higher density, lower permeability, and greater shear strength. Fly ash is similar to silt in terms of particle size and distribution; bottom ash and boiler slag particles range in size from that of fine sand to fine gravel.
- *Compaction.* Compaction behavior depends on compressibility, density, and moisture content and affects the amount and rate of settling. Dry compacted fly ash and bottom ash are similar to soil.
- *Permeability.* Permeability indicates the rate and quantity of leachate migration; size and particle shape and degree of compaction affect permeability. Fly ash permeability is similar to that of clay; bottom ash permeability is slightly higher.
- *Shear strength.* Shear strength depends on cohesion (the attraction of particles due to electrostatic forces) and friction among particles. Materials with high shear strengths can form steep slopes and support heavy loads. Dry nonalkaline ash is not cohesive; dry alkaline ash, such

¹ Papers presented at the Tenth International Ash Use Symposium in January 1993 document some of the test results from specific facilities and suggest potential applications, but the results are preliminary, because many of the experiments are still underway (ACAA 1993). The Electric Power Research Institute (EPRI) is also assessing the technical, economic, and marketing potentials for CCT by-products (Dawson et al. 1987; EPRI undated).

as that produced from FBC technologies, is cohesive; and, over time, its strength increases with compaction.

- *Chemical composition.* Chemical composition depends on the coal burned and the design and operation of the plant. Typically, ash consists of silicon, aluminum, iron, and calcium in their oxide forms and may also consist of other elements in smaller but highly variable quantities. These elements include magnesium, potassium, silicon, sodium, titanium, and a variety of trace elements including (but not limited to) boron, arsenic, cadmium, mercury, and strontium.
- *Pozzolan quality.* Pozzolan quality is the ability of a substance, when mixed with water and lime, to produce a cementitious material with good structural properties. Characteristics that increase pozzolan qualities include (1) the percentage of glassy spherical particles comprised of silica, alumina, and iron oxide in the ash and (2) the fineness of the ash. Fluidized-bed boilers operate at lower temperatures than pulverized coal plants; therefore, the ash produced from these boilers does not fuse into the glassy spherical particles associated with good pozzolan quality.
- *Alkalinity.* The FBC technologies produce ash containing unreacted calcium oxide, which can be highly alkaline and hence quite different from the ash resulting from other coal combustors. Although high alkalinity can be a problem for some applications, it can be an advantage in others (e.g., acidic soil treatment).
- *Heat of hydration.* Wastes with high free-lime contents (e.g., spray dryer wastes and some FBC wastes) can evolve more heat per unit weight of waste (due to hydration), and the high free-lime wastes can be reactive.

3.1.1.2 Flue Gas Desulfurization

During combustion, sulfur in the coal combines with oxygen to produce sulfur dioxide (SO_2). State and federal regulations require utilities to reduce SO_2 emissions, and a by-product of this SO_2 removal from the flue gas is FGD sludge. (FBC technologies, which remove SO_2 during the combustion process, do not produce FGD sludge.) The FGD sludge consists of spent reagent, water, ash, and unreacted absorbent. Most FGD sludges produced today come from existing wet scrubbers installed several years ago and have moisture contents of 30% or more; however, most of the newer scrubbers marketed and produced today use a wet chemistry technique that produces sludges with much lower moisture contents. Sludges from the newer technologies can be sold for wallboard manufacturing (moisture content of 10% or less), and the remainder (moisture content of 10-20%) can be disposed of in a landfill (Camponeschi 1993). Some scrubbers today use a dry chemistry technique, which, although not as efficient as wet scrubbers (wet scrubbers have a 90% removal

efficiency, and dry scrubbers have a 70% removal efficiency), produces a dry waste product. The quantities and properties of the FGD sludge generated depend on the scrubber system used, coal characteristics (e.g., sulfur and ash content), sulfur removal requirements, and whether the sludge is treated prior to disposal. Untreated sludge from wet scrubbers contains 5-15% solids (Collins 1992); after dewatering, the thickened slurry can be treated further to increase its reuse potential. Chemical characteristics depend on the reagent, amount of fly ash, and sulfur content of the coal. Often high levels of soluble calcium sulfite and sodium salts are produced, posing leaching problems for landfills. Overall, only about 2% of the 18 million tons of FGD wastes generated in 1991 were used. Some of the coal combustion technologies being considered for Hawaii may incorporate postcombustion cleaning approaches that produce FGD wastes.

3.1.1.3 Current Disposal Methods

Utilities typically dispose of high-volume, low-hazard wastes (i.e., coal combustion and FGD wastes) in one or more of the following ways:

- *Landfills*, which accept large volumes as produced or as dredged from surface impoundments. In 1988, about 53% of the generating units disposed of large-volume wastes in landfills.
- *Surface impoundments*, which are used for final disposal or for treatment or temporary storage. (After solids have settled, they can be dredged and shipped to a landfill for final disposal.) The increasing costs for surface impoundment are causing utilities to use landfills for more of their wastes.
- *Mine disposal*, which includes both mine shafts and strip-mined areas, can be less environmentally degrading than the previous methods, because disposing of the wastes in mines may cause less runoff and potential contamination from the mine itself (EPA 1988). Mine disposal occurs primarily in the western United States, where power plants are located near the coal mines that supply them.
- *Quarry disposal* for lime-laden wastes, which harden at the bottom of the quarry to plug potential leaks, and for acid wastes, which can provide an acid buffer in limestone quarries. Quarry disposal is the least commonly used method of waste disposal.

3.1.2 Low-Volume, Potentially High-Hazard Wastes

Low-volume wastes result from routine plant cleaning and water purification for the combustion process. Types and amounts depend on plant size, equipment type, equipment age, and maintenance schedule. Relative to ash and FGD sludge, these wastes are low in

volume. Because many low-volume waste streams contain chemicals used in cleaning, potentially highly hazardous waste concentrations can occur. Commonly produced low-volume wastes include pyrites, boiler blowdown, coal pile runoff, cooling tower blowdown, demineralizer regenerants and rinses, metal and boiler cleaning wastes, and sump effluents. Characteristics of each of these wastes, as described in the EPA's 1988 report to Congress, are summarized in the following list:

- *Pyrites.* Pyrites are solid mineral substances (e.g., iron sulfides and other rock-like materials) contained in raw coal. The volume depends on the amount and quality of coal.
- *Boiler blowdown.* Boiler blowdown results when impurities in the feedwater for recirculating drum-type boiler systems become concentrated and are subsequently purged. (Once-through boiler systems, which maintain pressurized steam throughout the cycle, do not require water recirculation and thus do not produce boiler blowdown.) Produced either continuously or intermittently, boiler blowdown is fairly alkaline and can contain trace elements such as copper, iron, and nickel.
- *Coal pile runoff.* Coal pile runoff occurs when water from rainfall, from spraying for dust control, or from underground streams comes into contact with coal storage piles. Runoff constituents depend on the composition of the coal (e.g., subbituminous coals typically produce neutral to alkaline runoff). Commonly found elements in coal pile runoff include copper, zinc, magnesium, aluminum, chlorine, iron, sodium, and sulfur.
- *Cooling tower blowdown.* Cooling tower blowdown contains impurities in the cooling system that can form scale in the condenser. The composition depends on makeup water characteristics (fresh, brackish, or saline) and the chemicals added to the water to prevent corrosion in the condensers and organic growths in the cooling towers. Chemicals in the blowdown can include chlorine, chromate, zinc, phosphate, and silicate.
- *Demineralizer regenerants and rinses.* Demineralizers are used to purify the makeup water of the power plant. The resulting wastes can be acidic or alkaline.
- *Metal and boiler cleaning wastes.* "Gas-side" wastes result from maintaining the gas side of the boiler and consist of soot and fly ash that build up on gas-side equipment surfaces. These materials are removed with plain water, and thus the composition of the waste streams reflects the composition of the coal. "Water-side" wastes result from using chemical solutions to clean the scale and corrosion that build up on boiler tubes, condensers, and superheaters. The cleaning

solutions and the resulting wastes can be acidic or alkaline, depending on the equipment and the type of scale removed.

- *Sump effluents.* Sump effluents result from floor and yard drains, are highly variable, and depend on the source of the waste stream. Waste streams can include process leaks and spills; equipment cleaning wastes; and seepage from groundwater, leakage, and rainfall; and components include fly ash, oil, and detergents.

These wastes are typical of conventional coal-fired power plants. The expectation is that CCTs will produce many of these wastes, especially coal pile runoff, pyrites, demineralizer regenerants and rinses, and sump effluents. Generation of other low-volume CCT wastes will depend on the specific technology and may include boiler blowdown, metal and boiler cleaning wastes, and possibly other as-yet-unknown wastes.

Low-volume wastes are typically codisposed of with high-volume wastes but can also be treated, evaporated, incinerated, neutralized, recycled, or reused. Low-volume wastes are good candidates for pollution prevention and waste minimization practices.

3.2 FEDERAL REGULATORY UNCERTAINTY

Congress enacted the Resource Conservation and Recovery Act of 1976 (RCRA 1976) to ensure the safe and environmentally acceptable management of hazardous and other solid wastes. Subtitle C of the RCRA, "Hazardous Waste Management," provides for "cradle-to-grave" management (from generation through transportation and disposal) of wastes identified as hazardous. Subtitle D of the RCRA, "State or Regional Solid Waste Plans," provides for safe management of wastes not considered hazardous. High-volume wastes from conventional coal-fired utilities (i.e., fly ash, bottom ash, boiler slag, and FGD wastes) are exempt from hazardous waste regulations at the federal level (RCRA Subtitle C) and are therefore subject to state regulation. As described in the following subsections, significant uncertainty is associated with the future regulation of low-volume, potentially high-hazard coal combustion wastes and CCT wastes. It will be important for CCT utility owners and operators to track the current regulatory determination process and the implications of those determinations for CCT waste management options.

Section 3001(b)(3)(A) of the RCRA temporarily exempted fly ash, bottom ash, boiler slag, and FGD wastes generated primarily from the combustion of coal or other fossil fuels from Subtitle C hazardous waste management regulations until certain requirements were met. This exemption is known as the Bevill exemption, or Bevill Amendment, named for the amendment's sponsor; and the exempted wastes are known as Bevill wastes. Section 8002(n) of the RCRA required the EPA to prepare a report to Congress analyzing sources and volumes of coal combustion by-products generated, disposal and utilization practices, potential dangers to human health and the environment, and other factors. Within six months of submitting the report to Congress, the EPA was required, after public hearing and comment, to decide whether to promulgate regulations under Subtitle C or determine that

such regulations were not warranted [RCRA Section 3001 (b)(3)(C)]. According to RCRA Section 3004(x), if the EPA determined that the Bevill wastes were subject to regulation under Subtitle C, the EPA can modify the requirements to take into account the special characteristics of such wastes, the practical difficulties associated with implementing such requirements, and site-specific characteristics, as long as the modified requirements ensure human health and environmental protection. Similarly, if the EPA found that these wastes were to be regulated under Subtitle D, it could also treat them as a special category of industrial nonhazardous wastes, with waste management criteria or regulations to be promulgated at the federal level. Thus, the EPA may promulgate regulations for coal combustion wastes that are more strict than those for nonhazardous wastes but less strict than those for hazardous wastes.

In 1988, the EPA submitted the required report to Congress (EPA 1988), which concluded the following:

- Fly ash, bottom ash, boiler slag, and FGD wastes do not typically exhibit hazardous characteristics under RCRA regulations.
- Other wastes from coal-fired utilities may exhibit hazardous characteristics (e.g., corrosivity or toxicity) and may merit regulation under Subtitle C.
- The use of coal combustion wastes in an environmentally safe manner will help reduce the amount of these wastes requiring disposal.

The EPA cautioned that the previous conclusions were subject to change on the basis of new information submitted through public hearings and comments.

The EPA failed to make the regulatory determination within the required six-month period. Subsequently, an Oregon citizens' group (the Bull Run Coalition) sued the EPA; and on June 26, 1992, the EPA entered into a consent decree, which addresses two categories of fossil fuel combustion wastes: (1) fly ash, bottom ash, boiler slag, and FGD wastes generated by utility combustion of coal (category 1 wastes) and (2) all remaining fossil fuel combustion wastes (category 2 wastes). The consent decree established a schedule for completing the regulatory determination for each category of waste. In accordance with the consent decree, the EPA announced on December 1, 1992, that it would need no additional study to complete the final regulatory determination on category 1 wastes and that it would finalize the regulatory determination for these wastes by August 2, 1993. The EPA also announced that it needed to study further the category 2 wastes and that it would complete a regulatory determination for those wastes by April 1, 1998.

On August 9, the EPA published its final regulatory determination for fly ash, bottom ash, boiler slag, and FGD wastes, which concluded that these wastes would continue to be exempt from regulation under Subtitle C, because they pose limited risks and because existing regulatory programs are generally adequate (EPA 1993). The scope of the regulatory

determination did not cover category 2 wastes. The implications of the August 9 regulatory determination are described in the following subsections.

3.2.1 Treatment of High-Volume Wastes

The August 9, 1993, regulatory determination continued the exemption for category 1 wastes (i.e., fly ash, bottom ash, boiler slag, and FGD wastes) from regulation under Subtitle C of the RCRA; however, the EPA retained the option of considering these wastes as part of its ongoing assessment of industrial nonhazardous wastes under Subtitle D. Thus, it is possible that in the future, the EPA could establish criteria or regulations for the management of category 1 wastes (along with other industrial nonhazardous wastes such as petroleum refining wastes) that are more strict than the existing regulations under Subtitle D. The EPA also stated in its August 9 regulatory determination that it may choose to reexamine the exemption if the characteristics of the waste streams should change as a result of implementing any provisions of the Clean Air Act as amended in 1990. Nevertheless, for the near term at least, the regulatory determination for category 1 wastes means that their management will be regulated at the state level. As described in more detail in Section 3.3.2.1, Hawaiian nonhazardous waste management regulations provide for regulation on a case-by-case basis, with the overall objective of reuse, rather than disposal.

3.2.2 Treatment of Low-Volume Wastes

The scope of the August 9, 1993, regulatory determination did not include low-volume wastes. The EPA will make a regulatory determination for these wastes (including those that are codisposed with high-volume wastes) by April 1, 1998. The EPA has said that it requires additional information before making this determination, but the low-volume wastes will remain temporarily exempt from Subtitle C regulations until that determination is made. It is possible that the April 1998 regulatory determination will conclude that low-volume wastes will come under Subtitle C regulations; however, because the volumes are relatively low and because many opportunities exist to reduce the amounts of these pollutants through pollution prevention and waste minimization, managing these wastes as hazardous would not be as difficult or costly as managing high-volume wastes as hazardous. Nonetheless, management of any waste as hazardous is problematic, because no hazardous waste disposal facilities exist in Hawaii. Issues associated with exporting hazardous wastes are discussed in Section 3.3.1.2.

3.2.3 Treatment of CCT Wastes

Because the state of Hawaii is considering the use of CCTs, it is important to note that the wastes from these technologies were not included in the August 9 regulatory determination and that the EPA will not make a determination on these wastes until April 1, 1998. The EPA emphasized in the August 9 rule that its findings only pertained to the four wastes covered in the 1988 report to Congress (i.e., fly ash, bottom ash, boiler slag,

and FGD wastes). The EPA did not study CCT wastes in the report to Congress and did not have enough information to conclude in the August 9 determination that wastes generated from these technologies, and especially from FBC technologies, are substantially similar to conventional boiler wastes. The EPA (EPA 1993) stated that

because of the current lack of data, the potential of the cofiring of limestone (in AFBC technologies) to have a significant effect on the characteristics of the wastes produced, and the potential for increased utilization of the technology, the Agency has decided to defer a decision on these wastes until further information on the growing number of facilities can be examined. Therefore these wastes . . . are outside the scope of today's regulatory determination.

Thus, roughly five years will pass before the EPA makes a determination on whether CCT wastes will be managed as hazardous, nonhazardous, or as a category with requirements less strict than those under Subtitle C but more strict than those under Subtitle D. This five-year delay provides little comfort for those responsible for planning new power plants, because long-range plans must consider waste management options that can vary significantly, depending on regulatory requirements.

3.3 DISPOSAL OPTIONS

This section describes waste disposal options and potential requirements expected under three different federal regulatory determination possibilities for coal combustion wastes: (1) hazardous; (2) nonhazardous; and (3) nonhazardous special category, with requirements less stringent than those under Subtitle C.

3.3.1 Disposal Options and Issues Associated with a Hazardous Waste Determination

The RCRA provides two methods for classifying a waste as hazardous: (1) a listed hazardous waste is a solid waste listed under 40 CFR 261(D); and (2) a characteristic hazardous waste is a solid waste that exhibits one or more of the following characteristics: ignitability, corrosivity, reactivity, or toxicity. The potential for CCT wastes to leach harmful constituents (toxins) into groundwater could conceivably lead to a hazardous determination at the federal level. At the state level, Hawaii is adding a provision to its solid waste rules to test special wastes — which would include coal combustion by-products — for toxicity (Harder 1993). Waste management requirements would depend on the results of those tests.

3.3.1.1 On-Island Disposal Options and Issues

If the EPA determines CCT wastes to be hazardous, those wastes must be managed according to the requirements of RCRA Subtitle C. Strict rules apply whether the wastes are disposed of on-site or off-site. Because Hawaii has no hazardous waste disposal facilities,

hazardous wastes generated in the state must be shipped to the mainland for disposal. In-state hazardous waste disposal would require building a hazardous waste disposal facility.

Regulatory Authorities and Requirements. Hawaii is developing its own federally approved RCRA program; and until that program is implemented, federal regulations promulgated in 40 CFR Parts 260 through 272 govern the management of hazardous wastes in the state.² State officials indicate that the proposed RCRA rules will be essentially the same as the federal rules. The following paragraphs summarize RCRA rules for hazardous waste generation; transportation; and treatment, storage, and disposal (TSD) facilities.

Generator Requirements. If coal combustion wastes were determined to be hazardous, the utility owner or operator would be a hazardous waste generator and subject to the requirements under 40 CFR Part 262. Most of these requirements are neither technically demanding nor capital intensive. Nonetheless, additional labor will be required, albeit mostly for paperwork. Generator requirements are summarized in the following list:

- *Waste identification.* Generators must determine whether their wastes are hazardous and must be aware that the EPA can change the testing requirements; for example, until 1990, the toxicity test (then known as the extraction procedure) required testing for 14 substances. In 1990, the EPA added 11 more substances to the list and changed the testing procedure to what is now known as the toxicity characteristic leaching procedure (TCLP). Such changes can make additional wastes subject to hazardous waste regulations.
- *Completion of proper forms to obtain an EPA identification number and a manifest.* The hazardous waste manifest is a form to track hazardous waste during transportation through final disposal. Generators must prepare the manifest and maintain copies for three years.
- *Proper waste handling and preparation for transportation.* Generators must package hazardous waste in containers approved by the U.S. Department of Transportation (DOT), label these wastes, and prepare transportation vehicle display placards.
- *On-site storage restrictions.* Generators may store hazardous wastes (in compliance with applicable technical and administrative requirements in 40 CFR Part 265) on-site for up to 90 days without a permit. Storing beyond 90 days without a permit violates the RCRA and can result in penalties. If the 90-day accumulation exceeds 55 gal, generators must

² The State Attorney General is reviewing draft rules, and the state expects to receive RCRA authority in 1994.

meet additional requirements (e.g., preparing contingency plans and testing programs).

- *Reporting requirements.* Generators must submit biennial reports covering hazardous waste activity for the previous year.
- *Implementation of waste minimization.* The manifest requires the generator to certify that he has a program in place to reduce waste volume and toxicity. Also, the biennial report must describe results of waste minimization.

An important consideration for the generator is that even though the utility owner or operator (the generator) may transfer hazardous wastes to a transporter or TSD facility, the generator retains liability for the wastes. Thus, if these wastes are found in the future on a Superfund site — determined to be such by the federal government or by the state of Hawaii — the utility is liable for cleanup costs, even though it transferred the wastes to a third party.

Transporter Requirements. Off-site transportation is subject to the rules under 40 CFR Part 263. If the utility owner or operator transports the wastes, the rules apply directly. If a third party transports, the rules apply to the third party, but the generator will pay increased shipping costs to support the additional manpower, time, and special equipment needed for compliance. Transporter requirements, which apply to both land and water shipping, include the following:

- Compliance with DOT provisions on labeling, marking, placarding, proper container use, and spill reporting;
- Completion and maintenance of manifests;
- Delivery of hazardous wastes only to designated TSD facilities; and
- Cleanup responsibility for accidental spills or other discharges.

Treatment, Storage, and Disposal Facility Requirements. Requirements for TSD facilities are contained in 40 CFR Part 264 and apply to all types of TSD facilities, including container storage areas, waste treatment or storage tanks, landfills, waste piles, and surface impoundments. If the utility develops on-site hazardous waste management facilities, it will be subject to these requirements; if it elects to use third-party TSD facilities,

those facilities must comply with the requirements and will pass along increased costs to the utility. Requirements for TSD facilities include the following:

- Permitting requirements;
- Unit-specific standards for each type of treatment or disposal facility (e.g., landfills must meet minimum technology requirements that include double liners, leachate collection systems, leak detection, and groundwater monitoring systems);
- Emergency preparedness and contingency plans;
- Record-keeping and reporting requirements;
- General closure and postclosure requirements; and
- Land disposal restrictions (the RCRA prohibits the disposal of any hazardous waste in or on the land, unless that waste meets EPA treatment standards for that waste; applying the required best demonstrated available technology [BDAT] can double or triple disposal costs [Haney and Casler 1990]).

3.3.1.2 Off-Island Disposal Options and Issues

Potential off-island disposal options for hazardous coal combustion wastes include shipping wastes to the U.S. mainland and to other countries and ocean disposal.

Shipment to the U.S. Mainland. No laws or regulations prohibit shipment of hazardous wastes from Hawaii to the mainland; but high costs, political considerations, and pressures in Congress to restrict interstate waste transport limit the appeal of this option. These factors are discussed subsequently.

High Costs. The costs per ton to ship hazardous coal combustion wastes to the U.S. mainland are high. Minimizing the number of shipments can reduce those costs. Depending on waste generation rate and storage area size, utilities may be able to accumulate wastes, engage fewer ships, and thereby lower shipping costs; however, storing hazardous wastes beyond 90 days requires a permit, which entails additional restrictions. Thus, regulatory compliance costs of accumulation may outweigh anticipated cost reductions.

Political Considerations. A looming political consideration is the possibility that states may be allowed to restrict imports of hazardous waste. Members of the U.S. Congress introduced several bills in the 102nd Congress that would allow states or local jurisdictions to restrict interstate municipal solid-waste (MSW) transport via bans or differential fees on

imported wastes. None of these measures passed both houses, but many measures have been reintroduced in the 103rd Congress. Interstate waste transport is an emotional issue. Suffering from short-term capacity shortages, many eastern states ship MSW to states with greater capacities. Many receiving states oppose such waste imports. In legal battles, exporting states typically win, because courts find that restricting interstate waste shipments violates the commerce clause of the U.S. Constitution. The only way for states to legally limit imports, therefore, is to change the law. Current proposals only pertain to nonhazardous MSW, which, most would agree, excludes coal combustion wastes; however, if states were allowed to restrict MSW transport, a precedent could be set for other kinds of wastes, including hazardous or coal combustion wastes. Utility owners or operators should track interstate transport activities for their potential effect on shipping coal combustion wastes to other states.

International conventions and agreements would not apply to wastes shipped from Hawaii to the mainland unless coal combustion wastes were to transit another country. The chief laws and regulations of concern for shipping to the mainland are the RCRA provisions applicable to transporters and TSD facilities described in Section 3.3.1.1.

Shipment to Other Countries. Domestic and international regulations and conventions may impact the feasibility of shipping coal combustion wastes to other countries, especially if those wastes are considered hazardous. This section describes the status of five requirements that address international hazardous waste shipments:

- RCRA Section 3017, Export of Hazardous Waste;
- The Basel Convention on the Control of Transboundary Movements of Hazardous Wastes and Their Disposal (the Basel Convention);
- The Lome IV Convention;
- Organization for Economic Cooperation and Development (OECD) agreements on wastes used for recovery; and
- Country-specific rules banning waste imports.

RCRA Section 3017, Export of Hazardous Waste. Congress added explicit provisions for the export of hazardous waste to the 1984 amendments to the RCRA (RCRA Section 3017), and the EPA has promulgated final regulations to implement these requirements (40 CFR 262.50 through 262.56). The rules apply to hazardous waste as

defined in the RCRA³ and prohibit the export of hazardous waste unless the following requirements are met:⁴

- The exporter provides advance written notice to the EPA of the plan to export hazardous waste.
- The receiving country provides prior written consent to the plan.
- The exporter attaches a copy of the consent to the manifest accompanying each waste shipment.
- The shipment conforms to the terms of the consent.

Each hazardous waste exporter must file an annual report with the EPA summarizing the types, quantities, frequency, and ultimate disposition of all hazardous waste exported during the previous year. Criminal penalties can be assessed for persons who knowingly export hazardous waste without the consent of the receiving country or violate an existing international agreement between the United States and the receiving country.

The Basel Convention. The Basel Convention is the first major international agreement to address hazardous waste imports and exports. The agreement controls hazardous waste movements across international boundaries and allows nations to ban hazardous waste imports. Two factors led to the creation of the Basel Convention: (1) increasing transboundary shipments associated with reduced waste management capacity in many countries; and (2) indiscriminate disposal of potentially hazardous wastes in developing countries, sometimes without prior consent. In 1988, the United Nations Environment Programme (UNEP) began negotiating the Basel Convention. Negotiations concluded in March 1989, at which point the convention was opened for signature; activation required 20 countries to sign and ratify the agreement. On May 5, 1992, the convention became effective; implementation issues are to be resolved at future meetings.

The United States signed the Basel Convention on March 21, 1990; and the U.S. Senate ratified its consent on August 11, 1992;⁵ however, the U.S. Congress has not passed the necessary implementing legislation, and therefore the United States is not an official party to the agreement. As described subsequently, the United States is nonetheless affected by the convention, whether or not it is a party.

³ Note that under RCRA Section 3001(b)(3)(A)(i), coal combustion wastes are currently exempt from regulation under Subtitle C, pending regulatory determination by the EPA.

⁴ If the governments of the United States and the receiving country have an international agreement establishing notice, export, and enforcement procedures for transportation and management of hazardous wastes and if the shipment conforms to that agreement, then these requirements do not apply.

⁵ The U.S. Constitution requires Senate consent to the ratification of international treaties.

Key provisions of the Basel Convention include the following:

- Exporting countries must notify and receive consent from importing countries prior to shipping hazardous or certain other wastes.
- Imports and exports of hazardous and certain other wastes between parties and nonparties are prohibited unless separate bilateral or multilateral agreements compatible with environmentally sound management exist.
- Wastes are to be exported only if the exporting country has inadequate or environmentally unsound waste disposal capacity or if the wastes are required as raw materials for recycling or recovery industries in the importing country.
- All transboundary shipments of hazardous wastes must be managed in an "environmentally sound" manner.
- Importers and exporters must comply with uniform tracking requirements.
- Parties may not export wastes prohibited by the importing country if the importing country has notified other countries of that decision.

The Basel Convention does not specifically address coal combustion wastes. Implications of various ways of treating coal combustion wastes under the Basel Convention are significant. Several options and implications are summarized as follows:

- Neither the United States nor the importing country considers the waste to be hazardous, in which case the Basel Convention requirements would not apply.
- The waste is nonhazardous according to the EPA but hazardous according to the regulatory authorities in the importing country.⁶ Even if the EPA determined that coal combustion wastes were nonhazardous, the Basel Convention could restrict shipment if an importing or transit country determined that waste to be hazardous. Because the Basel Convention restricts waste shipments to participants by nonparticipants, coal combustion waste disposal in other countries could be difficult.

⁶ A key difference between the RCRA import and export restrictions and the Basel Convention is the definition of hazardous waste. The Basel definition is much broader than the RCRA definition. Under the Basel Convention, a waste may be considered hazardous, and thus subject to restrictions, if it is identified in the annexes to the convention or is considered hazardous by the exporting, importing, or transit country.

- The United States considers the waste to be hazardous, and therefore the transport would be subject to the provisions of the Basel Convention and RCRA Section 3017.
- The wastes are considered recyclable. If wastes are required as raw materials for recycling or recovery industries by the importing country, the Basel Convention allows transboundary movement [Article 4(9)(b)]; however, whether coal combustion wastes are within this category is not clear because the convention does not specifically address coal combustion wastes. At the first meeting of the parties, in December 1992, some countries argued that the recyclable value of some hazardous waste is necessary for economic development. Other countries maintained that recycling was another word describing waste. A technical group is to develop guidelines, advice, and expertise to help identify, evaluate, and safely handle any hazardous waste labeled recyclable (*Daily Environment Report* 1992b). Thus the issue is not yet resolved.
- The wastes may be subjected to some kind of test to determine whether they are hazardous and thus subject to the Basel Convention. This scenario could result not so much from the Basel Convention itself, as from implementing legislation formulated by the U.S. Congress. One of the proposed bills to implement the Basel Convention last year (none of which passed) required using the TCLP to determine whether wastes were hazardous. Wastes from conventional coal technologies pass the TCLP in its current form; however, the EPA could change the TCLP limits, add more substances, or otherwise increase the chance of failure. Attempts to tighten the TCLP could cause some coal combustion wastes to test as hazardous even though the EPA may have issued a regulatory determination that they are not hazardous, leading to general confusion.

Other Basel Convention issues could affect coal combustion waste shipments, regardless of how coal combustion wastes are classified; for example, members have not agreed on the meaning of the term "environmentally sound management." At the first meeting after ratification, members struggled to develop technical guidelines for environmentally sound management but only resolved to prepare a manual on managing waste and to develop technical guidelines on acceptable disposal. If the resulting manual or guidelines are more strict than existing U.S. requirements, higher costs resulting from tighter management requirements further limit the export option.

Another issue is that until the United States ratifies the Basel Convention, it is unable to vote in meetings that will form implementing policy in crucial areas such as liability, compensation, environmentally sound management, and financing emergency response actions. Currently, nonparties cannot export hazardous wastes to parties to the convention unless a bilateral or multilateral agreement exists. The United States has such

agreements with Canada and Mexico but with no Pacific Rim countries. The Basel Convention allows post-ratification treaty development, but provisions for environmentally sound waste management must be included.

Clearly, Basel Convention provisions could impact waste shipments to other countries. If Hawaiian utility owners and operators want to pursue such disposal, the potential Basel implications would need more thorough investigation.

The Lome IV Convention. In December 1989, the European Community (EC) and 68 African, Caribbean, and Pacific (ACP) countries signed the Lome IV Convention, which bans the movement of hazardous and radioactive wastes between EC and ACP countries. Furthermore, ACP countries agreed to ban the import of all waste from non-EC countries. Depending on which Pacific countries signed the Lome IV Convention and which countries Hawaii may consider for export, this agreement could restrict such shipments.

Organization for Economic Cooperation and Development Agreements on Wastes for Recovery. In March 1992, the OECD (which includes the United States) agreed to provide for transboundary movement of recyclable wastes to encourage economically and environmentally satisfactory waste recovery techniques. The agreement applies to wastes subject to Basel Convention controls and divides recyclable wastes into three categories — green, amber, and red — according to their hazardous characteristics. Each category corresponds to a management approach for cross-border transfers. Green wastes are nonhazardous and may move between OECD countries without special controls. Amber wastes, which may be hazardous, will be able to move subject to notification and tacit consent. Red wastes are subject to the provisions of the Basel Convention. Because the lists of wastes and their categories are not yet complete, we do not know how coal combustion wastes would be affected. Whether coal combustion wastes would be considered wastes for recovery is not even clear; if not, the agreement would be irrelevant. Future developments related to this agreement will affect coal waste export activities.

Country-Specific Rules Banning Waste Imports. In the wake of incidents involving waste barges searching for disposal sites and unscrupulous disposal practices in some countries, many nations have unilaterally prohibited importing certain kinds of wastes. One such country is Indonesia. On November 21, 1992, the Indonesian Minister of Trade banned by decree the import of plastic waste as part of Indonesia's efforts to prevent environmental pollution and avoid threats to human health. Such a decree may set precedents for banning other types of wastes. Indonesia currently supplies low-sulfur, low-ash, high-Btu coal to the existing Barbers Point 180-MW AFBC plant operated by the AES Corp. (AES) and is a potential supplier of coal for additional power plants in Hawaii. Potential waste import restrictions could prevent implementation of options involving an Indonesian take-back of coal combustion wastes. Thus, even if coal combustion wastes survive the potential restrictions of multinational hazardous waste agreements, specific countries may ban waste imports. The area of international restrictions on hazardous waste

imports is relatively new, complex, and untested and hence will require continued monitoring and more thorough investigation if Hawaiian utility owners and operators wish to pursue export of wastes.

Ocean Disposal. Several international treaties and agreements to which the United States is a party address ocean disposal of hazardous wastes. Of these, the 1972 Convention on the Prevention of Marine Pollution by Dumping of Wastes and Other Matter (London Dumping Convention, London Convention of 1972, or LC) is the most significant. The LC corresponds to the U.S. Marine Protection, Research, and Sanctuaries Act of 1972 (MPRSA), which regulates ocean dumping of material from the United States and is actually more restrictive than the LC. The following paragraphs describe how the LC, MPRSA, and related agreements could affect ocean disposal of coal combustion wastes determined to be hazardous.

London Dumping Convention. Written in 1972 and effective in 1975, the LC is the principal international agreement on ocean disposal of wastes. Sixty-nine countries ratified the LC, including the United States. The LC bans dumping of certain hazardous wastes and requires prior authorization for ocean disposal of other wastes. The LC divides wastes into three categories, with separate requirements for each. Annex I includes wastes for which ocean disposal is prohibited; Annex II contains wastes for which ocean disposal requires a prior special permit (a permit which applies to a specific generator, material, and disposal area); and Annex III lists wastes for which ocean disposal requires a prior general permit. Permits are issued by individual parties to the convention, and issuing considerations must include characteristics and composition of the waste, characteristics of the dumping site and method of deposit, and possible effects on amenities, marine life, and other uses of the sea.

The LC does not ban dumping of RCRA hazardous wastes per se; rather, it uses effects-based testing procedures to determine if a given waste would harm the marine environment. It is possible, therefore, that an RCRA hazardous waste could pass the LC bioassay tests and hence receive an ocean disposal permit. Similarly, a waste not defined as hazardous under RCRA may fail the LC tests, in which case ocean disposal of that waste would be prohibited. According to EPA representatives who implement the LC in the United States, coal combustion wastes could fall within any one of the annexes, and how the LC would treat these wastes is not obvious, except that they would have to be tested (Lishman 1993). The EPA has not been asked for an LC determination on coal combustion wastes; to do so, the EPA would have to develop a testing procedure for these wastes that would simulate their existence in an ocean environment — a significant and lengthy undertaking (Chase 1993). A general conclusion regarding LC treatment of coal combustion wastes is not available; however, as of this writing, the MPRSA, described subsequently in more detail, is more restrictive than the LC, and hence compliance with the MPRSA assures compliance with the LC. This means that currently, ocean disposal of wastes from a Hawaiian power plant would be covered by the MPRSA; however, the LC is undergoing

amendment, and the direction is towards more, rather than fewer, restrictions.⁷ It is possible that the LC could become more restrictive than the MPRSA, and therefore utility owners or operators should monitor the LC amendment process for additional impacts on ocean dumping.

More Restrictive Agreements. For participating countries, the LC provides minimum ocean disposal requirements. Domestic laws and regional agreements may be more restrictive; for example, the South Pacific Forum⁸ is developing more stringent restrictions on hazardous waste transit and disposal in the South Pacific region.⁹ Proposed restrictions include banning hazardous waste disposal and transit in the region and adding certain products and technologies to the list of substances subject to restrictions. The United States has legal and navigational concerns about these restrictions; but as a nonmember, it can only participate in these talks as an advisor. Thus, restrictions could be enacted without U.S. concurrence. Even if such restrictions were not enacted, their formal proposal indicates a trend toward increasing limitations on ocean waste disposal and transit. The U.S. State Department foresees a hazardous waste dumping ban in the South Pacific within the next three years (Robinson 1993).

Marine Protection, Research, and Sanctuaries Act of 1972. The MPRSA is the U.S. domestic legislation corresponding to the LC and provides for the regulation and permitting of ocean dumping and transportation for the purpose of dumping materials into the oceans. The implementing regulations, which detail permitting procedures, are contained in 40 CFR Parts 220 through 233. The United States played a major role in the drafting of the LC, which occurred at around the same time as the MPRSA. As with the LC, the MPRSA does not use the RCRA definition of hazardous waste. Permit writers evaluate disposal applications on the basis of expected environmental, aesthetic, recreational, economic, and alternative use impacts resulting from the proposed waste disposal request; however, the public hearing processes required for permitting are strict enough that most RCRA hazardous wastes would be denied disposal permits (Redford 1993). More significantly, the Ocean Dumping Ban Act, which amended the MPRSA in 1988, bans ocean disposal of industrial waste and sewage sludge after December 31, 1991. (See Section 3.3.2.2

⁷ For example, currently, a voluntary ban exists on the dumping of nonhazardous industrial wastes. The U.S. State Department staff indicates that once definitional problems are solved, the ban will probably become a permanent amendment to the treaty.

⁸ The South Pacific Forum is a group of South Pacific nations concerned about their environment. The United States is not a member of the South Pacific Forum but is a member of the South Pacific Regional Environment Programme, which has a technical working group that provides advice and input to the South Pacific Forum discussions.

⁹ These restrictions are likely to be more expansive than the Basel Convention as well, because the Basel Convention applies to transboundary movements from one nation to another, whereas the South Pacific Forum proposals would apply to the entire region, including the high seas as well as boundaries.

for more discussion of the industrial waste disposal ban.) If ocean disposal of industrial waste is banned, permitted ocean disposal of hazardous waste would be unlikely.

3.3.1.3 Hazardous Waste Disposal Costs

Hazardous waste disposal costs are significantly higher than nonhazardous waste disposal costs. Disposal of hazardous wastes generated in Hawaii costs about \$1,500-\$3,000/55-gal drum (including transport to the U.S. mainland) (Harder 1993). By assuming that a 55-gal drum equals about half of a cubic yard and that the density of coal combustion by-products averages about 85 lb/ft³, these costs translate into roughly \$2,600-\$5,200/ton. Bulk shipment and disposal may provide lower but still relatively high costs. Chemical Waste Management estimates the following land-based transportation and disposal costs per ton; disposal in a Subtitle C-approved landfill would cost \$124/ton, including the 10% county tax on hazardous waste disposal; stabilization, if required, would cost \$117/ton; and transportation from a California port to a California hazardous waste landfill would be \$39/ton, including a \$2.50/ton charge for a truck liner.¹⁰ Waldron Steamship Co. (a shipper of bulk quantities between Hawaii and the mainland) estimates hazardous waste ocean transport and handling costs to be roughly \$90/ton (Thayer 1993). Thus, total disposal costs for bulk shipment would be about \$253-\$370/ton.

Nonhazardous waste disposal in an RCRA Subtitle D landfill in Hawaii would run about \$55-\$60/ton (including transportation), and other landfill options would cost less (see Section 3.3.2.1).¹¹ Thus, disposing of coal ash determined to be hazardous could cost up to roughly 100 times as much as waste determined to be nonhazardous.

Added to the high economic costs associated with U.S. mainland disposal of hazardous waste are political costs. Western states have agreed to accept Hawaiian hazardous waste, but only if the state consciously tries to stem hazardous waste generation (Harder 1993). Adding significant quantities to the amounts already accepted by these western states could jeopardize the agreement. Current arrangements would therefore limit the feasibility of shipping Hawaii-generated hazardous coal combustion wastes to the mainland for disposal.

Hawaii solid-waste management officials indicate that near-term development of a Subtitle C hazardous waste treatment and disposal facility in Hawaii is unlikely. The state has no moratorium on building such facilities, but developers have been unable to propose economically feasible hazardous waste facilities. The small volumes of hazardous waste generated cannot support the economies of scale needed to efficiently operate such a facility.

¹⁰ Analytical testing determines the need for stabilization, which could be required if lead or cadmium, for example, had leaching potential. The estimated costs do not include an up-front flat fee of \$300-\$500 for analytical testing.

¹¹ Based on a \$54/ton tipping fee at the Subtitle D-approved landfill (Harder 1993) and \$0.09-\$0.10/ton-mi shipping costs (McCormick 1993).

It is possible that large volumes of coal waste could justify developing a hazardous waste disposal facility; but more information on specific volumes, treatments required, geologic conditions (water tables; earthquake potential), liner availability and requirements, etc., would be needed to make even preliminary proposals. In addition to economic issues, waste disposal facility developers face strong opposition from environmental and public interest groups.

By assuming that the economic, political, and emotional obstacles could be overcome and that a Subtitle C treatment and disposal facility were to be built in Hawaii, disposal costs may approach those paid elsewhere in the country. A May 1991 EPA report presented a representative range for disposing of one 55-gal drum of hazardous waste of between \$230 and \$1,265 (EPA 1991a). By assuming that one drum is about one-half of a cubic yard and that the average density of coal combustion wastes is 85 lb/ft³, a reasonable range for disposing of coal ash wastes in an RCRA Subtitle C facility in Hawaii would be about \$400-\$2,200/ton. For bulk disposal, Chemical Waste Management estimates costs in the \$120/ton range, excluding shipping and handling. The tremendous range in these estimates reflects the unknowns associated with construction requirements, land availability, land cost, geologic conditions, political uncertainties, etc.

3.3.2 Disposal Options and Issues Associated with a Nonhazardous Waste Determination

If coal combustion wastes are determined to be nonhazardous, they will be managed (as they are currently) according to RCRA Subtitle D, which delegates administration to the states. The Hawaii Code of Rules and Regulations, Title 11, Chapter 58 (1981), contains Hawaii's solid waste rules. The state is revising these rules to (1) include permit requirements and standards for solid waste disposal facilities that comply with federal minimum criteria for MSW landfills,¹² and (2) streamline recycling and reclamation provisions.¹³ Hawaii Department of Health representatives note that, pending federal action, coal combustion wastes will be managed as special wastes.¹⁴ The Hawaiian overall objective for special waste management is reuse, rather than disposal. Hence, rather than drafting detailed special waste disposal requirements, the state will determine management requirements on a case-by-case basis.

¹² On October 9, 1991, the EPA promulgated final rules on Solid Waste Disposal Facility Criteria (40 CFR Part 258), which include location restrictions, facility design and operating criteria, groundwater monitoring requirements, corrective action requirements, financial assurance requirements, and closure and postclosure care requirements for MSW landfills (EPA 1991b).

¹³ State officials anticipate enactment of the revised rules in the fall of 1993.

¹⁴ Other special wastes include sewage, lead acid batteries, scrap tires, and municipal incinerator ash.

3.3.2.1 On-Island Disposal

With no rules specifically addressing coal combustion wastes in Hawaii, recently issued permits for facilities that generate similar wastes may serve as models for coal combustion waste management requirements. These similar wastes include combustion wastes from the existing AES fluidized-bed combustor, which are to be reused, and large volumes of incinerator ash from MSW incinerators (disposed of in landfills).

In late 1992, the state of Hawaii issued a recycling activity permit for waste management at the AES AFBC power plant. Under this permit, all of the wastes generated from this facility are to be used in one or more of the following applications: as an aggregate substitute in lightweight concrete or road subbase, as a cement additive, or as a soil amendment — either alone or in combination with sludges or "green" wastes (from composting). The permit requires testing and demonstration results before implementing any of these options, and the proposed application must meet any product specifications of the Hawaii Department of Transportation or recognized engineering societies. Hawaiian solid-waste officials note that these tests are often more strict than the RCRA hazardous wastes tests; for example, for any soil application use, standards of the Waste Water Branch would need to be met. (Other applications of coal combustion wastes are described in Section 3.4.)

Municipal solid-waste incinerator ash is treated as a special waste requiring disposal in a monofill (a landfill containing waste from only one source) or, with a variance and assurance that operational problems would not be created, in a monocell (a cell within an MSW landfill). Two MSW incinerators operate in Hawaii: one is a waste-to-energy plant that produces about 180-200 tons of ash per day and uses a monofill collocated with the MSW landfill. The other is a smaller facility with no energy-generating capability, the ash from which is commingled with other wastes in the MSW landfill.

If coal combustion waste reuse opportunities in Hawaii were limited (because of regulatory hurdles, insufficient markets, unsuitability of specific wastes for specific applications, etc.), other disposal methods (i.e., landfill options) would be evaluated. According to John Harder (1993), Manager of the Department of Solid Waste within the Hawaii Department of Health, specific landfill options would depend on the results of tests (e.g., the TCLP) indicating degree of hazard. Depending on TCLP test results, Hawaiian disposal scenarios could include the following:

- *Construction and debris (C&D) landfill.* If the wastes were found to be essentially inert, the generator could receive a permit to dispose of the wastes in a C&D landfill, which, because it does not require liners or other costly environmental protection controls, would be the least costly landfill option. The island of Oahu has a C&D landfill, which charges a tipping fee of \$150/20-yd³ truckload. Assuming a coal combustion waste density of 85 lb/ft³, the disposal costs per ton at the C&D landfill would be about \$6.50.

- *Municipal solid-waste landfill.* If the TCLP showed that the wastes contained materials consistent with those allowed in MSW landfills, the wastes could be codisposed of with other wastes in a Subtitle D-approved MSW landfill.¹⁵ The viability and cost of this option would depend on existing and developable landfill capacity. Constraints on new MSW landfill development include perceived lack of space, the not-in-my-backyard (NIMBY) syndrome, and other perceived environmental issues. Nonetheless, Hawaiian political and geographic conditions may make siting of additional facilities easier than in many other states. In Hawaii, each island is a separate county responsible for providing sewage, waste collection, power, and other services to its residents. Counties do not share these services. Therefore, if the citizens understand that landfill development is a necessary component of providing electricity and if residents of other islands will use neither the electricity nor the landfill, siting may be easier than on the mainland, where economic and environmental boundaries are less distinct.
- *Monocell in a municipal solid-waste landfill.* Under current Hawaiian solid waste management policy and proposed revisions to Hawaiian solid waste regulations, test results may indicate that coal combustion wastes exhibit certain characteristics (e.g., reactivity) that would require the wastes to be buried separately from other materials within a given landfill. Costs for this type of disposal would be somewhat higher than for straight codisposal in an MSW landfill.
- *Monofill built specifically for coal combustion wastes.* This type of disposal would be appropriate for coal combustion wastes requiring less stringent control than required under the new Subtitle D MSW landfill regulations; for example, under current Hawaiian waste management policy and proposed revisions to Hawaiian solid waste management regulations, coal combustion wastes may be subject to some minimal permeability requirements and, depending on the location, some groundwater monitoring, but probably no air emissions monitoring. For such a monofill to be permitted, the Hawaii Department of Health would have to approve the design, but it is possible that some designs would provide lower disposal costs than some of the previous alternatives. Section 3.3.3 estimates costs associated with various coal-only waste disposal scenarios.

¹⁵ A Subtitle D-approved landfill is one that meets the Solid Waste Disposal Facility Criteria as promulgated by the EPA on October 9, 1991 (EPA 1991b). One such facility exists in Hawaii, and it charges \$54/ton.

An important factor in determining landfill disposal costs is not only the tipping fee, but also the transportation costs. By assuming an average transportation cost of \$0.09-\$0.10/ton-mi (McCormick 1993) and a hauling distance from the utility to the Hawaiian landfill ranging from 10 to 30 mi, transportation costs could add about \$1-\$3/ton of coal wastes disposed of in a landfill. These costs make off-site disposal more costly than on-site disposal. According to a recent DOE report on management of coal combustion wastes, about 72% of existing disposal units are collocated with the utility, and off-site disposal is only selected when land for on-site disposal is not available (ICF Resources Inc. 1993).

Another consideration for landfill disposal is the time required to obtain a permit. By assuming no significant political or community opposition, planning a new disposal site takes about two to three years and an additional two to three years for design and construction (ICF Resources Inc. 1993). Because the volumes of coal combustion wastes are so high, utilities must plan for alternative methods of waste disposal while the disposal facilities are being built.

3.3.2.2 Off-Island Disposal Options and Issues

This section describes issues associated with three options for off-island disposal: shipment to the U.S. mainland, shipment to other countries, and ocean disposal.

Shipment to the U.S. Mainland. Key considerations in shipping coal combustion wastes to the U.S. mainland are legislative and economic. The existing hazardous waste compact between Hawaii and the western United States would not affect shipments of nonhazardous coal ash; however, any congressional action restricting interstate shipment of MSW, while not directly affecting the viability of shipping coal wastes to the U.S. mainland, could set a precedent restricting interstate shipments of other types of waste, including nonhazardous coal combustion wastes.

Costs to transport nonhazardous coal wastes to the U.S. mainland consist primarily of shipping costs (including loading and unloading) and tipping fees (per-ton charges paid to the ultimate disposal facility). A representative of Waldron Steamship Company, Ltd., which ships bulk loads between Hawaii and the mainland, estimates that shipping costs would average \$32-\$50/ton of ash, depending on ship size and backhaul potential, and that handling costs would be about \$5/ton at each end, for a total of \$42-\$60/ton (Thayer 1993).¹⁶ At \$0.09-\$0.10/ton for mainland transport (shipment from the dock to the ultimate disposal facility) and with a distance of 10-50 mi between the dock and the disposal facility, land shipment costs would add another \$1.00-\$5.00/ton. (By assuming that the utility is close enough to the dock, additional transportation costs would not be incurred to haul the coal

¹⁶ Shipping costs, by assuming no backhaul and excluding handling, are about \$40/ton if the coal ash fills a 10,000-ton ship and about \$50/ton if it fills a 30,000-ton ship. Costs would drop about 20% if there were a backhaul.

from the utility to the dock.) Tipping fees at the landfill could range from about \$15 to \$55/ton (Sheets and Repa 1991). Thus, total estimated costs for mainland disposal are \$58-\$120/ton. These estimates are rough and depend on a variety of factors, including season, availability of ships, time in port, frequency of shipments, size of ship, and vessel origin.¹⁷ Tipping fees vary with specific location, volume, and capacity and could increase if Congress passed legislation allowing states to charge differential fees for imported wastes (see Section 3.3.1.2).

The Shore Protection Act of 1988 (SPA 1988) provides for additional ocean shipping requirements, but these requirements would not significantly impact waste shipment. The act requires any vessel that transports municipal or commercial wastes in coastal waters to have a special U.S. Coast Guard permit.¹⁸ Currently, acquiring this permit is relatively simple: the vessel's owner or operator writes a letter to the U.S. Coast Guard requesting such a permit, and the U.S. Coast Guard returns the letter with a permit stamp on it; however, the EPA is currently drafting permit regulations that include a requirement for each vessel and transfer station to have an operations and maintenance manual (essentially an emergency response plan). The EPA plans to propose this regulation in June 1993 and to promulgate the final regulation about a year later. Compliance with these rules is not expected to cause significant cost or manpower burdens on vessel operators.

Shipment to Other Countries. Utility owners and operators may want to ship nonhazardous coal combustion by-products to other countries for two purposes: beneficial use applications and disposal. Ash marketers indicate that some Pacific countries (e.g., Taiwan) want to import coal combustion by-products for construction. These countries burn coal and generate coal combustion wastes; however, the constituents of the coal burned are often variable, resulting in by-products of inconsistent quality. Such by-products have limited use for many beneficial use applications. Because coal combustion wastes generally substitute for other relatively low-cost materials, such exports should be considered as cost-reducing, rather than revenue-generating, measures. International agreements allow export of combustion by-products for beneficial applications, but efforts to limit transboundary waste shipments should be monitored for export implications (see Section 3.3.1.2).

Countries not in the market for usable coal combustion by-products may be willing to import them for waste disposal; however, the Basel Convention may limit disposal

¹⁷ The next section estimates costs for shipping wastes to Taiwan, a country that has expressed interest in receiving coal ash. Even though Taiwan is further from Hawaii than the mainland is, the costs to ship to Taiwan are lower for the same size vessel because only U.S.-flagged vessels are allowed to transport goods from one U.S. state to another (U.S. law prohibits foreign carriers from shipping between U.S. ports). With everything else equal, non-U.S.-flagged vessels charge less than U.S.-flagged vessels. Shipping experts attribute the lower costs of foreign-vessel shipping to greater competition and newer, more efficient ships.

¹⁸ Although not specified in the law, EPA staff suggests that coal combustion wastes would be considered as municipal waste (Salter 1993).

opportunities. Any party to the Basel Convention may declare a specific waste to be hazardous, even if the exporting country determines that waste to be nonhazardous. Once a waste is declared hazardous, it must be managed according to the rules and regulations of the party that has determined it to be hazardous. Also, many countries, including Indonesia, have enacted laws prohibiting waste imports (see Section 3.3.1.2). Thus, the waste import status of candidate disposal countries should be clearly determined.

Cost is an important factor in shipping to other countries. Because non-U.S.-flagged vessels may ship cargo from a U.S. port to a non-U.S. port (only U.S.-flagged vessels may ship from one U.S. port to another), shipping to a foreign port can cost less than shipping to a U.S. port. Pacific Rim Shipbrokers, Inc., estimates freight costs of \$27-\$42/ton (depending on ship size and backhaul potential), plus \$5/ton for handling at each end, for a total of \$37-\$52/ton (Hall 1993).¹⁹ These costs do not include transportation costs or tipping fees in the foreign country. Information on such costs is variable and requires further study.

Ocean Disposal. Given the current national and international regulatory climates, obtaining an ocean disposal permit for coal combustion wastes would be difficult, even if they were determined to be nonhazardous. As noted in Section 3.3.1.2, the LC currently restricts ocean disposal of hazardous wastes; and, once amended, the LC will further limit ocean disposal options. Many parties to the LC have voluntarily agreed to a moratorium on ocean disposal of commercial wastes. Parties to the LC are moving toward an outright ban on dumping, and it is expected that this moratorium will be made a permanent provision of the convention (Witt 1993).

The MPRSA has already banned dumping of certain nonhazardous wastes at sea. Section 1414(b) prohibits dumping industrial wastes or sewage sludge into ocean waters after December 31, 1991. According to EPA staff, even though the definition of industrial wastes neither explicitly includes nor excludes coal combustion wastes, such wastes would most likely be considered industrial wastes, and therefore the MPRSA would prohibit ocean disposal of these wastes (Redford 1993).²⁰ In the unlikely event that coal combustion wastes were somehow considered nonindustrial wastes, obtaining an ocean disposal permit would be a long, arduous, and, most likely, ultimately unsuccessful process. Permit applicants must obtain disposal site approval from the EPA (a two-year \$2-million process), undergo a lengthy public participation process (with a public that is environmentally conscious and protective of its oceans), prepare an environmental impact statement, and endure several years for the overall process. Even if the utility owner or operator decided to procure a permit under these

¹⁹ Estimated shipping costs with the assumption of no backhaul and excluding handling are about \$42/ton if the coal waste fills a 10,000-ton ship and about \$35/ton if it fills a 30,000-ton ship. With a backhaul, the 10,000-ton load would cost \$35/ton, and the 30,000 load would cost about \$27/ton.

²⁰ Industrial waste in the MPRSA is defined as any solid, semisolid, or liquid waste generated by a manufacturing or processing plant, other than an excluded material [Section 1414 (k)(4)]. (Excluded material refers to dredged materials and tuna cannery operations for which permits have been granted.)

conditions, the coal combustion wastes would most likely fail the required EPA criteria of the ocean disposal regulations regarding testing of the material (e.g., bioassay tests) and would be denied a permit on these grounds alone (Redford 1993). Officials at the EPA stress that the agency does not look favorably upon ocean dumping and offers prospective applicants no encouragement (Witt 1993). Worth noting is that prior to the Ocean Dumping Ban Act, a few utilities had applied for ocean disposal permits, but the EPA either denied or has since rescinded all of these permits (Redford 1993; Cotter 1993).

3.3.3 Disposal Options, Issues, and Costs Associated with a Special-Category Waste Determination

It is possible that coal combustion wastes could be regulated under a special category of wastes that is neither hazardous as defined under RCRA Subtitle C nor nonhazardous as currently provided for under RCRA Subtitle D. In this case, coal combustion wastes would be treated as industrial nonhazardous wastes, with disposal criteria or regulations (or both) to be developed by the EPA. Such a classification could apply to either or both of (1) the high-volume wastes recently exempted from RCRA Subtitle C according to the EPA's August 9, 1993, regulatory determination and (2) the CCT wastes, for which a regulatory determination is due in April 1998. The August 9 regulatory determination specifically states that the EPA will consider the four high-volume wastes (fly ash, bottom ash, boiler slag, and FGD wastes) during its ongoing assessment of industrial nonhazardous wastes under RCRA Subtitle D (EPA 1993). The EPA has been assessing industrial nonhazardous wastes, which include wastes from petroleum refining, from pulp and paper manufacturing, and from chemical manufacturing, for several years and plans to continue this assessment. Although the EPA has neither projected any date for issuing regulations or criteria for disposing of these wastes, nor suggested the types of controls it would require, recently promulgated rules for MSW landfills that set a precedent for such regulation. These rules lay out certain requirements for MSW landfills, which, while not as strict as Subtitle C requirements, do impose additional costs on disposal in MSW landfills.²¹ In addition, several states have implemented specific requirements for coal combustion waste management, and these rules provide examples of how federal regulations may look. This section summarizes state activities to regulate coal combustion wastes, possibilities for increased federal regulations, and potential regulatory costs.

3.3.3.1 State Regulation of Coal Combustion Wastes

In its 1988 report to Congress, the EPA included the results of a 1983 survey of coal combustion waste disposal regulations in 50 states. In 1991, the EPRI updated the survey for 11 major coal-burning states (ICF Resources Inc. 1993). Of these states, 10 had stricter

²¹ In October 1991, the EPA promulgated municipal landfill regulations to be implemented by individual states by October 1993. These regulations encompass six categories: location restrictions, operating requirements, design standards, groundwater monitoring and corrective action, closure and postclosure, and financial assurance (EPA 1991b).

requirements in 1991 than in 1983. Four of these states now require testing of coal combustion wastes for hazardous characteristics; one state required tests in 1983. Examples of current requirements include liners (some states specify numbers and types of liners), leachate control, groundwater monitoring, and closure requirements. Clearly, the trend is toward stricter regulation of coal combustion wastes.

3.3.3.2 Possible Federal Regulations

Estimating the nature and extent of potential federal regulations for coal combustion wastes is a matter of conjecture; however, recent state experience and studies conducted in conjunction with RCRA reauthorization suggest that new coal combustion waste disposal facilities could be required to provide one or more of the following: double liners, leachate collection systems, groundwater monitoring, and closure plans.

3.3.3.3 Potential Costs

The Utility Solid Waste Activities Group (USWAG) within the Edison Electric Institute (EEI) commissioned a study in 1991 that estimated construction and closure costs associated with various design scenarios that it postulated the EPA could impose on coal waste disposal facilities (Cook-Joyce, Inc. 1991). The study estimated costs for four power plant design capacities (500; 1,000; 1,500; and 2,000 MW) and two coal ash contents (10% and 20%). Assumptions included the following:

- A 65% load factor over a 35-year plant life,
- Energy content of 10,000 Btu/lb of coal,
- FGD technologies in common operation today, and
- Waste recovery and reuse rate of 25%.

The study estimated costs per ton for four design scenarios:

1. A base case, which represents the simplest and least costly method of containment that a utility could use in today's regulatory climate. This scenario assumes favorable geologic conditions and native soils that are recompacted for liner material.
2. An intermediate design typical of some state requirements for industrial solid wastes and used by some coal combustion waste management units where geologic conditions are unfavorable. It uses a 3-ft clay liner.
3. An intermediate design that uses significantly more stringent criteria and is not typically used for coal waste management except where

geologic or hydrogeologic conditions are poor. This design uses a 3-ft clay liner and leachate collection system.

4. A Subtitle D design, which reflects the USWAG's judgment of the most stringent facility design requirements that federal legislation would impose. This scenario assumes a composite liner²² system with a leachate collection system and corresponds to the design requirements for MSW landfills as defined in the EPA's 1991 "Solid Waste Disposal Facility Criteria" (40 CFR 258.40) (EPA 1991b).

Table 3.1 presents cost estimates for each of the four design scenarios and for the three (of the 10 USWAG) operating scenarios that most closely reflect the demands of the Hawaiian market.²³

- 500-MW power plant capacity, 10% coal ash, wet fly-ash/FGD material handling system, and wet bottom-ash handling system — denoted as "500-MW Wet" in Table 3.1;

**TABLE 3.1 Estimated Construction and Closure Costs
for Subtitle D Disposal Scenarios**

Design Scenario	Estimated Costs per Ton of Waste (dollars)		
	500-MW Wet	500-MW Dry	1,000-MW
1. Base case	2.20	1.41	1.43
2. Compacted clay liner	4.89	3.47	3.27
3. Compacted clay liner/leachate collection	6.73	4.72	4.43
4. Subtitle D (composite liner/leachate collection)	6.80	4.72	4.63

Source: Cook-Joyce, Inc. (1991).

²² According to the EPA, a composite liner has two components: an upper component of flexible membrane liner (at least 30 mil) and a lower liner of at least 2 ft of compacted soil with a hydraulic conductivity of no greater than 1×10^{-7} cm/s [40 CFR 258.4(b)].

²³ Of the remaining seven scenarios, five assume coal ash content of 20% (as opposed to 10%), and the other two assume large generating capacities (1,500 and 2,000 MW).

- 500-MW power plant capacity, 10% coal ash, dry fly-ash/FGD material handling system, and wet bottom-ash handling system — denoted as "500-MW Dry" in Table 3.1; and
- 1,000-MW power plant capacity; 10% coal ash; and dry fly ash, wet bottom ash, and wet FGD material handling systems — denoted as "1,000-MW" in Table 3.1.

Table 3.1 shows that the costs of implementing Subtitle D design requirements range from about \$3/ton for a 1,000-MW plant under the compacted liner scenario to about \$7/ton for a 500-MW plant with a wet FGD scrubber under a full Subtitle D scenario (composite liner and leachate collection system). These costs represent estimated annualized construction and closure costs per ton of coal waste produced and do not include incremental costs of RCRA operational requirements such as groundwater monitoring, facility operations, corrective action requirements, financial assurance, and closure and postclosure care. A rough estimate of these costs can be derived from the EPA's cost and economic impact analysis conducted for the MSW landfill rules. This analysis estimated that the average additional costs for complying with selected options were \$1/ton for a "limited approach" (locational restrictions, groundwater monitoring, and corrective action) and \$2/ton for a full Subtitle D approach (EPA 1991b, p. 50986). Assuming that the limited approach excludes construction and closure costs, the \$1/ton cost of the limited approach is a rough approximation of these additional RCRA operating requirements. Adding \$1/ton to each of the costs for scenarios 2 through 4 in Table 3.1 results in a range of disposal costs for the special category of between \$4/ton and \$8/ton. Adding these costs to the current industry average coal waste disposal costs of \$10-\$15/ton and adding transportation costs of \$1-\$3/ton²⁴ result in estimated special nonhazardous waste category compliance costs ranging between \$15/ton and \$26/ton. Actual costs will depend on design requirements, size of power plant, combustion technologies, waste-handling methods, and hydrogeologic conditions of the disposal sites.

While economies of scale may lower per-ton costs for larger amounts of waste, advanced coal technologies can produce more waste per ton of coal burned than conventional technologies. Thus, while per-ton disposal costs may decrease as more waste is produced, total costs may increase. Additional economic analysis would be required to determine if economies of scale could compensate for the increased amounts of clean coal wastes requiring disposal.

3.3.4 Cost Estimates: Summary

Significant variability is found in the costs associated with various coal combustion waste management options. The most costly option assumes that the EPA will determine

²⁴ On the basis of a hauling distance of 10-30 mi and average transportation costs of \$0.09-\$0.10/ton-mi.

CCT wastes to be hazardous and that the utility would have to ship these wastes to the U.S. mainland for disposal at a cost of \$250-\$370/ton. These costs can be compared with the industry average by-product management costs of \$10-\$15/ton. Table 3.2 summarizes the costs for various options, and Table 3.3 provides additional detail. These estimates are rough and would require additional refinement as utility owners and operators investigate specific options; for example, costs should be developed on the basis of detailed estimates from several waste management companies and different disposal locations, as well as on the basis of estimates to develop various nonhazardous and hazardous disposal facilities in Hawaii.

3.4 POTENTIAL USE OF COAL COMBUSTION WASTES OR BY-PRODUCTS IN HAWAII

Coal combustion by-products have been increasingly used in various applications since the 1940s. The ACAA reports that utility and other industrial applications consumed about 22 million tons of coal combustion and FGD by-products or about 25% of the 90 million tons generated. The remainder went to disposal. The most common combustion by-product

**TABLE 3.2 Summary Cost Comparisons
for Coal Combustion Waste Management Alternatives**

Combustion By-Product Determination and Management Alternative	Cost per Ton (dollars)
Hazardous determination	
U.S. mainland disposal	230-370
Nonhazardous determination	
On-island MSW landfill	55-57
On-island C&D landfill	8-10
Off-island — mainland U.S. landfill	58-120
Special nonhazardous determination	
On-island	15-26
Off-island — mainland U.S. landfill	57-88
Beneficial application	(0-15) ^a
U.S. industry average disposal costs	10-15

^a Parentheses indicate that revenues are generated by utility. Coal waste application with greatest revenue-producing potential is as cement substitute in concrete production; concrete manufacturers will pay around \$15/ton (Golden 1993). Other applications, to the extent that they net any revenue at all, would most likely yield less than \$15/ton.

**TABLE 3.3 Breakdown of Summary Cost Comparisons
for Coal Combustion Waste Management Alternatives**

Combustion By-Product Determination and Management Alternative	Cost Component per Ton (dollars)			
	Disposal	Transport	Other	Total
Hazardous determination				
On-island disposal	-	-	-	NA ^a
Off-island — U.S. mainland disposal	124 ^b	129 ^c	0-117 ^d	230-370
Off-island — foreign disposal	-	-	-	NA ^e
Nonhazardous determination				
On-island MSW landfill	54 ^f	1-3 ^g	-	55-57
On-island C&D landfill	7 ^h	1-3 ^g	-	8-10
Off-island — U.S. mainland landfill	15-55 ⁱ	32-50 ^j	11-15 ^k	58-120
Off-island — foreign disposal	-	-	-	NA ^e
Special nonhazardous determination				
On-island	14-23 ^l	1-3 ^g	-	15-26
Off-island — U.S. mainland landfill	14-23 ^l	32-50 ^j	11-15 ^k	57-88
Off-island — foreign disposal	-	-	-	NA ^{e,m}
Beneficial application				
Substitute for cement in concrete	-	-	-	(15) ⁿ
Ash rock for fill	-	-	-	(6) ⁿ
Other applications	-	-	-	<15
U.S. industry average disposal costs	-	-	-	10-15 ^o

^a NA, Not available. No hazardous waste sites exist in Hawaii, and none are projected to be built. Hazardous waste disposal costs range from about \$113-\$2,200/ton in U.S. mainland (EPA 1991a; Farrel 1993).

^b Includes 10% county hazardous waste disposal tax.

^c Consists of \$90 for ocean transport (Thayer 1993) and \$39 for land transportation (Farrel 1993).

^d Stabilization fee (need for stabilization depends on analytical testing results). Estimate does not include one-time \$300-\$500 fee for analytical tests.

^e Cost estimates for foreign hazardous waste disposal are not readily available. Many countries prohibit importation of hazardous waste for disposal. Estimating foreign waste disposal costs would be subject of separate study.

^f Current tipping fee at Oahu MSW landfill. (This landfill meets Subtitle D solid waste disposal facility criteria promulgated by EPA [1991b]).

^g On basis of transportation costs of \$0.09-\$0.10/ton-mi and distance between utility and disposal site of 10-30 mi.

^h On basis of current disposal costs at Oahu C&D landfill of \$150 per truckload, 20 tons per truck, and coal combustion by-product density of 85 lb/ft³.

ⁱ Sheets and Repa (1991).

^j Lower end of range assumes backhaul; higher end assumes no backhaul (Thayer 1993).

^k Includes \$5/ton at each end of ocean transport for handling and \$1-\$5/ton for mainland transportation (on basis of \$0.09-\$0.10/ton-mi and assumed distance of 10-50 mi).

^l Includes construction and closure costs of \$3-\$7/ton and RCRA operating requirements of \$1/ton, added to industry-wide average coal waste management costs of \$10-\$15/ton.

^m Several countries prohibit wastes (regardless of hazard) for disposal.

ⁿ Parentheses indicate that revenues are generated by utility. Existing 180-MW AES plant has sold combustion by-products as manufactured aggregate called "ash rock" to local contractors for use as subbase material for up to \$6/ton. Coal waste application with greatest revenue-producing potential is as cement substitute in concrete production; concrete manufacturers will pay around \$15/ton (Golden 1993). Other applications, to the extent that they net any revenue at all, will most likely yield less than \$15/ton.

^o Roewer (1993).

applications today are cement and concrete production, structural fill, and road base and subbase construction; potential applications that have not been implemented to a significant degree at the commercial level but appear to hold promise include waste stabilization, agricultural amendments, paints and coatings, plastic filler material, and artificial reefs.

Coal combustion by-product management costs and requirements depend largely on whether these products are considered wastes or other (i.e., recyclable) secondary materials. A waste classification implies complying with increasingly costly national and international transportation and regulatory constraints.²⁵ Such a classification also restricts the use of coal combustion by-products: waste treatment facilities face political and emotional roadblocks, such as the NIMBY syndrome. Furthermore, many industrial facilities that could substitute secondary materials for virgin materials may be unwilling or unable to incur the cost and trouble of obtaining necessary waste use permits. The question of whether coal combustion by-products are wastes or secondary materials is far from being resolved, both in the United States and abroad (Smith and Sarnoff 1992).

Not having to comply with waste management rules and regulations is important for two key reasons:

1. Waste management costs are increasing. Causes of these increases include stricter disposal area siting, construction, and management requirements, as well as increased permitting difficulties because of the NIMBY syndrome.
2. Coal combustion waste quantities are increasing because of the increasing use of coal and the commercial application of CCTs, many of which generate more waste per megawatt of capacity than conventional coal-burning technologies.

Waste disposal costs money. Any costs avoided or revenues generated by using these materials will offset operating costs and should be considered as valuable as revenues generated from power sales.

The remainder of this section discusses the beneficial applications for coal combustion by-products (Section 3.4.1), characteristics of CCT wastes that may affect by-product application (Section 3.4.2), and conditions that may enhance or reduce the ability to implement these applications in Hawaii (Section 3.4.3).

²⁵ Waste disposal costs are increasing at about 10% per year, and correlated with these increasing costs are increasingly stringent environmental regulations (Weissman and Sekutowski 1992).

3.4.1 Uses of Combustion Wastes

This section describes existing and potential uses for coal combustion by-products (Section 3.4.1.1) and FGD sludge (Section 3.4.1.2). Statistics on coal by-product production and use come from the ACAA (undated).

3.4.1.1 Combustion By-Product Applications

Of the three coal combustion by-products, fly ash is the most widely produced. The ACAA (undated) reported that, in 1991, coal-fired utilities produced about 51 million tons of fly ash or 73% of all coal combustion wastes produced in that year. Of the 51 million tons, 13 million (25%) were consumed. In 1991, utilities produced about 13 million tons of bottom ash (with a utilization rate of about 38%) and about 6 million tons of boiler slag (with a utilization rate of about 60%). Table 3.4 summarizes quantities used in the major applications in 1991, and the following paragraphs describe specific uses of coal combustion by-products.

TABLE 3.4 Coal Combustion By-Product Use in 1991 (millions of tons)

Application ^a	Fly Ash	Bottom Ash	Boiler Slag	Subtotal	FGD Material
Cement and concrete products	7.8	0.7	0.3	8.8	0
Structural fills	2.5	0.8	0.3	3.6	0
Road base and subbase	1.0	0.7	0.1	1.8	<0.1
Blasting grit/roofing granules	0	<0.1	2.0	2.1	0
Snow and ice control	<0.1	1.0	0.5	1.6	0
Grouting	0.2	0	0	0.2	0
Mineral filler in asphalt	0.1	<0.1	<0.1	0.3	0
Coal mining	0.2	0	0	0.2	0
Waste stabilization	0.4	0	0	0.4	0
Wallboard	<0.1	0	0	<0.1	<0.1
Miscellaneous/other	1.0	1.6	0.2	2.8	0.2
Total ^b	13.2	5.0	3.6	21.8	0.3

^a Includes both external market and internal utility applications.

^b Totals may not sum due to rounding.

Cement and Concrete. Most fly ash exhibits pozzolanic properties (i.e., the ability to form stable insoluble compounds with cementing properties when combined with lime and water). Fly ash can replace natural clays or shales in the production of portland cement; and depending on the quality of the fly ash and the desired performance characteristics of the concrete, fly ash can replace up to 50% of the cement component in concrete (Horn 1988). Fly ash concrete is used in mass concrete applications (e.g., dams), roads, and bridges and as a partial replacement for portland cement in concrete to build foundations, airfields, retaining walls, buildings, and wastewater treatment facilities. Researchers are testing fly ash as a substitute for the sand feedstock to produce autoclaved cellular concrete blocks. These blocks are lightweight, fire-resistant, sound-absorbing, insect- and rot-resistant, and easily workable (the material can be cut with a hand-held or circular saw).

In 1991, about 8 million of the 51 million tons of fly ash generated were used in cement and concrete production. Benefits of using fly ash over natural materials in cement and concrete include the following:

- *Energy savings.* Cement production is energy-intensive. Already fired and finely divided, fly ash can reduce total energy use in cement production by about 15% (EPA 1983). Also, expanding existing cement and concrete production capacity by using fly ash is less expensive (\$5-\$15/ton for added capacity) than building new kilns (\$125-\$185/ton for a new cement plant) (EPA 1983).
- *Enhanced workability.* Small particle sizes and spherical shapes make fly-ash concrete easy to handle.
- *Higher final strength of material.*
- *Reduced water requirements.* Less water leads to a more durable surface.
- *Increased resistance to sulfate infiltration* (because of lower permeability).
- *Lower heat of hydration.* Water reacts slowly with fly ash, minimizing potential heat release problems in large structures.
- *Suitability for lightweight specialty concretes* (because of low particle density.)
- *Suitability for flowable or pumped concretes* (which are widely used in high-rise building construction).

A variety of standards, including those specified by the American Society for Testing and Materials (ASTM), the National Highway Cooperative Research Program, the Federal Highway Administration, the Corps of Engineers, and the American Concrete Institute, control the quality of cement and concrete containing fly ash. Conformance with these

specifications should help allay concerns about the performance of fly-ash cement and concrete, compared with more traditional cement and concrete.

The U.S. legislative and executive branches have both provided impetus for using cement and concrete containing fly ash. Section 6002 of the RCRA requires certain items purchased with federal funds to contain the highest percentage of recovered materials practicable and requires the EPA to develop guidelines on the procurement of those materials. In January 1983, the EPA published guidelines on concrete and cement containing fly ash that are applicable to federal, state, and local agencies (48 FR 4230), in which the EPA suggested that the expected cost savings would increase the use of fly-ash cement and concrete in nonfederally funded construction as well. Although separating the influence of the RCRA requirement from other factors is impossible, fly ash use has increased, as shown in Table 3.5.

Former President Bush provided further impetus for fly ash use in federally funded activities when he signed Executive Order 12780, "Federal Agency Recycling and the Council on Federal Recycling and Procurement" (56 FR 56289), on October 31, 1991. This order requires federal agencies to develop and implement procurement preference programs for recycled materials and to report annually to the EPA on the effectiveness of the procurement programs.

Fill Material. Fly ash and bottom ash are widely used as structural fill where availability and transport distances make natural materials less competitive. Common uses include embankments and structural fills for airport runways and building sites. Coal combustion by-products can also replace extracted materials in old quarries and gravel pits and restore land to acceptable contours. Recently developed applications of fly ash in fill include controlled-density fill and "flash fill." Controlled-density fill combines cement, fly ash, sand, and water to yield a lightweight fill material that needs no compaction and is easier to excavate than concrete. "Flash fill," consisting of fly ash and water, is a fast-setting backfill that flows from a mixing truck and also requires no compaction (Bretz 1991).

Coal combustion by-products offer several advantages over competitive fill materials. These advantages include low unit weight, which makes handling easier; self-hardening properties (especially where a high free-lime content is found), leading to cohesive strengths greater than those in natural materials; greater slope stability than some soils (especially clayey soils); and negligible settlement (Dawson et al. 1987). In 1991, fill applications accounted for nearly 4 million tons of coal combustion by-products.

Road Construction. Coal combustion wastes are widely used in road and subbase construction, substituting for naturally occurring aggregates or acting as pozzolanic ingredients. Since the 1950s, road building has consumed over 30 million tons of coal combustion wastes for unstabilized base and subbase courses, as well as stabilized bases and paving mixtures (Collins 1992). An alternative technique for using fly ash in road construction combines fly ash and water in a landfill, where the material is left to harden.

The hardened material is then crushed, sized, and used to replace iron-ore gravel. The technique holds promise for regions where supplies of iron-ore gravel are limited. In 1991, utilities and other industries used almost 2 million tons of coal combustion by-products for road base and subbase applications.

Waste Stabilization. When mixed with lime, fly ash can solidify or fix other materials, thereby significantly decreasing potential leaching of metals and increasing the bearing strength of, and, hence, the ability to handle wastes so stabilized. Wastes stabilized with fly ash include FGD sludge, petroleum-laden soil, sewage sludge, incinerator ash, metals-processing wastes, acidic sludge, and low-level radioactive materials (Collins 1992). Soils stabilized with pozzolanic fly ash resist leaching into groundwater and therefore are good candidates for hazardous waste liner construction. Further study will help determine the physical and chemical durability of these liners. The ACAA reported that 400,000 tons of coal combustion ash were used in waste stabilization in 1991. While this amount represents less than 2% of total coal combustion by-product uses, the amount is significant, because this statistic is the first time the ACAA has reported any use of ash for waste stabilization.

Soil Amendments and Other Agricultural Applications. Researchers are studying the use of coal combustion wastes in agriculture to improve crop yield. Chemical benefits of applying coal combustion wastes to soils include Ph modification to enhance plant growth and supplying of essential plant nutrients to improve crop production. Chemical constituents in ash relate to coal type, source, and combustion technology; and of the eight major constituents found in most coal combustion wastes — calcium, iron, magnesium, potassium, silicon, aluminum, sodium, and titanium — the first five are important plant nutrients. Many coal combustion by-products are alkaline and therefore can help neutralize acidic soils. A variety of coal combustion by-products have been successfully used to modify soil Ph, and researchers expect that most coal ash agricultural applications will be for soil Ph modification (Korcak [undated]). Another chemical use of coal combustion wastes in agriculture relates to trace element constituents such as boron, selenium, arsenic, and molybdenum. While improper use can cause serious problems, carefully measured applications can help correct suboptimal concentrations of these elements (Korcak [undated]).

Physical benefits derived from using coal combustion wastes in agricultural soils include the following (Korcak [undated]):

- Improved soil texture and increased aeration (by applying silt-sized coal combustion by-products);

TABLE 3.5 Number of State Highway Agencies Routinely Using Fly Ash in 1983 and 1992

Application	1983	1992
Paving concrete	28	37
Structural concrete	12	34
Cement	18	20
Flowable fill	16	28

Source: Collins et al. (1993).

- Increased water use efficiency (by applying a cap of by-products that increases sustained infiltration rates, reduces evaporation losses from the soil surface, and increases rooting depth); and
- Early fruit bearing and reduced soil volume (by trenching pozzolanic coal combustion by-products into the soil, which prevents lateral root growth).

Specific benefits depend on the needs and condition of the soil and on the characteristics of the coal combustion by-products being applied. Coal waste characteristics depend on the coal burned and on the technologies used to burn the coal and reduce emissions. As noted by Ron Korcak (U.S. Department of Agriculture), optimal use of coal combustion by-products depends on how well characterized the by-products are prior to use (Korcak [undated]). Additional research will help answer questions about specific uses, potential hazards and mitigating measures, price competition with other materials, and long-term effects.

Roofing Granules and Sandblasting Grit. The durability, size gradation, and angularity of crushed boiler slag make it an appropriate material for surfacing the weather sides of asphalt roofing shingles. These characteristics, combined with the absence of small particles that can lead to respiratory health problems, make boiler slag good for sandblasting grit. In 1991, of the 5 million tons of boiler slag produced, almost 2 million tons was used as roofing granules or sandblasting grit. Bottom ash is also used for roofing and sandblasting.

Metals Extraction. Coal contains trace amounts of several metal oxides that are concentrated by burning. Physical, chemical, and magnetic technologies exist to recover the important metallic constituents of coal fly ash (aluminum, iron, and titanium). Electromagnets and proprietary processes have been used to extract up to 15% of the iron (by weight) in fly ash, and high-temperature chlorination may be used to extract titanium. Aluminum can also be recovered, but the processes are not yet economic. Many factors will influence the economics of extracting metals from coal ash, including international relations (e.g., 90% of the raw materials for U.S. aluminum production are imported), extraction costs, and marketing success (Dawson et al. 1987).

Grouting. For several years, fly ash has been used as a grouting material. Fly ash can be mixed with water only (especially if the ash is the cementitious class C fly ash derived from burning subbituminous coal) or with water and other materials to produce grout for mine subsidence control, soil stabilization, well casings, tunnel grouting, etc. Advantages of fly-ash grout include low cost, low permeability, low density, and low heat of hydration (Dawson et al. 1987). In 1991, utilities sold about 200,000 tons of coal combustion fly ash for grouting applications.

Aggregate. Fly ash can be combined with water (or wastewater treatment solids²⁶) to develop commercial-grade lightweight aggregates for use in concrete blocks and other lightweight structural concrete. Aggregate production plants are being built to use essentially all of the fly-ash output of some plants.²⁷

Abrasives. With minimal preparation, bottom ash can be used as a good-quality abrasive, especially because few, if any, specifications exist for blasting grit or abrasive. Fly ash can also be used for abrasives, if the particles are first agglomerated.

Coal Waste Artificial Reefs. Researchers have demonstrated the potential of artificial fishing reefs constructed with coal combustion by-products. The technique fixes ash from conventional coal combustion technologies with FGD sludge and cementing materials into hard solid blocks, which are then released into the ocean in an environmentally acceptable manner. In 1980, researchers at the State University of New York used 500 tons of coal combustion wastes fabricated into 15,000 blocks to build an artificial reef in 20 m of water off the southern coast of Long Island (New York State Energy Research and Development Authority 1985). During eight years of follow-up, field and laboratory data showed that exposure to seawater maintains or improves the structural integrity of the coal-waste blocks, and leaching does not appear to be significant (van der Sloot et al. [undated]). Researchers stress the importance of quality control standards to ensure success and stress that the coal type and technology affect suitability for stabilization and reef applications. Reef location is also important. To be an effective reef and not merely an alternative disposal site, the reef must be accessible to recreational fishermen, deep enough so that it does not affect navigation, and not interfere with commercial fishing trawlers (Dawson et al. 1987). The economics of coal-waste artificial reefs have not been commercially proven in the United States; however, research, development, and commercialization of these and related uses are ongoing in many countries. For example, Japanese researchers are studying fly-ash blocks for seaweed-breeding reefs (Omori 1991), Israelis are testing the feasibility of using coal combustion wastes to build an artificial island to expand the Tel Aviv city limits (Zimmels 1993), and Italian researchers are testing the feasibility and environmental compatibility of using coal combustion wastes to make an underwater reef for fish restocking in the Adriatic Sea (Sampaolo 1993).

²⁶ Wisconsin Electric Power is currently implementing this approach with wastes from the local municipal plant. The approach will allow marketing of 70% of the fly ash, compared with 14% now possible (Rittenhouse 1992).

²⁷ For example, Virginia Power Co. and Agglite Corp. plan to build a facility that will produce an aggregate from the ash generated by the 600-MW Chesapeake plant. The resulting spherical aggregate may be superior to angular, kiln-fired aggregate, because spherical material flows more readily, is more easily pumped, and is less abrasive. Savings are expected from the use of on-site raw materials that require no preprocessing (Reason 1989).

Gypsum. Some CCT wastes (e.g., those from fluidized-bed combustors) contain calcium sulfate (gypsum). Gypsum is used primarily in plaster and wallboard manufacture and, to a lesser degree, in cement (to retard setting). Commercial application of gypsum from fly ash is not widespread; there are other low-cost gypsum sources (including FGD sludges), and the gypsum market is limited.

Plastics. Because fly-ash particles are relatively hard and spherical in shape, they make good plastic filler material and act as a lubricating material for the plastic mix during extrusion. Current markets for fly-ash plastics include plastic pipe, automobile dashboards, screwdriver handles, patio furniture, football helmets, and bathtub/shower units (Bretz 1991). Boiler slag is also used as filler in fiberglass pipe, where the hardness of the boiler slag improves abrasion resistance and surface durability.

Paints and Coatings. Fly ash can replace talc as a mineral filler and can replace titanium dioxide as a pigment in paints and coatings. Demonstrations indicate that fly-ash paints last longer than paints with other fillers. Such paints are commercially used for floors, exterior walls, and engines.

Drainage Material. Drainage sites that need a free-draining medium, such as chimney drains or filters in major earth structures, can be well served with bottom ash and boiler slag. Often these materials are as effective as and less costly than the natural materials for which they substitute (Bretz 1991).

Mineral Wool. Mineral wool is similar to fiberglass and consists of lightweight fibrous materials used for insulation. Researchers have confirmed the technical feasibility of using coal combustion by-products for mineral wool manufacture and have indicated potential economic advantages. These advantages result because no mining costs are involved, raw material preparation is minimal, corrosion of piping is reduced, and insulation properties are better than those of other types of mineral wool (Dawson et al. 1987).

Snow and Ice Control. Durability, inertness (which prevents corrosion of automobiles), and dark color (which absorbs heat) have lead to extensive use of bottom ash and boiler slag to help control sliding on ice- and snow-covered roads. The ACAA reported that, in 1991, about 1.6 million tons of bottom ash and boiler slag was used for snow and ice control.

Reclamation. Coal combustion by-products can benefit severely disturbed areas (e.g., mines and disposal sites) by restoring site topography, preventing subsidence, and improving vegetative establishment and growth. Using coal combustion by-products in these situations reduces the need for borrowed topsoil.

3.4.1.2 FGD Scrubber Sludge Applications

Most scrubber sludges produced today come from wet scrubbers and have a solids content of 5-15% before dewatering; dewatering increases the solids content to up to 60%. (Newer wet scrubbers that produce sludges with moisture contents of less than 10% and dry scrubbers, which are less extensively used than wet scrubbers, produce waste materials that do not require dewatering.) To be used, thickened sludge is further strengthened via lime, cement, or alkaline fly-ash fixation. Scrubber sludges present greater challenges for reuse applications than coal combustion wastes because the sludges are not structurally stable or strong enough for construction and because they do not have the pozzolanic properties necessary for cement. Most FGD use and recovery operations require further reprocessing of the sludge or the use of dry scrubber sludge. In 1986, by-product utilization of FGD wastes accounted for only 1% of the total produced (EPA 1988). In 1991, just under 2% of the total FGD wastes were used. Applications of fixated wet FGD wastes and dry FGD wastes are summarized in the following paragraphs.

Road Construction. Fixated sludges can be used to produce a material for use as a subbase for road construction. In 1991, about one-third of FGD applications were for road base and subbase construction.

Wallboard. Waste materials from dry scrubbers, which include calcium sulfate (gypsum), have been used in wallboard manufacture. Waste materials from wet scrubbers can be oxidized to convert calcium sulfite to calcium sulfate. In 1991, about one-third of FGD applications were for wallboard manufacture.

Structural Fill. Wet sludges that have been fixated can be crushed to form aggregate for backfilling quarries, strip mines, and other areas. In addition, an aggregate of fixated FGD sludge can be used to produce concrete masonry blocks that have greater insulating, acoustic, and fire-resistance characteristics than blocks produced with conventional raw materials (Collins 1992).

Landfill Liners. Fixated sludge has a very low permeability (10^{-6} to 10^{-7} cm/s) because of its monolithic and cementitious properties. As such, fixated sludge has been used as liner material in Florida landfills, substituting for high-density polyethylene liners (Collins 1992).

Soil Amendments. Flue gas desulfurization scrubber sludges can potentially correct boron deficiencies, decrease subsurface soil acidity, and increase plant rooting depth and drought tolerance. Dry scrubber sludges (which can provide calcium, decrease subsurface soil acidity, and increase drought tolerance) are more suitable for agricultural applications than wet scrubber sludges (Korcak [undated]); however, few empirical data exist on the

agricultural use of FGD materials, and researchers expect that scrubber sludges will require more careful monitoring and application rates and that beneficial agricultural uses will be less than for other coal combustion materials. Research is underway to identify potential uses (Korcak [undated]).

Sulfur Recovery. Elemental sulfur can be recovered from some scrubber systems (e.g., dual alkali scrubber systems that produce sodium sulfate-sulfite sludges) through a process that produces hydrogen sulfide, from which elemental sulfur can be produced. The sulfur can then be used to manufacture fertilizers and sulfuric acid.

Artificial Reefs. Wet FGD sludge has been combined with fly ash to build artificial reefs. (See discussion of artificial reefs in Section 3.4.1.1.)

3.4.2 Considerations for CCT Waste Applications

Most coal combustion waste applications today use wastes from conventional coal-fired power plants. Applications for CCT wastes are being developed, but empirical data from such applications are limited. Researchers do not know how well conventional coal combustion waste applications will extrapolate to CCT wastes. For some applications, wastes from CCTs may perform better than wastes from conventional technologies; for others, CCT wastes may not perform as well. Benefits and concerns associated with CCT waste products are presented in the following list:

- *Fluidized-bed combustion wastes.* Typically not highly pozzolanic, FBC wastes are probably better suited for waste stabilization and agricultural amendments than for construction. Several factors contribute to the differences between conventional fly ash and FBC fly ash:
 - Lower FBC combustion temperatures prevent coal particles from fusing into glassy spheres and becoming pozzolanic (Collins 1992). Low combustion temperatures also produce larger amounts of incompletely burned carbon (Dawson et al. 1987).
 - The remaining carbon content of FBC ash, as measured by loss on ignition, is typically higher for FBC wastes than for conventional coal combustion wastes, leading to substandard concrete production.²⁸
 - In contrast to coal ash produced with conventional coal-fired plants, FBC wastes have higher calcium oxide (CaO; lime) and lower silicon

²⁸ Concrete produced with high carbon content (high loss on ignition) is weaker than concrete with low carbon content because carbon particles tend to absorb air-entraining agents, which are necessary to ensure a network of voids during the hardening process (Collins 1992).

dioxide (SiO_2) contents and therefore would not meet the minimum ASTM standard C618 for use as a mineral admixture in concrete (Dawson et al. 1987).

Because FBC wastes contain unreacted lime, they may be able to be used to directly stabilize certain types of waste; FBC wastes may also provide agricultural benefits. Research is underway in both of these areas.

Potential limitations for using FBC wastes are as follows:

- Fluidized-bed combustion wastes tend to harden when exposed to water. (This contributes to the stabilizing ability but means that dust suppression must be accomplished by covers, rather than by water spraying.)
- The fine particle sizes of FBC ash limit their potential for use in such applications as abrasives and removal of snow and ice (no great loss in Hawaii) without further processing.
- Fluidized-bed combustion materials may have a more limited use because the high alkalinity can cause crop damage if the Ph becomes too high. Also, the pozzolanic nature of the by-product can produce large chunks in the field (Korcak [undated]).
- Without additional processing, FBC wastes may not be suitable for artificial reefs. According to Dr. Frank Roethel (1993), one of the original coal-waste artificial reef investigators, unless the waste sulfur material can be separated from the rest of the FBC ash, gypsum will be created, which will cause the blocks to expand and structurally deteriorate.
- *Spray-dryer FGD wastes.* These wastes are similar to conventional fly ash, except that they (1) can be more reactive because of high concentrations of free lime and (2) are less appropriate for cement replacement because of high alkalinity and sulfites. Currently, the greatest potential use for these wastes is for road base or synthetic gravel (Collins 1992). Other candidate uses under investigation include stabilization material, asphalt mineral filler, cement, and brick manufacture.
- *Coal gasification wastes.* Wastes from slagging gasifiers are similar to the glassy bottom ash from conventional boilers and slagging-type combustors and have been used in road construction as base and subbase materials and as a fine aggregate in asphalt mixes. These wastes can also be converted to low-bulk-density ($15\text{-}55\text{ lb/ft}^3$) materials,

which can be used in lightweight precast products and structural concrete. Experiments are underway to make materials with even lower bulk densities (6-12 lb/ft³) for use as loose fill insulation and insulating concrete and in agricultural applications for soil and carriers for fertilizers (*Power* 1992). Wastes from nonslagging gasifiers (which operate below the fusion temperature of ash) are ash or partially bound agglomerates.

3.4.3 Considerations for Coal By-Product Use in Hawaii

Most of the previous discussion pertains to coal combustion by-product use in general; however, several factors will make beneficial use more appropriate in some situations than in others, and many of these factors should be considered when evaluating potential applications for the Hawaiian market. These factors include public perception, regulatory environment, market breadth and depth, economics, transportation, storage and handling costs, quantity and quality of by-product materials, need for further processing, environmental and health concerns, and potential liability. Each of these factors is discussed in this section.

3.4.3.1 Public Perception

Many reuse proponents argue that a major limitation to increased use of coal combustion by-products is the public perception that coal combustion by-products are inferior waste products, rather than beneficial raw materials. Many potential customers lack sufficient information or recall unsatisfactory experiences with earlier uses, when quality control was low and engineering standards did not exist. Contractors, engineers, and others are reluctant to use "new" materials in applications, especially large applications, without seeing that these materials perform as well or better than those with which they are familiar. Convincing potential customers of the benefits of using coal combustion by-products will be a significant challenge for utilities and ash marketers.

Potential consumers need to be educated on the variety of uses for combustion wastes. Dean Golden (1992) of the EPRI suggests holding seminars and workshops on ash utilization that show how much information has already been collected in these areas. Utilities and ash marketers must also communicate the benefits of coal ash utilization to legislators and regulators. Continuing research and demonstration to identify new uses for coal wastes and requiring compliance with various specifications for coal combustion by-products will help build exposure to and confidence in coal by-product use. These types of activities will be especially important in Hawaii, where the alternatives to beneficial use (i.e., disposal) are so expensive.

3.4.3.2 Regulatory Environment

Many states regulate coal combustion by-product use. In Hawaii, a solid waste permit for recycling has been issued to the existing AES plant, and a similar approach is expected to be taken for using wastes from other facilities to be built. This approach appears to be rational; however, in some situations, regulations have been implemented without specific knowledge of the constituents and their effects on human health or the environment (Horn 1988). In other states, reuse and disposal requirements are unclear. A recent 32-state survey of highway and environmental agencies indicated that few environmental agencies have drafted guidelines that address beneficial fly-ash use, and thus, such use is neither allowed nor disallowed, making approval for fly-ash use difficult to obtain (Golden 1992). With no established agency policy, a reviewer will likely require the potential user to obtain a waste management permit. The resulting costs, time, and restrictions may make the process uneconomic (Golden 1992). To avoid such situations in Hawaii, involved parties should stress that the state develop policies on the beneficial use of coal combustion by-products; for example, the Hawaii Department of Highways has no rules regarding coal combustion by-product use in road construction; however, the Hawaii Department of Health requires that any such applications be tested and approved prior to use. The state and county are currently reviewing the acceptability of "ash rock" (an aggregate manufactured from FBC by-products at the AES plant) as a subbase material. Until the City and County of Honolulu Department of Public Works and the Hawaii Department of Transportation grant approval for widespread state and municipal use, ash rock will be used only for private projects or where case-by-case approvals from these agencies are obtained (Sundstrom 1993). Regulators need additional exposure and education to draft rules authorizing the use of coal combustion by-products, thereby opening markets and encouraging development of additional applications.

3.4.3.3 Market

To avoid or reduce disposal, a coal-fired utility needs markets for existing and potential applications; for example, cement and concrete applications consume the greatest amounts of fly ash today, but markets in some regions may be approaching saturation as more utilities sell more by-products for this use. With the assumption that the wastes produced by the selected technologies are suitable for cement and concrete production — an assumption currently being examined by Hawaiian Cement Co., the only producer of portland cement on the island of Oahu — the extent of available markets in Hawaii will need to be examined in terms of proximity, compatibility with operations, and quantities needed. Preliminary investigations indicate that the market for coal combustion ash as a component of cement may be limited to about 10,000 tons/yr at current cement production rates (Guptill 1993). Whether production remains constant, grows, or declines depends largely on the construction market, which, in Hawaii, may be declining relative to the recent boom years. The markets for fly ash in concrete and as stabilization materials may be greater, but because low-cost substitute materials exist for these applications, the value of fly ash for concrete production is much lower than it is for cement production. The AES plant has

entered into a contract whereby Hawaiian Cement Co. will take all of the FBC fly ash and bottom ash produced by the Barbers Point facility for the next 10 years. Annual ash production at the Barbers Point plant is expected to range between 45,000 and 60,000 tons. Hawaiian Cement Co. indicated that it has various uses for the ash, including cement production (pending results of ongoing tests), aggregate in cement (pending public acceptance), and as a stabilizer for a high-moisture-content slurry resulting from washing clays and silts off rock used as aggregate. The company indicates that although it can use the 45,000-60,000 tons/yr, the ability to consume greater quantities is questionable. Another concrete and aggregate plant that is about the same size as Hawaiian Cement's Concrete and Aggregate Division could theoretically use an equal amount of ash, although this use is purely conjecture at this point and would require further investigation. Demand for fly-ash concrete and cement on the other islands depends in large part on the nature and amount of future development, although, in some cases, major resort developers have imported mobile cement and concrete materials and production units for use at those projects (Guptill 1993).

Gypsum presents a similar market concern. The current gypsum market in many regions of the country is at or near saturation, and adding more scrubber- or FBC-derived gypsum could further depress the market. The specific Hawaiian gypsum market should be evaluated before assuming that gypsum production is a viable reuse option.

The market for coal combustion by-product utilization as a soil amendment for agriculture in Hawaii should be thoroughly investigated. Sugarcane, which, in 1992, was grown on approximately 146,000 acres in the state and comprised over two-thirds of the total land used for agriculture (Hawaii Agricultural Statistics Service 1993), requires silica and lime amendments at the higher elevations, where the soil is more acidic. Tests indicate that an application rate of 2 tons/acre for a two-year crop, or an average of 1 ton/acre/yr, is the maximum amount of FBC ash that can be applied to sugarcane before damage to the crop will occur (Santo 1993);²⁹ however, because not all sugarcane requires soil amendments that can be provided by FBC material and because sugarcane production is decreasing throughout the state,³⁰ maximum application rates for FBC materials are estimated at about 40,000-60,000 tons/yr (Santo 1993). The second largest agricultural crop in Hawaii is pineapple (26,000 acres in 1992), but pineapples require an acid environment, and, therefore, no FBC soil amendments are necessary. Macadamia nuts, coffee, and guava (combined growing area of 30,000 acres in 1992) all require some level of liming, and an additional FBC market may exist for these crops, although the application rates are not known. The AES plant has sold about 2,000 tons of FBC by-products to a sugar plantation in Oahu, where material and transportation costs are low (FBC source and use areas are on the same island)

²⁹ Other coal combustion products may damage plants at higher (or lower) application rates, but tests on these other materials would need to be conducted.

³⁰ Since 1988, Hawaiian sugarcane acreage has declined by about 5%/yr. Not only is sugarcane production declining, but overall agricultural acreage in Hawaii is declining. In 1988, the state had 255,800 acres in crop production; in 1992, this number had decreased by 17% to 212,200 acres (Hawaii Agricultural Statistics Service 1993) because of high agricultural labor costs and the demand for more land for real estate development (Santo 1993).

and where more costly substitute materials (i.e., crushed coral) would have to be imported from Kauai or the Big Island.

For some applications, the markets may not be saturated, but the use may not be appropriate in Hawaii; for example, 200,000 tons of coal combustion wastes were used for grouting in 1991; however, the bulk of this grout was used to anchor and plug oil and gas wells. Similarly, one of the top five uses (in terms of quantities consumed) of coal combustion by-products in 1991 throughout the United States was for snow and ice control, but the Hawaiian market demand would be minimal for this application.

In general, specific beneficial use markets need to be matched with need, or a previously unmet need must be identified. Additional research in terms of specific by-products (each product, especially each CCT by-product, has its own set of chemical and physical characteristics) for specific applications needs to be undertaken before definitive market conclusions can be drawn. The previous paragraphs merely present the kinds of issues that must be addressed; actual experience with CCT by-products in Hawaii (and also on the mainland) is limited.

3.4.3.4 Economic Competitiveness

The value of coal combustion by-products comes in part from eliminating the costs of extracting natural materials from the earth. Another potentially significant cost factor for Hawaiian use of materials is transportation. To the extent that coal combustion by-products can substitute for materials that would otherwise be imported, economic benefits result; but if competitive materials exist on the islands, shipping coal combustion wastes may cost more than using the existing materials; for example, using readily available coal combustion by-products to substitute for natural aggregates in concrete production and road base and subbase construction may be cheaper than using natural materials such as "blue rock," which must be mined from the mountains, or sand and coral, which must be mined from flat areas that may be more appropriate for residential and urban uses, and hence are more costly. Similarly, some CCT wastes, especially FBC wastes, can substitute for crushed coral as a soil amendment as long as the costs for the substitute materials are significantly lower than those for crushed coral. This cost factor is because crushed coral provides more lime without the potential for heavy metal contamination that can occur with some coal combustion wastes. Therefore, if the cost for FBC material begins to approach that for crushed coral, the crushed coral will be used, and the market for FBC material as a soil amendment will diminish (Santo 1993). More detailed study would be necessary to estimate the costs and benefits of using coal combustion by-products to substitute for natural materials in different applications.

The primary value derived from using coal combustion wastes is the reduced or avoided costs of disposal, rather than additional cash flow. Nonetheless, with landfill costs in Hawaii ranging from about \$25/ton at a C&D landfill (assuming the ash met the requirements that would allow it to be disposed of in such a facility) to \$54/ton in an RCRA-approved MSW landfill (excluding transportation), avoiding these costs for large

quantities would represent a significant savings to the utility. Examples of economic issues associated with specific applications are presented in the following paragraphs:

- *Cement and concrete.* The EPRI recently evaluated the economics of fly ash in cement and concrete production (Dawson et al. 1987). The following discussion is based on that evaluation. At the national level, the fly-ash application commanding the highest price is as a substitute for portland cement in concrete production. (The revenues derived from fly ash as a raw material in concrete production are limited because the materials against which the fly ash competes — limestone, clay, shale, and sand — are inexpensive.³¹) However, a significant difference exists between the price of portland cement and that of substitute fly ash: in 1987, concrete users paid about \$52/ton for portland cement and about \$10-\$15/ton for fly ash (excluding transportation). Ash marketers today sell fly ash as a substitute for portland cement for about \$15/ton (excluding transportation) (McCormick 1993). Thus, even using the cement/concrete application with the highest value, utility owners and operators could expect to receive no more than about \$15/ton. This estimate could go down if transportation costs are high, if the fly ash does not meet minimum ASTM performance standards, or if an ash marketer (who needs a fee for his service) is used.
- *Fill material.* According to David Sundstrom (1993), AES area superintendent, about 20,000 tons of FBC by-products from the Barbers Point AFBC plant was sold as a manufactured aggregate called "ash rock" to local contractors for use as a subbase aggregate at prices up to \$6/ton.³² (Fill dirt in Hawaii commands about \$6.30/ton.) Sundstrom estimates the potential market for ash rock as a subbase aggregate at 250,000-350,000 tons/yr in the immediate geographic area of the AES plant, but success in penetrating this market will depend on documentation of the engineering properties of ash rock and the granting of state and local regulatory approvals (Sundstrom 1993).
- *Metals extraction.* In general, metals extraction from fly ash is not economically competitive with other methods; however, a significant cost component of metals production from ores is the crushing of ores to fine particle sizes. Using fly ash eliminates this step. Such savings, combined with availability, location, and other externalities, may make fly ash more competitive as a source for metals extraction. To more

³¹ Depending on the availability of these materials in Hawaii, the revenues derived from substituting fly ash in concrete manufacture may be higher than those at the national level.

³² Ash rock is a manufactured product consisting of fly ash, bottom ash, and water, which have been combined and allowed to cure or harden. The product is then broken up into well-graded aggregate for use as fill.

accurately assess the economic viability of this option, factors such as the metals content of the fly ash, fly-ash extraction technologies, coal combustion processes used, the coal to be burned, and the markets for metals in Hawaii need to be analyzed.

- *Coal-waste artificial reefs.* While research has demonstrated the structural feasibility for coal-waste artificial reefs, no domestic study has shown such reefs to be economically viable; however, as land costs rise or as fishing or seaweed markets create more demand and as waste disposal costs rise, evaluating such uses in Hawaii may be appropriate.

More detailed economic evaluations should be undertaken for these and other potential coal combustion waste applications in Hawaii, such as waste stabilization, abrasives use, mineral wool production, and land reclamation, to determine more precisely the economic competitiveness of the particular by-products generated from the coal-burning technologies to be used in Hawaii. A rough estimate of average current receipts from beneficial use of FBC by-products in Hawaii comes from recent history at the AES plant. Of the roughly 44,000 tons of ash produced at the AES plant for the year of September 1, 1992 through August 31, 1993, about 22,500 tons has been sold for various applications. Total receipts for these sales were about \$52,000, for an average per-ton price of about \$2.30 (Sundstrom 1993). Future receipts will depend on the results of various tests, competitive materials, public acceptance, and other factors discussed in this section.

3.4.3.5 Transportation, Storage, and Handling Costs

The high bulk and low value of coal combustion wastes may make transportation, storage, and handling costs significant factors in determining the economic feasibility of coal combustion by-product utilization. In general, the closer the application is to the utility, the more favorable the economics will be. Any assessment of coal combustion waste use in Hawaii needs to include estimates for these factors; for example, while coal combustion wastes may be useful for snow and ice control, the areas potentially needing such materials (e.g., Haleakala National Park on Maui and Mauna Kea on the Big Island) may be far enough from the utility that transportation and handling costs may limit their use.

3.4.3.6 Quality and Quantity of Combustion Wastes

Certain applications, such as cement production or soil amendments, may require a constant or at least a predictable supply of ash. Ash producers and ash consumers will need to address potential ash supply issues; but of greater potential concern is ash quality and consistency. Once ash constituents and qualities are identified and matched with uses, customers need assurance that the ash that they get has the consistency and quality that they need for their specific applications. Soil amendment applications in Hawaii must be thoroughly tested, and research is underway for using coal combustion by-products in the sugar fields, but results are not conclusive. Variations in coal by-product quality can result

from variations in coal quality or from frequent cycling or other upsets. To minimize ash quality problems, some facilities use additional controls, such as monitoring devices for carbon content³³ and detectors for particle size. In addition, ash processing facilities can be installed to convert high-carbon fly ash into a salable form (e.g. for lightweight aggregate for use in concrete masonry). Depending on the nature and extent of potential Hawaiian markets, utility owners and operators may need to evaluate the costs and benefits of installing additional quality assurance controls.

The quality of scrubber sludge produced in Hawaii may enable a broader range of uses than scrubber sludge produced elsewhere because of the unwritten requirement that coal burned in Hawaii must have a sulfur content no greater than 0.5%. This requirement implies that dry, rather than wet, scrubbers may be sufficient. High-efficiency (about 90%) wet scrubbers are typically used with high-sulfur coal; dry scrubbers (about 70% efficient) may be adequate for low-sulfur coals. Dry scrubbers produce a dry product, which is more easily used than wet sludges.

3.4.3.7 Need for Further Processing

Many applications, especially some of those currently in research and development, will require additional treatment of coal combustion wastes. Such treatment can range from sifting to ensure that only particles of a certain size are included to solidifying and then crushing the solidified material into aggregate sizes suitable for fill or other applications, as the AES plant has done for preparing ash rock. The extent of processing depends on the ultimate application, as well as on the coal type and generation process; for example, scrubber sludges will require dewatering if they come from a wet scrubber system but may be used more directly if generated by a dry system. On the other hand, boiler slag, with its attractive dark glassy appearance, angularity, and range of particle sizes, may be used in many applications with very little, if any, further processing.

3.4.3.8 Environmental and Health Concerns

The primary environmental concerns associated with using combustion by-products are the same as those with disposal: the potential for ground and surface water contamination. Unknowns are also associated with using combustion by-products in agriculture; for example, some metals may bioaccumulate to toxic levels in plants, potentially endangering animals or humans consuming those plants. Additional research that considers Hawaiian soil and geologic and hydrogeologic conditions will help address these issues.

³³ Ash with a carbon content that is too high tends to absorb the air that is needed in the concrete for workability and resistance to freezing and thawing.

3.4.3.9 Potential Liability

As with any new material, consumers may have concerns about performance of a new product. If, for some reason, an application that used combustion by-products should fail, the supplier of that material could become liable. This concern may be more perceived than real, especially with threats of Superfund liability. As coal combustion waste applications increase — both via demonstrations and commercial use — performance histories will be developed that should address these fears. Hawaiian utility owners and operators should keep informed not only of Hawaiian application history, but also of developments and successes of applications — especially of CCT wastes — in other areas that could be applied to Hawaii.

3.4.3.10 Summary Considerations for By-Product Use in Hawaii

An evaluation of potential applications for by-products should consider several factors. First, the quantities of wastes and the constituents of those wastes must be estimated. Knowing the constituents is important for identifying regulatory issues, and knowing both the constituents and the quantities is necessary for market analysis. It is quite possible that all of the coal combustion wastes from the existing 180-MW AES AFBC plant will be used; however, at this point, how much additional waste can be absorbed is not clear. Absorption amounts will depend on the simultaneous combination of a number of factors; for example, the demand for ash as a portland cement manufacturing component may be high if construction continues to grow in the state. The extent to which ash can be used to meet this demand will depend on the results of tests that are currently underway to determine if the Barbers Point ash meets ASTM specifications for cement, as well as the public acceptability of concrete and fly ash that contains coal combustion by-products. More research and education are needed to assess market breadth and depth. An important part of this research will be to characterize in detail the constituents of the wastes expected from the specific candidate coal combustion technologies and to match these characteristics with specific uses. The research will also need to evaluate whether adding monitoring or other equipment will be required to maintain by-product quality. In some cases, prospective users may need to test samples of waste products to determine how well they can substitute for other materials. Environmental testing will also be required. Because of the unknowns regarding the potential use of coal combustion by-products in Hawaii, and because of the relatively small geographic area over which these applications can be used, carefully evaluating a number of potential applications will be important to maximize the beneficial use of these by-products.

4 SITING AND INFRASTRUCTURE ISSUES

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4.1 OVERVIEW

Efforts undertaken to increase the amount of coal-fired generating capacity in Hawaii will necessitate the determination of where to locate such new generating capacity. As indicated by the extensive amount of analysis that has been conducted in support of the Hawaiian Electric Company's (HECO's) efforts to site a new coal-fired generating facility, such a determination involves a number of different considerations. Variables that must be factored into the decision-making process include the physical requirements of such facilities, methods that could be used to transport coal to the facility (and waste material away from the facility), the public's perceptions of the relative costs and benefits of and subsequent desirability of the proposed facility, and the implications of various legal and regulatory restrictions, such as rules governing air emissions and water quality. To a large extent, many of these factors are interrelated.

The focus of this section is the major factors that must be addressed in the siting process. These factors are divided into four main categories: facility requirements, transportation-related issues, public perceptions, and legal and regulatory barriers and constraints. The discussion of facility requirements addresses such issues as the resource requirements (e.g., land and water) of different coal-based technologies. Transportation-related issues include the types of transport that could be used to bring coal to the generating facility and take waste material away and the potential impacts of each transportation mode on the affected environment.

The question of public perceptions is especially important in light of the results of the survey conducted by the state of Hawaii's Department of Business, Economic Development & Tourism (DBEDT) as part of the Hawaii Energy Strategy Workshop that was held in late 1992 (DBEDT 1992). Based on comments received at the workshop, coal may experience public opposition as an option for meeting Hawaii's energy needs in the future. As such, efforts to site additional coal-fired generating facilities may experience difficulty. It is therefore important to be aware of the experiences of other entities that have attempted to site such facilities. Equally important is an understanding of the various approaches that can be employed in attempts to win the public's approval of this type of facility.

Finally, legal barriers and constraints must be considered in the siting process. Regulations regarding air and water quality are especially important in this regard. Depending on the existing air quality at a proposed site, it may be more or less difficult to construct a new facility that will result in additional emissions of air pollutants such as sulfur dioxide (SO₂), nitrogen oxides, and particulate matter. In a similar manner, restrictions on water use and effluents may render certain land uses impractical on the basis of cost.

Much of the following discussion addresses issues that involve both qualitative and quantitative dimensions; for example, in the case of resource requirements, land uses can be measured in terms of the amount of land required to support the proposed facility. In addition, the proposed land use may affect the quality of adjacent land uses. Theoretically, this impact could be measured in dollars as well. The extent to which such values have been reported here is constrained by the availability of data in the open literature. Consequently, although much of the discussion that follows focuses attention on the potential costs attributable to coal-fired generating facilities, there are insufficient data in many cases to estimate the magnitude of such costs; however, it is important to recognize the potential for such costs in a qualitative manner so as to better inform the decision-making process.

The consulting firm of Black & Veatch, Inc., has undertaken an extensive analysis of potential sites for a new coal-fired generating facility on the islands of Oahu, Lanai, and Molokai (Black & Veatch, Inc. 1992b). The discussion that follows is intended to raise important additional questions, especially those related to public perceptions of and reactions to the siting of coal-fired plants and supporting transportation systems.

4.2 FACILITY REQUIREMENTS

This section examines the resource requirements of the different coal-fired technologies that might be employed in Hawaii. These requirements are considered in the context of the impacts they could have on the surrounding environment. In addition to the requirements of the facilities themselves, it is important to recognize that, depending on the location of the facility, construction of new transmission lines might be required to deliver the power from the generating facility to end-users. The process of siting and constructing transmission lines has become an increasingly difficult issue in recent years. This difficulty reflects, in large part, the public's growing concern over the questions of whether and to what extent electromagnetic fields (EMFs) associated with high-voltage transmission lines pose health risks (North American Electric Reliability Council 1990).

The primary purpose of this discussion is to identify facility-specific characteristics and physical requirements that could influence the public's attitudes toward the siting of such facilities. Attention is focused on, among other things, the costs associated with the siting of coal-fired generating units. In addition, facility requirements that could complicate the siting process are noted.

4.2.1 Resource Requirements of Coal Technologies

The amounts of natural resources — primarily land and water — required to support a particular generation technology based on coal depend on the specific characteristics of the technology, including unit efficiency, capacity, and the amount of load to be served by the unit. The single most important determinant of the amount of land required is whether the combustion wastes — ash and possibly pollution control wastes — are managed on-site or off-site. Variations in land requirements are also influenced by the number of generating

units at the plant site and the amount of coal reserves that must be maintained on a continuing basis to meet reliability requirements. According to a report prepared by Black & Veatch, Inc. (1992a), land requirements of a coal-fired electric generating plant can range from 10 to 500 acres, depending upon the type and size (measured in terms of generating capacity) of the facility in question; for example, a 180-MW pulverized coal (PC) unit could be built on as little as 10 acres, assuming off-site waste management (Black & Veatch, Inc. 1992a). If waste is instead managed on-site, as much as 500 acres would be required. Acreage requirements are similar for atmospheric fluidized-bed combustion (AFBC) units, pressurized fluidized-bed combustion (PFBC) units, and gasification combined-cycle (GCC) units (Black & Veatch, Inc. 1992a).

The question of transmission line requirements is not unique to coal-fired technologies; the siting of any type of generating facility could entail the construction of new transmission capacity. Nonetheless, the issue needs to be addressed because it could complicate the siting approval process. As is discussed in Section 4.4, proposals to site new transmission lines and coal-fired generating facilities have frequently been met by strong opposition from the public. Consequently, attempts to site both types of facilities simultaneously could significantly increase such opposition. If new transmission capacity is required to connect a new generating facility to the existing grid, this capacity will entail additional land-use requirements. According to Bertram (1983), high-voltage transmission lines require 12-15 acres/mi. The total amount of land required to construct the additional transmission capacity will depend on the distance to be covered by the new transmission lines and the width of the right-of-way (or easement). One suggested approach to addressing the concerns noted earlier over the potential health effects associated with EMF is to widen rights-of-way to minimize exposure to EMF. This approach would obviously increase land requirements.

Water requirements for the various coal-fired technologies also vary somewhat by technology; for example, a 180-MW PC plant is estimated to require approximately 14.1 million gallons of raw (untreated) water per day (mgd), of which 13.1 mgd is for cooling purposes (Black & Veatch, Inc. 1992a). A 180-MW AFBC unit is estimated to have similar water requirements (Black & Veatch, Inc. 1992a). In contrast, a 232-MW GCC unit is estimated to consume 13.5 mgd of raw water, with 11.3 mgd being used for the cooling tower makeup (Black & Veatch, Inc. 1992a). While the raw water can be saline, a percentage ranging from 7% to 17% must be treated for use as potable and service water (Black & Veatch, Inc. 1992a).

Transportation of coal to the generating facility and of wastes away from the site also entails resource requirements. Because coal must be delivered to Hawaii by ship, existing ports must be used to unload the coal, or new ports must be developed. Depending upon how intensively the port services are currently employed, this usage could result in the displacement of some current uses. At a minimum, it is likely that waiting times for berthing and subsequent unloading will increase (Mahr 1991). In those cases where a port with the required characteristics (e.g., sufficient depth for deep-draft ships and space to accommodate steorage requirements) does not currently exist, such a facility would have to be constructed.

The construction of new port facilities will displace any current uses of the affected resources.¹ Off-shore unloading of coal could also be used to move the coal to a land-based staging area. Szpunar et al. (1989) describe the use of a ship unloader mounted on a barge to move coal between a barge and a ship on the lower Mississippi River. This approach could be used to deliver coal to islands with less developed port facilities.

Unless the proposed generating facility is located adjacent to the port where the coal is unloaded, the coal must then be transported to the facility. Land-based transport options include the use of trucks, conveyors, and coal-slurry pipelines. A conveyor system is being used to transport coal to the 180-MW coal-fired plant operated by AES Corp. Each of the options will entail either the use of existing resources, as in the case of truck transport over existing roads, or the conversion of resources from existing uses. An example of the latter would be the construction of a pipeline or conveyor in a previously undeveloped area. Transport requirements may render certain candidate sites less attractive or infeasible and are likely to have important consequences for the public's reaction to a proposed site. The various transport modes are discussed in detail in Section 4.3.

4.2.2 Impacts on the Surrounding Environment

Depending on the specific location, the siting of a coal-fired plant will result in a variety of impacts on the surrounding environment; for example, visibility will be affected to the extent that physical structures, such as the generating units, cooling towers, and transmission lines, interfere with previously unobstructed views. In addition, air emissions attributable to the facility operations and to coal transport may degrade visibility in the surrounding area. Depending on the uses of the site prior to construction of the proposed facility, recreational activities and tourism may also be affected. Some amount of community disruption is also likely to occur. To the extent that these types of adverse impacts occur, the total costs attributable to the proposed facility would increase, as discussed in Section 4.2.3.

Air emissions from coal-fired generating facilities have also been linked to a range of adverse impacts, including health effects, damage to ecosystems, and materials damage attributable to acidic deposition. As is discussed in Section 4.5, air emissions may also result in water pollution and corresponding adverse effects on health and environmental quality. The adverse cost effects of certain air emissions — SO₂, nitrogen oxide, carbon dioxide, carbon monoxide, particulate matter (total suspended particulates; TSP), volatile organic compounds, and methane — are addressed in Section 5, which summarizes currently available data on the costs of coal-fired generating facilities, including estimates of the costs attributable to those air emissions. The remainder of this section addresses impacts other than those directly related to pollution that might result from siting a coal-fired generating facility in a particular location. While data that would be used to quantify these impacts on

¹ It is important to recognize, however, that construction of a new port would also result in additional external benefits insofar as it could be used to facilitate the import and export of other goods and services.

a dollar basis are currently unavailable, it is nonetheless important to be cognizant of these potential impacts in the course of evaluating alternative candidate sites.

4.2.2.1 Visibility

Construction of a coal-fired generating facility will have some degree of air quality impact. The ease with which a plant will be permitted will depend on the applicant's ability to satisfy concerns about, among other things, adverse impacts on air quality. Visibility degradation is one of the most identifiable forms of air pollution; as a result, it has caused significant concerns in particularly scenic areas and has the potential to impede the permitting of a facility in Hawaii. Visibility degradation occurs as either a visible plume from a single source, regional haze from a number of sources, or the presence of a large facility that is itself obstructive. A number of activities can cause or contribute to visibility degradation, including plant construction, operating and maintenance (O&M), the transport of coal to and waste away from the plant, and, in some cases, the construction of the fuel transport system. Impacts from construction notwithstanding, the fuel transport medium that causes the greatest visibility degradation is trucks, particularly when road surfaces are not fully paved.

4.2.2.2 Recreation

Recreational activities, such as hiking, biking, swimming, boating, and picnicking could be adversely affected by the siting of a coal-fired generating facility; for example, the land-use requirements of such a facility could displace certain activities. In addition, the physical presence of such facilities close to where such activities occur could diminish the quality of the recreational experience by intruding on the natural environment. In addition to the facility itself, transmission lines from the facility could affect recreational activities by discouraging activities in the corridor through which the transmission lines pass.

Depending on where the facility is located, transport of the coal could also affect recreational activities; for example, if a new port needs to be constructed, water-related recreational activities are likely to be displaced. In addition, if the coal must then be transported over land to the facility (as would be the case when the facility is located some distance from the port), other recreational activities (e.g., hiking and biking) could also be adversely affected. This would be most likely to occur in those cases in which construction of roads or of a conveyor system is required. If truck transport is used to deliver coal to the generating facility over existing roads, impacts would result from the adverse effects that exhaust fumes and noise from the truck traffic have on the surrounding environment, as well as the increased traffic.

4.2.2.3 Community Disruption

Depending upon the specific location of a coal-fired facility, community disruption will be more or less severe; for example, consider the situation in which an oil-fired generating unit located in an industrial area is retrofitted to burn coal. Assume also that the fuel oil was delivered via pipeline but that the coal will be delivered to the facility by truck. The increase in truck traffic will increase congestion on certain roads, extending travel times during certain parts of the day. The actual amount of truck traffic will depend on the size of the generating unit, its load factor, and the amount of coal per truckload. Concomitant increases in noise and air pollution will result in additional adverse impacts on the environment.

In the situation in which a facility is located in an area where no similar type of facility existed previously, the disruption is more obvious. Construction of the facility and the supporting infrastructure (e.g., new roads or a conveyor system to deliver coal to the facility) will result in increased noise and traffic. Assuming the facility results in new jobs and an influx of people into the area, this will impose additional burdens on the existing infrastructure. In addition, there will be an increase in demands for publicly provided services ranging from police and fire protection to water usage. The magnitude of these impacts will depend, to a large extent, on the proportionate increase in population attributable to the new facility. Increased demands for housing might also result in increased land use requirements, depending on prevailing vacancy rates.

4.2.3 Costs

Economists categorize costs according to whether they are private (or internal) or external. Private costs consist of out-of-pocket expenses, such as expenditures on capital equipment and labor. External costs are costs borne by a third party that is not involved in the transaction that gave rise to the costs in question. One of the most common examples of an external cost is the adverse effects of environmental pollution that results from a production process. To the extent that the incidence of these effects is on individuals who are not involved in the production or consumption of the good in question, external costs exist.

External costs need to be considered in the decision-making process in order to better ensure that resources are allocated in an efficient manner. A necessary, although not sufficient, condition for economic efficiency is that the benefits of the proposed action exceed the costs incurred. With respect to the siting of coal-fired generators, a decision is being made to allocate land (and other resources) to a specific use. The decisions regarding land use involve an opportunity cost (i.e., the next best use of the land) that must be factored into the decision-making process; however, depending on where the facility is located, adverse impacts may be imposed on third parties as well — individuals may incur external costs. Thus, it is important to recognize not only the out-of-pocket expenses (or what are sometimes referred to as internal or private costs) that will be incurred in the construction and operation of such a facility but also the external costs associated with such facilities. The sum of the internal and external costs represents total social costs and constitutes the appropriate

measure of total costs of the proposed action. These total social costs must then be weighed against the total social benefits of the proposed project.²

4.2.3.1 Construction and Operation and Maintenance

Construction costs and O&M costs for each of the types of facilities considered in this report are presented in Section 2, which describes the various candidate coal-fired technologies, and in Section 5, which summarizes the data that have been incorporated into the integrated resource planning (IRP) spreadsheet model.

4.2.3.2 External Costs

Coal-fired generating facilities have the potential to generate a variety of external costs. Certain sources of such costs, in particular air emissions, are discussed in Section 4.5; estimates of the dollar value of such costs for selected types of emissions have been incorporated into the IRP spreadsheet model described in Section 5. In addition to air emissions, coal-fired facilities contribute to noise pollution. Day-to-day operations at the site add to the levels of background noise and can impose costs on nearby residents. Depending on how coal and wastes are transported to and from the facility, additional noise may result. (Transportation-related external costs are discussed in more detail in Section 4.3.3.2.)

Additional external costs include the various types of impacts discussed earlier (i.e., adverse effects on visibility and on recreation and community disruption). Specific sources of these external costs include the following:

- **Visibility Impacts**
 - Loss or decrease in the quality of scenic vistas
- **Recreation**
 - Displacement of current activities
 - Reduction in the quality of nearby activities
- **Community Disruption**
 - Decline in property values
 - Increased burden on publicly provided services and infrastructure.

² Total social benefits are equal to the sum of private benefits and external benefits. External benefits are defined in a manner similar to the definition of external costs.

As a technical matter, the costs attributable to increased noise levels, decreased visibility, and loss of recreational opportunities (or a decrease in the quality of recreation) would be measured as the amount of money affected individuals would be willing to pay to avoid these adverse impacts.³ The amount individuals are willing to pay would, in turn, be determined by factors including, among others, the income of the affected individuals; their preferences regarding noise levels, visibility, and recreation; and the change in these variables attributable to the facility and its day-to-day operations. It was noted previously that there are no data that could be used to construct a meaningful estimate of such costs. Estimates would require information on the specific location of the proposed facility, current land-use patterns, and the characteristics of the affected population. Nonetheless, it is important to consider, at least qualitatively, the potential effects of such costs in the decision-making process.

Any increase in land use for additional housing would not be considered an external cost, since the opportunity cost of diverting the land from alternative uses presumably would be reflected in the selling price. It is also important to recognize that the siting of a new facility could increase the value of certain activities, such as commercial business activities in the affected area; for example, any increase in population would result in increased demand for food, clothing, etc. and thus would benefit local merchants. In this case, the external costs would be negative (i.e., the facility would give rise to external benefits).

The costs and benefits borne by the local economy could be estimated on the basis of the expected increase in the demand for goods and services; for example, the costs of an increase in demand for publicly provided services could be estimated on the basis of the costs per capita incurred to provide such services and the expected increase in population. The potential benefits (e.g., increased income, output, and employment in the local economy) of the proposed facility could be estimated with the use of a regional input-output model. Such models can be used to estimate both the direct effects of spending in the local economy, as well as the indirect effects that result from an increase in demand for goods and services. Increased costs with respect to infrastructure would be more difficult to estimate but should be considered at least qualitatively.

At a minimum, it is important to inventory the different external costs and benefits that could result from siting a coal-fired generating facility in a particular location. Weights could be assigned to the various impacts, which could, in turn, be measured on a likert-type scale. This process, which is similar to the approach used by Black & Veatch, Inc., in the evaluation of candidate sites for HECO, could be used to produce a relative ranking of alternative candidate sites.

³ In fact, it could be argued that the cost would be measured as the amount of compensation individuals would require to offset the adverse effects of the increased noise levels; however, the debate over the appropriateness of willingness to pay versus willingness to accept compensation as a measure of damages is beyond the scope of the present discussion.

4.2.4 Impact Mitigation Recommendations

The quality of the natural surroundings in Hawaii is valued highly by residents, is a magnet for tourism (the state's largest industry), and is protected from degradation by stringent state laws; for these reasons, a high level of concern about adverse environmental impacts from a new generating facility can be expected. Various actions could be undertaken to mitigate the types of external costs described previously.⁴ Such efforts could range from modification of the proposed facility to the construction of walls along roadways to contain noise. Specific options include the following:

- Burial of transmission lines,
- Add-on controls to minimize air emissions that affect visibility,
- Development of new recreation areas or facilities, and
- Compensation to the local community to help defray the costs of increased demand for publicly provided services and infrastructure requirements.

4.3 TRANSPORTATION-RELATED ISSUES

The decision of where to site new coal-fired generating facilities will be influenced, in part, by the ability to transport coal to the facility. The first issue that arises in this regard relates to port facilities. While ports with depths of 35 ft or more currently exist on all but one of the islands, efforts to site coal-fired generating facilities will necessitate the development of some means to unload coal from transport ships onto those islands. The technologies that are used in ocean shipping and in loading and unloading of coal from ships have developed considerably in recent years; for example, coal can be unloaded from deep-draft ships onto smaller barges, which could then be used to transport the coal to various islands. Barges have the advantage of requiring less depth than deep-draft ships at the port facility. A fully loaded barge carrying 15 tons of coal has a draft (or depth) of approximately 9 ft (Szpunar et al. 1989). In contrast, a fully loaded ship can draft as much as 65 ft or more (Mahr 1991; Szpunar et al. 1989). Development of port facilities to handle barge delivery of coal would be less than the costs of facilities designed to handle deep-draft ships.

Loading and unloading facilities would require construction at the origin and terminus of the overland coal transport routes. The unloading of coal from the ship to the truck, conveyor, or pipeline would occur at the port and would likely require purchase or

⁴ In order to determine the economically efficient amount of mitigation efforts, it would be necessary to be able to estimate the external costs described previously. The reduction in these external costs attributable to the mitigation efforts represents the benefits of mitigation. For economic efficiency, mitigation should continue up to the point at which the marginal costs and benefits are equal.

construction of unloading equipment. (Truck transport could rely largely on the existing port infrastructure [e.g., roads]). Facilities for unloading coal at the transport terminus would also be required because no preexisting facilities would be present to support such activities.

4.3.1 Transport Mode Selection

Once the coal is unloaded from the ship, the coal then must be delivered to the generating plant. In situations in which the generating facility is located close to the port facility, this delivery will be a relatively straightforward matter; however, as the distance between the two facilities increases, transportation of the coal will become a more important issue. Various modes are available for transporting coal over land, including trucks, conveyor systems, and coal-slurry pipelines. Each of these modes offers advantages and disadvantages. These trade-offs must be weighed in the decision of where to site coal-fired generating facilities. (Rail transport is also used to move coal; however, this transport mode is only cost-effective over relatively long distances [30 mi or more] and when the volumes transported are relatively large [Szpunar et al. 1989]. Therefore, rail transport is not considered here.) Various characteristics of each of the three transport modes considered subsequently are summarized in Table 4.1.

4.3.1.1 Trucks

Trucks offer one of the more obvious means of transporting coal over varying distances. In fact, truck transport captured an increased share of the contract coal market in the United States between 1979 and 1987 (Energy Information Administration [EIA] 1991). Truck transport of coal offers a number of advantages, including easy access to sources of coal and power plants, a high degree of flexibility, and the ability to respond quickly to customers' needs (EIA 1991); however, truck transportation also involves a number of disadvantages, including the fact that it is labor- and fuel-intensive and entails high capital replacement and maintenance costs and high administrative costs (EIA 1991). In addition, truck transport can result in a number of adverse environmental impacts, including diesel exhaust emissions, dust (from the coal being transported and the road surfaces), noise, erosion, wildlife habitat disruption, property damage, and road surface deterioration (Webber et al. 1987).

In general, truck transport is preferred to alternative transport modes, such as rail and coal-slurry pipelines, for shorter distances (i.e., 70 mi or less) (Szpunar et al. 1989). In addition, assuming roads connecting the source of the coal (e.g., a port facility) and the destination point (the generating facility) are already in place, transport is readily available. This contrasts with pipelines and conveyors. For each of these transport modes, the required infrastructure would have to be constructed before transportation of coal could commence. Depending upon the permits, etc., that would be required before these alternatives could be constructed, this advantage would be more or less important.

TABLE 4.1 Summary of Overland Coal Transport Mode Characteristics

Variable	Transport Mode		
	Trucks	Conveyor Systems	Coal-Slurry Pipelines
Optimal range (mi)	<70 ^a	<15 ^a	>100 ^a
Optimal volumes	25 tons/truck	2-10 million tons/yr ^a	>5 million tons/yr ^a
Resource requirements			
Land (acres/mi)	10-12 ^b	NA ^c	9-12 ^d
Water usage (gal/ton)	0	0	225 ^c
Transport costs	\$5.99/ton ^{e,f}	\$1.28-\$4.62/ton-mi ^g	\$26.46/ton ^{a,h}
Major advantages	Flexibility; easy access to pickup and delivery points	Greater range of surface grades than trucks or pipelines	High-speed transport; minimal environmental impacts (after construction is complete)
Major disadvantages	Noise; dust; air pollution; property damage; road surface deterioration	Noise; visibility impacts; dust	Reliance on a large quantity of water (for water-based slurries); water treatment requirements; geographic limitations (grades and turns)

^a Source: Szpunar et al. (1989).

^b Source: Webber et al. (1987).

^c NA, not available.

^d Source: Bertram (1983).

^e Source: EIA (1991).

^f Note that this figure does not include the costs of road construction or maintenance.

^g Source: Tavares (1984); estimates based on 500,000 tons/yr.

^h See accompanying text for derivation of this figure.

4.3.1.2 Conveyors

Conveyor systems are used to transport coal between locations ranging from points within a mining facility to mines and other transport modes or end-use facilities (e.g., a coal-fired generating facility). In contrast to coal-slurry pipelines, which are generally used over long distances, conveyors are more applicable to relatively short distances of 15 mi or less (Szpunar et al. 1989).⁵ Because of this difference, conveyors are more competitive with trucks as a means of coal transport than are slurry pipelines. In addition, conveyors have an advantage over trucks in their ability to scale slopes and make tighter turns; conveyors can be used on grades of 30% to 35%, while trucks are confined to surfaces of 5% to 8% (Szpunar et al. 1989). Conveyors also have an advantage over trucks in that they deliver coal on a continuous basis, as opposed to an intermittent basis. Szpunar et al. (1989) cite the following as important determinants of the cost-effectiveness of coal conveyors relative to truck hauling:

- Presence or absence of roads, available truck facilities, etc., in the existing infrastructure;
- Site characteristics (grade constraints, weather characteristics, etc.); and
- Amount of coal to be moved.

Adverse impacts attributable to conveyors include noise, visibility impacts, and conversion of existing land uses. In addition, fugitive dust is often produced by conveyors, particularly if they are uncovered. This dust needs to be considered in the assessment of the air quality impacts attributable to the proposed facility.

4.3.1.3 Slurry Pipelines

Coal-slurry pipeline systems have been used commercially in the United States since 1957. The first coal-water pipeline ran from Cadiz, Ohio, to Cleveland, a distance of 109 mi (Bertram and Kaszynsky 1986). Other coal-slurry pipelines have been constructed that extend up to approximately 310 mi (Webber et al. 1987). Topographic features may challenge slurry pipeline design in certain locations and, in some cases, reduce the relative cost-effectiveness of this transport option; for example, it has been noted that interruptions in the flow of the slurry can lead to the formation of a hard plug of coal, the removal of which is fairly problematic because it requires temporary diversion of the slurry contents into holding ponds (Webber et al. 1987). Although the conditions causing such a plug are not well understood, slurry pipelines that scale topographic inclines such as those on the islands have the potential to experience irregular flows to a greater degree than slurry pipelines along level surfaces. The likelihood of such topographically related flow problems should be considered in coal transport planning.

⁵ Conveyors have been considered for coal transport over distances up to 240 km (149 mi) (Bertram and Kaszynsky 1986).

Advantages of slurry pipelines include their ability to be used over relatively long distances and, in most cases, to transport coal at higher speeds than conveyors. Disadvantages include reliance on large quantities of water suitable for the slurry mixture,⁶ production of slurry wastewater that is too polluted to be discharged without treatment, difficulty in ascending inclines and making tight turns, and requiring coal to be crushed to a consistency that can be accommodated by the system. Various types of slurry systems exist or are undergoing development and demonstration.⁷ In addition, media other than water can be mixed with the coal in the slurry. Coal can be mixed with, among other things, liquid carbon dioxide, oil, methanol, and liquid petroleum gas (Szpunar et al. 1989).

Relative to alternative transport modes, coal slurries require considerable pretreatment of the fuel. In general, treatment involves processing the coal to the necessary consistency, mixing the coal with water to the necessary consistency, and then separating the coal and water once the slurry reaches the plant. Technologies such as a screen-bowl centrifuge can be used in the dewatering process (Szpunar et al. 1989). Treatment of the coal for transport in the slurry has the benefit of reducing the amount of precombustion processing the coal must undergo at the plant.

Due to the large capital costs that they entail, coal-slurry pipelines are generally cost-effective when used for transport of large volumes of coal (greater than 5 million tons/yr) over distances greater than 100 mi (Szpunar et al. 1989). Because the size of the islands makes transport over such distances impossible, this mode of transport is less likely to be applicable in Hawaii; however, site-specific characteristics and further technological developments may alter the feasibility of pipelines relative to other transport modes.

4.3.2 Environmental Impacts

4.3.2.1 Land-Use Requirements

Trucks. Land-use requirements for truck transport depend on whether existing roads are available for delivering coal to the generation facility. Land-use needs of truck transport will only be significant if roads to the site do not exist or if they require modification (i.e., widening) to accommodate the size of the trucks used to transport coal. The primary environmental impact of road construction is habitat destruction or displacement, with the removal of vegetation generally leading to erosion problems. It is estimated that obtaining rights-of-way for truck roads of 79-98 ft wide will require 10-12 acres/mi (Webber et al. 1987). If suitable roads to the facility site already exist,

⁶ Approximately 0.7 m³ of water is needed to transport each ton of coal (Webber et al. 1987).

⁷ The four slurry systems are discussed comparatively by Bertram and Kaszynsky (1986). We do not differentiate here between the applicability of these types to coal transport in Hawaii. The discussion here is intended to be representative of coal slurries generally.

land-use needs of truck transport would be relatively minimal. In contrast, conveyors or coal-slurry pipelines would almost certainly need to be constructed, resulting in the conversion or modification of existing land uses. It is probable that a site selected in Hawaii would have at least one preexisting road providing partial access, although some degree of road spur or extension construction would be required to provide full access to the site.

Conveyors. A review of the literature failed to yield any quantitative estimates of the amount of land that would be required for the construction and operation of a conveyor system; however, conveyors require a relatively narrow corridor along their routes. In addition, because they are less inhibited by inclines and turns, conveyors may allow a more direct route than truck transport. Consequently, depending on the width of the corridor through which the conveyor travels, conveyor systems may have smaller land-use needs than truck transport in a specific situation. In any event, it is reasonable to expect that land-use requirements would not be significantly greater than those for truck transport or coal-slurry pipelines.

Pipelines. Coal-slurry pipelines require approximately 9-12 acres/mi to construct and operate (Bertram 1983); however, although coal-slurry pipelines are more limited in slopes and turns than conveyors, the pipelines are more agile in this sense than are roads. Thus it may be possible to be more selective in choosing the route for a pipeline, compared with a road. This fact, in turn, increases the ability to minimize the adverse impacts attributable to land use. Slurry pipelines require holding ponds to accommodate occasional flow problems and general maintenance. The construction or adaption of holding ponds and also the construction of water treatment and storage facilities for the slurry mixture present additional land-use needs specific to coal-slurry pipelines. Slurry pipelines are generally buried underground; thus, initial surface impacts on vegetation and habitat are significant but could be mitigated over time.

4.3.2.2 Water Use

Water-related issues are confined to coal-water slurries. The amounts of water use and pollution associated with coal-water slurries depend on two variables: (1) the volume of coal required by the generating facility, and (2) the coal-water mixture of the slurry. Based on data from Bertram (1983), approximately 225 gal of water is required per ton of coal in a conventional coal-water slurry mixture.⁸ In some cases, the water content or combustion technology or both allow the slurry to be combusted without removal of the water. Such mixtures are referred to as coal-water fuels and require a finer coal consistency than truck or conveyor transport. Coal-water fuels require less water per ton of coal because the water content of the slurry is lower (Szpunar et al. 1989). In any event, it is important to note that

⁸ This estimate is also consistent with information in Szpunar et al. (1989) indicating that conventional coal-slurry mixtures are usually composed of a ratio of 50/50 by weight.

the water requirements of slurry mixtures are not insignificant. This fact is especially important in the context of Hawaii because water availability is limited. This problem is exacerbated by the fact that research on the use of saline water to form slurry mixtures indicates that the residues that would be left over in the coal after dewatering of the slurry mixture could lead to excessive corrosion in power-plant boilers (Szpunar et al. 1989).

In the case of coal-water fuels, water use would not be reduced, but water pollution considerations would be nearly eliminated. In the situation where the slurry mixture is dewatered prior to combustion of the coal, two options exist for handling the water once it has been separated from the slurry. On the one hand, the water can be treated and then released back into the environment. The degree to which post-slurry water requires treatment will depend on site-specific factors, including the method of discharge after treatment, municipal or state regulations (or both) governing industrial effluent discharges, and proximity to highly protected, state-designated class AA coastal waters.⁹ On the other hand, a water recirculation system can be constructed to facilitate reuse of the water. This approach prevents, for the most part, the need for water treatment. Recirculated water may require some degree of treatment, but it would be far less thorough or costly than in the aforementioned case and would require only as much treatment as is necessary to provide consistent slurry flows.

4.3.3 Costs

As the preceding discussion indicates, transport-related costs may vary considerably, both for a given transport mode and across modes. The magnitude of construction costs and O&M costs depends upon, among other things, the existing infrastructure (roads), the geographic location of the proposed site for the generating facility, the distance between the proposed site and where the coal is initially delivered to the island, and the amount of coal to be transported. In addition, various external costs are associated with each transport mode.

4.3.3.1 Construction and O&M Costs

Trucks. The costs of transporting coal by truck can be divided into separate categories, including the cost of hauling the coal to the site and the costs of developing and maintaining the roads over which the trucks travel. According to a recent report prepared by the EIA (1991), the average cost of transporting contract coal in 1987 was \$4.92/ton (1987 dollars). With adjustment for inflation, this figure increases to \$5.99/ton when measured in 1993 dollars.¹⁰ The same report estimated the price per ton per mile at \$0.19 (adjusted to

⁹ Class AA regulations are discussed in Section 4.5.1.2.

¹⁰ 1993 dollars are for January 1, 1993. Adjustment was based on the gross domestic product implicit price deflator.

1993 dollars). The report noted that truck transport costs increased by approximately 50% over the 1979-1987 period, while remaining relatively stable between 1984 and 1987 (EIA 1987). The extent to which such costs are indicative of the costs that would be incurred in Hawaii depends upon the capital and maintenance costs incurred (e.g., trucks and spare parts), fuel costs, and the distance to be traveled.

The costs of modifying or constructing and maintaining roads tend to be very site-specific. Factors influencing road construction costs include the base on which the road is built (or will be built), the type of road surface (rigid [concrete] surface versus flexible [asphalt] surface), and the overall composition of the road, including subsurface construction materials and the thickness of the pavement surface, base, and subbase. One official from the state of Hawaii's Department of Transportation estimated that repaving costs per lane per mile average \$150,000. He also indicated that the actual amount of such costs will be higher or lower than this figure depending on the factors just noted.

Conveyors. Data on the construction costs and O&M costs for conveyors tend to be proprietary and are therefore difficult to obtain. According to Szpunar et al. (1989), conveyors are most cost-effective when distances range between 1 and 15 mi and when volumes range between 2 and 10 million tons/yr. Data on conveyor system costs are presented by Tavares (1984). That study cites total annualized cost figures that, when adjusted to 1993 dollars, range between \$640,400/mi and \$2,310,500/mi for conveyor lengths ranging between 1.8 and 9.6 mi. Based on these figures, the cost of transporting 500,000 tons of coal per year via a conveyor system would range between \$1.28/ton-mi and \$4.62/ton-mi.

Care must be taken when comparing the estimated costs of conveyor systems presented here to the costs reported for truck transport. Recall that the latter cost estimates do not include all of the costs of constructing and maintaining the roads over which the trucks travel. In addition, the cost figures reported for conveyor systems do not reflect any technological (and presumably cost-saving) advances that have occurred over the last 10 years.

Pipelines. Section 4.3.1.3 noted that coal-slurry pipelines would most likely not be cost-effective in the case of Hawaii. Data presented in Szpunar et al. (1989) tend to support this assertion. To be specific, the estimates of the costs (in 1993 dollars) to transport coal-water fuels presented therein range between \$0.01/ton-mi and \$0.21/ton-mi; however, the minimum throughput and distance traveled are 3 million tons/yr and 21 miles, respectively — these values correspond to the \$0.21/ton-mi figure. Thus, reducing throughput by a factor of 6 (to 500,000 tons/yr) would increase the cost per ton-mile to \$1.26. Eliminating the mileage factor, this figure would increase to \$26.46. In addition, these costs do not include the costs of preparing the coal-water fuel mixture.

4.3.3.2 External Costs

Trucks. In addition to the direct costs associated with truck transportation — fuel, taxes, licenses, capital and maintenance expenses, and so forth — truck transport is also the source of a variety of external costs. Among these are noise, air pollution, increased congestion on roads connecting the port and generating facilities, and wear and tear on those roads. The level of external costs attributable to truck transport of coal will depend on the generating capacity of the plant in question and the amount of load served by that plant. Smaller facilities will require less coal per time period; therefore less trips will be required to maintain the desired stock of coal on-site.¹¹ In addition to increasing the costs of coal-fired generation of electricity, these external costs are a potential source of public opposition to the siting of a facility in a particular location.

Compared to conveyors and pipelines, trucks appear to generate the greatest amount of noise and air pollutants (Bertram 1983). Noise levels are a function of the type of road surface, truck type and size, driving speed, and weight of load. Trucks can be expected to generate noise levels exceeding 80 Db at 15 m and exceeding 65 Db up to 122 m from the road, depending on vegetation, terrain, truck speed, and other criteria (Webber et al. 1987). Road construction can also disturb area residents due to noise, dust, and tidal construction labor effects (Szpunar et al. 1989).

Truck exhaust, the release of coal dust, and disturbance of road dust en route to the site all contribute to increased levels of air pollution. Coal dust can be released directly from the coal load or from pieces of coal that fall from the truck during transport and then are crushed by subsequent trucks (Webber et al. 1987). Studies have found that dust levels from coal trucks have caused exceedances of federal particulate standards up to 300 m from the transportation route (Webber et al. 1987). Because coal dust is generally believed to be hazardous to human health and possibly carcinogenic, facility planners should investigate the potential health effects of coal dust before siting a coal transport route within, adjacent to, or directly upwind of any community (Webber et al. 1987).

In order to place some perspective on the potential magnitude of the noise and pollution effects of truck transport, consider the following. Assume that a 180-MW coal-fired generating facility is constructed at a site located approximately 10 mi from where coal is delivered to the island. A 180-MW plant running at an 80% load factor burns approximately 580,000 short tons of coal per year. Assume also that the coal used by the facility is to be delivered by truck, using vehicles that carry approximately 48,000 lb (24 short tons) of coal per trip. If trucks were to operate seven days per week, 24 h/day, it would be necessary to schedule an average of 2.75 deliveries per hour to ensure that the plant's fuel requirements would be met. In contrast, a facility requiring one-fifth as much coal would require an average of one delivery approximately every two hours.

¹¹ Note that smaller facilities will also require less land to store required coal reserves.

The wear and tear on road surfaces attributable to increased truck traffic reduces the effective life of the road surface. As a consequence, the road must be resurfaced at more frequent intervals. The increased maintenance costs resulting from the shortened maintenance schedule represent a potential external cost attributable to increased truck traffic. Fuel taxes and licensing fees are used, at least in part, to finance road maintenance costs. Thus, to some extent, these costs are internalized (i.e., they are borne by the producer [and consumer in the form of price increases]) and are therefore factored into the decision-making process; however, such fees are only loosely related to the costs of wear and tear on roads caused by heavy trucks (Small et al. 1989). To the extent that there is a divergence between the fees collected and the costs attributable to the truck traffic, these costs are not factored into the decision of whether to use truck transportation. In this sense, these costs can be treated as external to the decision-making process. A technical discussion of a method that can be used to assess the road wear-and-tear costs attributable to truck traffic is presented in Appendix C.

Conveyors. External costs attributable to conveyors include some amount of noise, adverse effects on visibility, and possibly air pollution. The amount of noise associated with conveyors is less than that for truck transport. Nonetheless, background levels of noise would increase in the vicinity of the conveyor system. Visibility would be adversely affected to the extent that the conveyor system intrudes on the natural environment, obstructing or otherwise interfering with certain views.

Conveyors are likely to generate more air pollution than slurry pipelines but less than trucks. In addition, covered conveyors will release less pollution than open conveyors. Much of the coal dust associated with conveyors results from the loading and unloading of the coal to and from the conveyor. The proportion of dust attributable to these activities increases as the length of the conveyor decreases.

Pipelines. The primary external costs attributable to coal-slurry pipelines result from their construction. As was noted earlier, burial of the pipeline results in the disruption of wildlife habitat. In addition, noise and dust can be a problem during the construction phase; however, over time, many of these adverse effects can be mitigated to varying degrees. Pipelines have an advantage over conveyors and roads in this regard.

Coal-slurry pipelines will not generate air pollution en route, because the mixture of coal with water will capture any coal dust or particles. In fact, there is a trade-off in the case of slurries, in which water pollution accounts for any pollutants that may otherwise have become airborne. Water pollution issues associated with slurries are discussed in Section 4.3.2.2.

4.3.4 Impact Mitigation Recommendations

While what role fuel transport will play in perceptions of the impacts of a proposed facility is unclear, efforts should nonetheless be undertaken to minimize the sum of internal and external costs attributable to each transport mode. Some of the mitigation options that are relevant to planning coal transport to a facility in Hawaii are discussed subsequently.

4.3.4.1 Routing Decisions

The routing impacts of a road, conveyor system, or coal-slurry pipeline will depend on a number of factors. These factors include (1) the degree to which construction and use of the proposed route disrupts existing activities (such as traffic patterns), (2) the effect the proposed route would have on such activities as recreation and tourism (and the corresponding level of enjoyment of the natural environment), (3) the extent to which the route degrades the environment physically (resulting in adverse effects such as habitat loss for certain species of wildlife), and (4) adverse impacts on air quality (such as ambient pollution concentrations or visibility). Careful planning based on reasonably anticipated impacts can reduce the probability of cost-ineffective outcomes.

Alternative transport modes and routes should be identified to reveal potential trade-offs with respect to external costs; for example, trucks might be able to use existing roads to transport coal to the facility, while construction of a conveyor system would entail up-front external costs due to construction, disturbance of wildlife habitat, and so forth; however, over the long run, it may well be that the external costs attributable to truck transport would exceed the external costs, both up front and over the long term, resulting from the conveyor. Alternative transport modes should also be compared with respect to their likely impacts on visibility, recreation, and community disruption.

4.3.4.2 Operational Changes

Certain operational changes can be implemented to reduce the environmental impacts associated with coal transport; for example, fugitive coal dust emissions can be minimized by covering conveyors or trucks. This reduces both the risk of potentially hazardous coal dust becoming airborne and the risk of some degree of coal escape during transport. Second, trucks can be driven at lower speeds in order to mitigate noise and dust generation, minimize habitat disturbance, and reduce wear on roads (Webber et al. 1987). Additional equipment may also be employed to minimize potential undesirable environmental impacts resulting from the transport of coal to the generating facility. In the preparation of slurries and in the loading, unloading, and any necessary treatment processes for trucks, pipelines, and conveyors, technologies should be sought that reduce noise, dust, population and habitat disturbance, and other identifiable environmental impacts.

4.4 PUBLIC PERCEPTIONS: ACCEPTANCE VERSUS REJECTION

A growing body of research has developed in recent years that examines individuals' perceptions of what are commonly termed "noxious facilities." Noxious facilities include, among others, waste disposal sites (both hazardous and nonhazardous), nuclear power plants, sewage treatment plants, and conventional (e.g., coal- and oil-fired) power generating plants. While such facilities differ with respect to the characteristics that classify them as noxious — risk, odor, pollution, etc. — they share a common attribute, namely, an aversion on the part of society to having such facilities located close to where individuals live. The so-called not-in-my-backyard (NIMBY) syndrome has grown in importance, making the siting of such facilities much more difficult than was the case in years past.

4.4.1 Public Attitudes toward Noxious Facilities

Various factors, such as population density, ambient environmental conditions, existing commercial and industrial operations, and the tastes and preferences of affected individuals, influence how the public will react to a specific facility siting proposal; however, the relationship between each of these variables and the public's response to a particular proposal is not immediately obvious; for example, a candidate site that is located in a sparsely populated region may affect relatively few individuals. Nonetheless, the prevailing ambient environmental conditions (e.g., a lack of anthropogenic sources of pollution) may be a prime motivation for resistance to any type of development that would alter such conditions. Note that in this type of situation, the individuals opposed to the proposed site do not have to be affected directly (i.e., they need not live in the vicinity of the proposed site). Instead, opposition could come from public interest groups that oppose such developments in the interest of preserving undeveloped areas. As another example, individuals might strongly oppose a proposal to replace an existing facility that is about to be retired with a new generating facility. In this case, opponents might view the proposal as an opportunity to eliminate an undesirable land use altogether.

Coal-fired generating facilities possess a number of undesirable characteristics. In general, coal-fired generating facilities are viewed as noisy and dirty and a source of a variety of pollutants. In addition, as was discussed previously, depending on the mode used to transport fuel to the facility, considerable external costs may be imposed on the existing infrastructure and surrounding environment. This would be especially true in the case of truck transport in populated areas where road use is already at or near capacity. These perceptions were reflected in responses to the survey conducted as part of the workshop sponsored by DBEDT in the fall of 1992 (DBEDT 1992). When respondents were asked to describe their preferred vision of the energy sources that would be in use in the future, coal was identified as the *least-preferred* alternative energy source. In addition, coal was *not* identified as a means to diversify the current mix of energy sources in Hawaii. The number of respondents to the survey was relatively small — 57 questionnaires were completed, for a response rate of 27%. Nonetheless, the results provide an indication of how those members of the public who are more likely to be active participants in the debate over alternative

energy strategies might respond to proposals to site coal-fired generating facilities in specific locations.

Much of the research on the public's perceptions of noxious facilities has focused on the siting process — in particular, why efforts to site such facilities often fail and what can be done to improve the overall process. The latter issue is addressed in Section 4.4.4. With respect to the former, O'Hare et al. (1983, p.3) contend that:

. . . the facilities siting problem is characterized by two important propositions:

1. Inadequate mechanisms exist at present for the parties affected by a new facility proposal to share in the benefits the project will provide to society as a whole, or to effectively negotiate the size of their share.
2. Much of the facility siting debate is ignorant or ill-informed because the social, political, and economic structures by which information is made available obstruct its efficient use or generation.

According to O'Hare et al. (1983), attempts to improve the siting process are often based on a misunderstanding of how people behave in this process. O'Hare et al. (1983) identify four categories of such misperceptions: (1) the lawyer's fallacy, (2) the engineer's fallacy, (3) the planner's fallacy, and (4) the economist's fallacy. These categories are named according to the basis on which they are founded; for example, the lawyer's fallacy asserts that the siting process is simply a series of legal tests and that so long as the appropriate permits are obtained and actions are adequately defended, the proposed project will be able to move forward. The engineer's fallacy is that people simply need to be convinced that the proposed site is, in fact, the best site on technical grounds, and the project will be able to proceed. The planner's fallacy is that disagreements over proposed siting decisions can be resolved through increased participation in the overall process. The economist's fallacy is the assumption that, in order to appease the opponents of a proposed facility, it is simply a matter of identifying what constitutes an adequate (sufficient) amount of compensation for such individuals.

The fallacies described previously underscore the difficulties that may be encountered in efforts to overcome public opposition to a proposed site. Although provision of information to the public is an essential part of the siting process, information cannot be expected to resolve all of the objections to a proposed site (the engineer's fallacy). In addition, efforts to outmaneuver the opponents of a proposed site through the use of legal tactics may simply strengthen the opponents' resolve. The suggestion that increased participation can resolve most disagreements over a proposed siting decision fails to recognize differences in incentives that individuals have to participate in the debate. As O'Hare et al. (1983) correctly note, the incentive to participate in the siting process is tempered by the benefits and costs of doing so. Thus, it may be that individuals who stand to gain or lose little on an individual basis will tend to avoid involvement in the process even though, as a group, the benefits or costs are quite high.

The question of whether compensation could be used to satisfy opponents is of particular interest in the case of Hawaii. To be specific, the selection of many potential sites for generating facilities or transmission lines may result in significant adverse effects on the natural environment or cultural resources. In such cases, it is quite possible that opponents would refuse to put a price on such effects, so that no amount of compensation would be considered adequate.

Analysis of the types of problems that have arisen in the siting process has yielded a number of different proposed strategies for improving the efficiency of the process; for example, a number of reforms have been instituted over time that were designed to address a commonly agreed-upon set of "problems" associated with the siting process. These problems include (1) factors that decrease the efficiency of the siting process, (2) factors that decrease the efficiency of the outcomes of the process, and (3) factors that decrease the fairness or equity of the process (O'Hare et al. 1983). O'Hare et al. (1983) have categorized the various reforms according to the problem that they were designed to address. The categories, which are listed in Table 4.2 (along with examples of each), include (1) reforms designed to expand formal public participation, (2) reforms designed to lead to better informed decision making, (3) reforms that create new regulations that are, in turn, designed to guarantee that the "right" decision-making criteria are used, and (4) reforms designed to increase procedural efficiency (O'Hare et al. 1983). O'Hare et al. (1983, p. 64) maintain that many of the reforms that have been applied to the siting process have, in fact, failed, stating that

The central defect of these reforms is that each is based on one or another of the widespread misapprehensions about the siting process itself, or about how people behave in it, . . . If the theory behind a reform does not correctly describe the real world, the process will not change in the way its designers intended, and the effects that do occur are as likely to be damaging as beneficial.

As discussed in Section 4.4.4, recent proposals to improve the facility-siting process have focused on the importance of information and the role of compensation. It might appear that such proposals are simply manifestations of the planner's fallacy and the economist's fallacy; however, this is not the case. Instead, such proposals advocate a comprehensive approach that attempts to address, within a multidisciplinary context, the concerns (e.g., technical issues and external costs) that dominate the debate over where certain facilities should be located.

4.4.2 Case Studies

The evidence on the public's attitudes toward the siting of coal-fired power plants is mixed. Not surprisingly, proposals to site facilities in locations where coal plants already exist or in areas close to where coal is mined tend to meet with less opposition, all else constant. In contrast, proposals to site coal-fired facilities in environmentally sensitive areas tend to meet with considerably more opposition. The following case studies illustrate the range of previous reactions to proposed facilities.

TABLE 4.2 Summary of Siting Process Reforms and Examples

Type of Reform	Examples
Reforms designed to expand formal public participation	Public hearings; public interest advocacy
Reforms designed to lead to better informed decision making	Requirements for environmental impact statements or environmental assessments; Council on Environmental Quality regulations
Reforms that create new regulations that are, in turn, designed to guarantee that the "right" decision-making criteria are used	More stringent standards (e.g., laws and regulations); selection of sites by government entities; state overrides of other state or local rulings
Reforms designed to increase procedural efficiency	Expanded powers for oversight agencies; one-step regulatory process (consolidation of review and permit authorities into a single agency); changes in operating procedures

Calzonetti et al. (1989) provide two examples of how the public has reacted to the proposed siting of coal-fired facilities in different locations. The first example describes efforts undertaken by the state of Maryland in 1979 to locate a site for a coal-fired power plant that was to be built at some future date. Based on extensive study and on town meetings, the state selected Pinesburg, Maryland, as the preferred site for a coal-fired generating plant. The state's initial contacts with local officials representing the population in the vicinity of the proposed site were met with what appeared to be strong support. The proposed facility was expected to generate a large amount of tax revenue (\$28 million/yr) and new jobs, but no noticeable adverse impacts (Calzonetti et al. 1989).

In the course of developing plans to acquire the land required for the site, affected residents became aware of the specific intentions of the siting program. Two of the affected residents who were made aware of the state's plans organized an ad hoc citizens' group to protest the proposed plan. Among other things the citizens' group distributed fact sheets informing people of a variety of potential impacts associated with the proposed facility, including an increase in respiratory and allergy problems, adverse aesthetic impacts, and reductions in property values. The citizens' group also maintained that the new site was not needed because electricity demand projections were down and additional capacity was not needed. Ultimately, the citizens' group succeeded; the state discontinued its efforts to gain approval of the proposed site.

The second example described in Calzonetti et al. (1989) involves a coal-fired power plant that was built by American Electric Power Co. (AEP) near New Haven, West Virginia. The decision to build the plant was announced at a joint news conference held by the governor of West Virginia and the chairman of AEP in January 1974. In addition to emphasizing the benefits that the proposed plant would generate for the local economy at the

news conference, AEP held a town meeting shortly thereafter to answer questions about the proposed plant. Overall, the proposal was met with enthusiasm by the local community, and the project proceeded with very few problems. The plant went on-line in 1980. According to Calzonetti et al. (1989), a similar story could be told for most power plants sited in West Virginia.

The principal factors distinguishing these two examples are the location of the proposed plant relative to the mine mouth and the resulting prospects for employment in the region. In the case of West Virginia, construction of electric power plants means not only jobs at the generating facility, but also continued and possibly additional employment at the coal mines. As such, the perceived benefits are considerable. In contrast, the Pinesburg case illustrates the situation in which individuals perceive relatively few benefits from the proposed facility and a number of potential costs in the event that the plant is actually built.

A third example, which was cited by O'Hare et al. (1983), involves efforts by the town of Searsport, Maine to attract an energy-related facility to their area. In all, attempts were made to site three different facilities between 1971 and 1977 — an oil refinery, a nuclear power plant, and a coal-fired power plant. Environmental concerns effectively eliminated the proposed refinery. Efforts to site the proposed nuclear plant were confounded by inconsistent information on where the preferred site was actually to be located and concerns about safety and the actual need for such a facility. When Central Maine Power proposed to construct a 600-MW coal-fired facility in 1977, state officials questioned both the need for the facility and its ability to comply with environmental standards. This project was also ultimately rejected. This example illustrates the effects that inadequate information and mistrust on the part of the public can have on the siting process. The example also underscores the importance of establishing a legitimate and defensible need for the proposed facility as a first step toward gaining the public's approval.

4.4.3 Costs

4.4.3.1 Utility/State Perspective

Viewed from the perspective of the proponents of a proposed site (e.g., the utility that is planning to build and operate the proposed facility), public opposition implies increased costs to construct and operate the proposed facility. In addition to legal fees, costs will be incurred to conduct feasibility and impact studies for the proposed site. As is discussed in Section 4.5, permitting requirements are generally quite extensive. Public opposition generally results in a number of outcomes that increase costs, including delays in construction that increase financing costs, and challenges that force the utility to provide additional evidence in support of its claims that the proposed facility will not result in undue adverse impacts on the environment or on health and well-being. The entity that is planning to construct the proposed facility will incur some amount of costs prior to the announcement of the proposed site in an effort to minimize the total amount of such costs that are incurred; however, beyond statutory requirements that dictate certain actions (e.g., preparation of an

environmental assessment or impact statement), it is difficult to determine the amount of effort that should be expended up front.

4.4.3.2 Public's Perspective

When confronted with the possibility of having a noxious facility located nearby, members of the public tend to think in terms of the external costs that the proposed facility will impose upon them. This response was reflected in the reaction of the residents in the example of Pinesburg, Maryland, described previously. External costs, including the adverse effects of pollution from the facility and the possibility that property values in the vicinity of the proposed facility would decline, were cited as good reasons for opposing the facility's siting.

It may well be that individuals who expect to be adversely affected by the proposed siting might benefit as well. In the case of an electric generating facility, such benefits might include reduced rates for electricity, an increase in the level of reliability of the utility system, and an increase in the tax base that benefits local property owners; however, from the individual's perspective, such benefits might appear relatively small. In addition, the perceived costs may appear to more than offset any benefits that might accrue. As noted by O'Hare et al. (1983, p. 68), "the *per capita* costs that a facility threatens to impose on a small number of people — especially the social [external] costs imposed on people who live near the site — tend to be large for groups that are numerically small."

4.4.4 Impact Mitigation Efforts and Potential Impacts on Public Perceptions

In contrast to the types of reforms described previously, O'Hare et al. (1983) argue that what is needed to improve the effectiveness of the siting process is a system of compensation, or side payments. Compensation serves to change the alternatives faced by individuals who believe that they will be adversely affected by the proposed facility siting. In effect, compensation increases the amount of benefits that will accrue to those individuals and offsets some (or all) of the external costs. The types of compensation that can be used include the following:

- Money in the form of reduced tax rates for local citizens or an increase in local services (as well as direct payments to individuals);
- Conditional compensation (e.g., a guarantee to compensate property owners for any decline in property values attributable to the proposed facility);
- In-kind compensation, such as the development of recreational opportunities to replace activities displaced by the proposed facility;

- Protection, such as the installation of safety equipment at the site; and
- Impact mitigation (O'Hare et al. 1983).

One of the major challenges in implementing a compensation scheme will be determining what constitutes the "correct" amount of compensation. Several studies, including those by Mitchell and Carson (1986), Kunreuther and Kleindorfer (1986), and Swallow et al. (1992), have addressed the issue of determining how much compensation should be forthcoming and who should receive it. A discussion of the technical features of the various proposed compensation schemes is beyond the scope of this discussion; however, it is important to recognize that compensation schemes are gaining widespread recognition as a means to facilitate the siting process.

A more recent proposal for improving the siting process is described in Swallow et al. (1992). According to these authors (Swallow et al. 1992, p. 287), the objective of the proposed process is

to minimize the social costs of providing a given, locally undesirable facility. In order to rank sites according to social costs, the siting process must compare bundles of impacts associated with each alternative site. These impacts arise in three dimensions: the existing technology for producing the proposed facility, impacts on regional public good resources, and demand for compensation of the local community.

The study by Swallow et al. (1992) builds upon the analysis of O'Hare and others (1983) and proposes a three-stage approach to the siting process. The first stage involves identification of a long list of candidate sites that are technically suitable for the proposed facility. An important characteristic of this stage of the process is that it does not include consideration of such factors as the relative costs — internal or external — of the different sites, political considerations, and so forth. (These factors are considered in stage 2.) Instead, the analysis in stage 1 is designed to screen candidate sites for compliance with constraints based on technical requirements, such as the potential for violation of pollution standards and minimal resource requirements.

In stage 2 of the process, the social suitability of each of the sites identified in stage 1 is calculated and compared across sites. The analysis in stage 2 requires that the public's preferences with respect to trade-offs among site characteristics be evaluated. These trade-offs are based on the amount of compensation each individual would be willing to accept as compensation for the adverse effects in question. Willingness to accept compensation can be estimated with the use of a contingent valuation survey. This technique involves the use of a survey instrument to elicit individuals' valuation of how much money

they would require (be willing to spend) to be compensated for (to realize) the proposed action.¹²

The evaluation of the trade-offs associated with each site on the long list is then used to generate a short list of socially "most preferred" sites (Swallow et al. 1992). In effect, stage 2 requires that the different external costs associated with each of the proposed sites be identified and described, quantitatively or qualitatively. A list of weights must then be developed that can be applied to each characteristic of interest so that a single score can be derived for each site. This score is then used to rank the sites on the long list developed in stage 1. A reduced number of sites are selected for further consideration based on this rank ordering.

The third stage in the siting process involves two steps: (1) selection of the preferred site, and (2) determination of the compensation package that will be acceptable to the host community (i.e., individuals adversely affected by the proposed siting). As described in Swallow et al. (1992), the compensation package could be determined using some form of an auction mechanism. Essentially, the goal is to identify the site on the short list that requires the least amount of compensation. Selection of this site would then result in the minimum total cost attributable to the siting of the proposed facility. Requiring that the sites on the short list that are not chosen share equally in the cost of providing the compensation to the site with the lowest bid would create an incentive for sites to avoid overstating the minimum amount of required compensation.

The approach summarized here is designed to improve the quality of the outcomes of the siting process. In particular, this approach provides for objective consideration of the technical merits of various candidate sites independent of qualitative considerations; however, qualitative considerations are also given full consideration. In addition, the fact that the siting of noxious facilities will impose costs on certain individuals is explicitly recognized. The proposal to compensate individuals adversely affected by the proposed siting reflects both economic considerations — by increasing the chances that resources will be allocated efficiently — and also concerns about equity.

Whether such an approach would work in Hawaii remains to be seen; for example, as was noted previously, compensation may not be a relevant consideration where certain natural or cultural resources are concerned. Nonetheless, careful consideration should be given to adopting an approach that incorporates similar elements. The experiences with siting coal-fired generating facilities in other locales suggest that a proposal will have to be well conceived and adequately address the types of concerns that have been identified here to have a reasonable probability of success.

¹² For a discussion of the contingent valuation method, see Mitchell and Carson (1989) and the references cited therein. More recent discussions of the strengths and weaknesses of contingent valuation include Kahneman and Knetsch (1992), Smith (1992), and Harrison (1992).

4.5 LEGAL/REGULATORY BARRIERS

In recent years, the impact of industrial development on environmental quality has been increasingly regulated. New facilities are subject to the requirements of the Clean Air Act, the Clean Water Act, the Resource Conservation and Recovery Act, and the Coastal Zone Management Act, as well as a host of other federal and state environmental laws. This section identifies areas of regulatory interest and concern that have the potential to affect the siting and permitting of a new coal-fired generating facility in Hawaii.

4.5.1 Environmental Quality

4.5.1.1 Clean Air Act

The Clean Air Act¹³ establishes national ambient air quality standards (NAAQSs) for six common or "criteria" air pollutants¹⁴ and divides the nation into areas of attainment, nonattainment, and unclassifiable with respect to those standards. Hawaii is in attainment with the NAAQSs¹⁵ and is therefore subject to the rules of the program for prevention of significant deterioration (PSD),¹⁶ which was established by the 1977 amendments to the Clean Air Act. Among other things, the PSD program establishes standards for maximum allowable increases in emission concentrations relative to baseline levels in attainment areas.¹⁷ Maximum allowable emission increases are often termed "increments," because they refer to the incremental increases in ambient air pollutant concentrations allowed under the Clean Air Act. Additional PSD provisions exist for certain natural and wild areas designated for more stringent protection under the Clean Air Act.¹⁸

Proposed major facilities and modifications to existing major facilities in attainment areas must obtain PSD permits prior to their construction. In order to obtain permits, applicants must prove to the satisfaction of the state permitting agency that their proposed action will not exceed or contribute to the exceedance of either the maximum allowable

¹³ The Clean Air Act Amendments of 1970, P.L. 91-604, 42 USC 7401 (1970), as amended by the Clean Air Act Amendments of 1977, P.L. 95-95, 42 USC 7401 (1977), and the Clean Air Act Amendments of 1990, P.L. 101-549, 42 USC 7401 (1990).

¹⁴ Section 108 of the Clean Air Act. These include sulfur dioxide, carbon monoxide, nitrogen dioxide, lead, ground-level ozone, and particulate matter.

¹⁵ 40 CFR 81.312, as amended by 56 FR 56746 (1991).

¹⁶ Section 160 of the Clean Air Act.

¹⁷ Section 163 of the Clean Air Act.

¹⁸ Section 163B of the Clean Air Act, for example, establishes provisions in which findings of adverse impacts from the proposed action can impede the permitting process. Areas afforded the most stringent protection under the act are termed Class I areas and are discussed subsequently.

increases in ambient emission concentrations, the NAAQS, or any other standard under the Clean Air Act.¹⁹ Site assessment should consider emissions from adjacent or nearby facilities that may be exacerbated by a new coal-fired generation plant, possibly to the point of increment exceedances, since this will complicate the permitting process. Offsets may be used in some cases to reduce the impact of new sources in areas where increment consumption has already occurred and ambient pollutant concentrations approximate their legal limits.²⁰

Federal and Hawaiian ambient air quality standards (AAQSs) are summarized in Table 4.3. As the data in Table 4.3 illustrate, Hawaiian AAQSs are more stringent than the NAAQSs for carbon monoxide, ozone, and nitrogen dioxide and provide qualitatively different rules for particulate matter.²¹ Consequently, state law, as opposed to its federal counterpart, will constrain the emissions of airborne pollutants from coal-burning facilities. The state permitting agency can be expected to be particularly interested in the tendency of emissions of these pollutants to consume available increments.

The 1977 Clean Air Act Amendments further subdivided the nation within the category of attainment areas into class I, class II, and class III areas.²² Class I areas consist of attainment areas with the most pristine air quality, primarily national parks and wilderness areas, and are provided the greatest degree of protection under the Clean Air Act.²³ There are two class I areas in Hawaii: Haleakala National Park, located on the southeast portion of Maui, and Hawaii Volcanoes National Park, located on the south-central portion of Hawaii Island. Together the parks cover 244,237 acres. Prevailing wind patterns have the potential to disperse emissions from generating facilities on these two islands to the parks. Air quality modeling would be necessary to discern the probability of impacts to the parks from power plant emissions on the islands. Although other islands and areas will present their own siting and permitting obstacles, the islands of Maui and Hawaii can be expected to pose particularly problematic air quality issues due to the presence of the highly

¹⁹ Section 165(a) of the Clean Air Act. The issue of emission loading is already constraining industrial development in Hawaii. In March 1993, the state determined that SO₂ emissions around Campbell Industrial Park were approximating the federal limit and that no additional facilities would be permitted in the park unless offsets could be obtained that ensured no net increase in SO₂ emissions (*Honolulu Advertiser* 1993).

²⁰ Offsets are obtained when new sources finance emission reductions at existing sources to ensure that the new source does not cause a net increase in emissions. By using offsets, new sources are often able to overcome some of the permitting difficulties that accompany attempts to site an emitting facility in an already-developed area.

²¹ Hawaii, 1986, "Ambient Air Quality Standards," Code of Rules and Regulations, Title 11, Chapter 59.

²² At present, there are no areas designated as Class III.

²³ Sections 162 and 169A of the Clean Air Act.

TABLE 4.3 National versus Hawaiian Ambient Air Quality Standards

Criteria Pollutant	Standard	NAAQS ^a	Hawaiian AAQS ^b
SO ₂	Primary Secondary	80 µg/m ³ (c)/365 µg/m ³ (d) 1,300 µg/m ³ (e)	80 µg/m ³ (c)/365 µg/m ³ (d) 1,300 µg/m ³ (e)
Particulate matter	Primary Secondary	150 µg/m ³ (d)/50 µg/m ³ (c)	60 µg/m ³ (f)/150 µg/m ³ (d) 100 µg/m ³ (g)
Carbon monoxide	Primary	10 mg/m ³ (h)/40 mg/m ³ (g)	10 mg/m ³ (g)/5 mg/m ³ (h)
Ozone	Primary and secondary	0.12 ppm (235 µg/m ³) ⁱ	100 µg/m ³ (g)
Nitrogen dioxide	Primary and secondary	0.053 ppm (100 µg/m ³) ^c	70 µg/m ³ (c)
Lead	Primary and secondary	1.5 µg/m ³ (j)	1.5 µg/m ³ (j)

^a NAAQSs reflect standards as of July 1, 1991 (40 CFR 50).

^b Hawaiian AAQSs reflect standards as of April 14, 1986 (Hawaii Code of Rules and Regulations, Title 11, Chapter 59).

^c Annual arithmetic mean.

^d Maximum 24-h concentration.

^e Maximum 3-h concentration.

^f Annual geometric mean.

^g Maximum 1-h concentration.

^h Maximum 8-h concentration.

ⁱ Maximum 1-day/yr exceedance by hourly average ≥ 1 .

^j Maximum arithmetic mean (average quarter).

protected national parks. Some of these problems may be mitigated by careful selections of site, control technology, and fuel that minimize air quality impacts to the parks. Modeling of air dispersion patterns and facility emissions at alternative candidate sites will indicate sites that should be ruled out due to more likely adverse impacts.

All other areas of the islands fall into class II, which makes them subject to PSD provisions but not to the special protection programs afforded to class I areas. While concerns about visibility on the mainland have primarily affected facilities near class I areas, such concerns can be expected to be less dependent on proximity to class I areas in Hawaii. There are several reasons for this. First, Hawaii's reliance on tourism as its primary industry demands relatively pristine air quality and precludes visible anthropogenic emissions. Second, Hawaii's residents place a high value on the natural quality of the island environment and object to both visible emissions and degradation of visibility because it is perceived as an indicator of air quality generally. Finally, the fact that state air pollution standards are more stringent than national standards suggests that state permitting officials may be more willing to challenge permit applications and their attendant impact assessments. A review of permit proceedings over the past few years may reveal trends in the state's treatment of permit applications and methods for avoiding some of the impediments encountered in the siting/permitting process.

The U.S. Environmental Protection Agency (EPA) identifies two forms of visibility degradation: regional haze and plume blight. Regional haze is defined as "widespread, regionally homogeneous haze from a multitude of sources which impairs visibility in every direction over a large area."²⁴ The geography of the islands and the prevailing winds from the northeast that generally carry emissions out to sea diminish the likelihood of problems of regional haze in Hawaii; however, in some cases, emissions may stagnate in mountain valleys, causing potential environmental degradation and health problems among area residents. The probability of regional/mountain valley haze will depend on facility size, proximity to valleys, and topographical features generally. Plume blight is defined as "smoke dust, colored gas plumes or layered haze emitted from stacks which obscure the sky or horizon and are relatable to a single source or small group of sources."²⁵ Plume blight will likely occur at greater frequencies than will regional haze because prevailing winds and the presence of mountains may cause visible emission plumes to be carried up mountain slopes. Again, the vast majority of emissions can be expected to be carried out to sea and dispersed.

A recent study found that an increasing number of PSD permit proceedings have been affected by perceived impacts on visibility and other air-quality-related values (Loeb and Elliott 1993). In many cases, applicants have been forced to make concessions to permitting authorities, including changes in capacity, fuel type or grade, offset arrangements, site location, and control technology changes; however, the study found that, in one case, the applicant raised air-quality impact issues without heightening concerns by openly addressing

²⁴ 45 FR 80,085 (1980).

²⁵ 45 FR 80,085 (1980).

the likely emissions from the facility and working with the community to devise acceptable strategies for abatement. Interestingly, an applicant that goes out of his way to prove air quality impacts and works subsequently to mitigate them appears to elicit more favorable reactions by local populations and permitting officials than if he had worked to disprove perceptions of adverse impacts. Permit applicants may benefit from the lessons provided by this example.

The Clean Air Act Amendments of 1990 established a program for the significant reduction of emissions of SO₂ and nitrogen oxides, which are precursors of acid precipitation. This program is focused on the electric utility industry, which accounts for the majority of emissions of these pollutants in the United States. While most of these requirements apply to existing sources, new sources will also be affected by a large number of provisions of the acid rain program. An enumeration of applicable requirements is given here, although a detailed analysis of applicable acid rain program requirements will be necessary in later stages of the facility siting/planning process, particularly in preparation for permit application.

First, all major sources in Hawaii will be subject to the SO₂ and nitrogen oxide emissions limits of phase II of the Clean Air Act's acid rain program.²⁶ Separate limits are established for different classes of utility units in Section 405 of the Clean Air Act. Second, new source performance standards (NSPSs) contain technology-based emission requirements for new or modified stationary sources of various types. Third, specific provisions for new sources in Title IV will present performance and technology standards additional to those set out in phase II.

Finally, Section 112(n)(1) of the Clean Air Act requires the submittal to Congress of three reports on hazardous air pollutants emitted by electric utility steam generating units. Two of these studies are due by November 1993, and one is due the following November, generally focusing on levels of utility hazardous air pollutant emissions and their health and environmental impacts. Additional regulations may be promulgated as a result of the findings of these reports; thus, site assessment activities should review these findings.

4.5.1.2 Water Pollution Control

Site availability also may be constrained by certain water use designations, which are set out in the Hawaii Water Quality Standards,²⁷ which apply to coastal waters

²⁶ See, generally, Sections 404 and 405 of the Clean Air Act. Phase II refers to a period of SO₂ and nitrogen oxide control beginning January 1, 2000 and affecting the vast majority of electric utility units nationwide. Phase I begins January 1, 1995, and affects the 261 units that had the highest rates of emission of these pollutants in the baseline period (an average of 1985-1987 emissions relative to fuel consumption as measured in million Btu).

²⁷ Hawaii Administrative Rules, Title 11, Chapter 54 (Water Quality Standards).

surrounding the islands. These designations effectively supplement the state's Land Use Law²⁸ as a form of water zoning regulation and have the ability to preclude development on adjacent coastal areas. A coal-fired generating facility may be dependent on water as a coal transportation medium (both to the island and as a slurrying agent), as a waste transportation medium (if facility waste requires mainland disposal), and for cooling and other operational activities. In addition, precipitous air emissions from the facility may be carried by prevailing winds to class AA waters or, less directly, deposited into island rivers that flow into class AA waters. In any event, the potential for adverse impacts on protected coastal waters from utility particulate or precipitous emissions (or both) should be assessed and avoided. To the extent possible, given inevitable reliance on large quantities of water, candidate sites should be identified in areas remote from class AA-designated coastal waters. Water use-related conflicts will be reduced as proximity and impacts to class AA waters decrease.

Section 112(m) of the Clean Air Act requires the EPA to study the extent of atmospheric deposition of hazardous air pollutants in the Great Lakes and other coastal waters and to report to Congress on its findings by November 1993.²⁹ Like the hazardous air pollutant studies mentioned previously and depending on the pollutants studied and the findings of the assessment, the EPA Administrator may promulgate additional regulations by November 1995 to protect coastal waters, among other estuaries.³⁰ The findings of the administrator's study should be considered in conjunction with other state and federal coastal water regulations during the site assessment process because promulgation of additional controls will increase the number of siting constraints.

4.5.1.3 Waste Management Requirements

Waste management considerations will depend on the volume and characteristics of waste produced by the facility, as well as the municipal, state, and federal regulatory context for waste management. The waste volume and characteristics will be a product of capacity, control technology, and fuel type and grade. Regulatory uncertainties include the designation of waste as hazardous or nonhazardous, constraints on the islands' waste disposal options for different categories of wastes, and availability of beneficial applications of combustion wastes in Hawaii. Additional issues stem from the need for transport of the waste to the mainland, which will be necessary if treatment, disposal, or commercial applications on the island do not accommodate the total volume of waste produced. These and additional issues are discussed in detail in Section 3 of this report.

²⁸ Hawaii Revised Statutes, Title 13, Chapter 105 (Planning and Economic Development).

²⁹ The EPA Administrator is given discretionary authorization to assess the extent of deposition of other pollutants as well [Section 112(m)(1)].

³⁰ Section 112(m)(6) of the Clean Air Act.

4.5.2 Permitting Requirements

Permit applicants will be constrained by requirements at both the state and federal levels.³¹ The Clean Air Act contains informational and procedural requirements for permit applicants and for PSD permit proceedings generally.

All proposed major sources must obtain a PSD permit prior to construction. Above all, applicants must prove to state permitting agencies that their emissions will not cause or contribute to exceedances of maximum allowable increment levels, NAAQS, or any other emission or performance requirement.³² Modeling is required to determine the air quality impacts of facility-related regional growth³³ and is generally necessary to disprove any potential adverse impacts.

Rules Governing Public Participation in the Siting Process. New or modified major emitting facilities are required to apply to state permitting agencies,³⁴ in this case the Hawaii Department of Health, for PSD permits. The Hawaii Air Pollution Control Act³⁵ contains provisions for public involvement in the permitting process that are very similar to those specified in the federal Clean Air Act. The director of the state Department of Health is required to notify the public of any major source permit application involving air pollution, and the director is allowed to hold public hearings on the application before making a final determination.³⁶ Numerous additional requirements provide for public participation, communication, and comment.³⁷ These include issuance of detailed public notices of the permit application to residents of both the area of the proposed facility and areas of potential impacts from the proposed facility, and provision of a public comment period of at least 30 days of public notice, which may be extended at the director's discretion. Applicants can expect the public to be well informed about proposed facilities, both because of the director's notices and the considerable public interest that appears to be created by development proposals in the state.

³¹ The permitting requirements discussed in this section apply only to new major sources, as defined by Section 169 of the Clean Air Act. Additional requirements may exist in state and federal law for permitting generally, although they have been omitted to focus on the specific requirements for new coal-fired generation facilities of approximately 100 to 200 MW in Hawaii.

³² Section 165(a)(3) of the Clean Air Act.

³³ Section 165(a)(6) of the Clean Air Act.

³⁴ Section 165 of the Clean Air Act.

³⁵ Hawaii Revised Statutes, Title 19, Chapter 342B (Air Pollution).

³⁶ Section 342B-4(d) of the Hawaii Air Pollution Control Act.

³⁷ Section 342B-5(h)(1) of the Hawaii Air Pollution Control Act.

Difficulties in obtaining PSD permits due to perceived adverse impacts derive from a number of factors, including ambient air quality, the existing number of sources and their emissions, the capacity of the proposed unit, the presence of environmentally sensitive areas, and other factors related to subjective characteristics and concerns of the local and nonlocal affected populations. Perceived adverse impacts can be mitigated to some extent by public education, although this approach can also exacerbate public distrust. A recent permit proceeding demonstrated that public opposition can be minimized by accepting, rather than attempting to refute, community concerns and working to negotiate reasonable impact mitigation strategies (Loeb and Elliott 1993). It has also been shown that applicants who develop preventive impact reduction plans, particularly plans incorporated in the design, site, or operations of a facility, tend to be more successful in averting permitting delays than those who wait until concerns emerge, usually in the public comment period, to respond to controversies.

5 A TOOL FOR EVALUATING THE ECONOMIC COMPETITIVENESS OF COAL TECHNOLOGIES

Prepared by K.A. Guziel

The development of planning tools for electric utility analysis has been prolific in the last decade. Utilities depend on in-house and commercial software to simulate the operation of their units under a variety of scenario assumptions. At a minimum, utility models must forecast future energy demands, along with the operation of the units, which are subject to a multitude of operating constraints.

Utility system operation often has conflicting objectives (e.g., to minimize costs and maximize reliability). In recent years, additional issues, such as demand-side management and environmental concerns, have added to the complexity of the modeling systems. A term often used to describe all aspects of utility planning is integrated resource planning (IRP). The tools of IRP cover all aspects of utility planning, from demand forecast to capacity expansion, system dispatch, and emissions calculations. There are many IRP tools available, from simplified "back-of-the-envelope" calculations to sophisticated computer programs. Each tool has specific data requirements. These data requirements may require hours or months of effort to collect, enter, and analyze.

To assist the State of Hawaii Energy Planning and Policy Group within the Department of Business, Economic Development & Tourism (DBEDT) in evaluating the economic competitiveness of new/replacement coal-fired generating units, Argonne National Laboratory (ANL) has developed a simplified screening technique that allows an analyst to compare the economic and operating parameters of competing technology choices on an economic basis. This screening program provides the capability to assess the economic impact of environmental externalities when evaluating new technologies.

5.1 PURPOSE OF THE ARGONNE TECHNOLOGY EVALUATION MODEL

The Argonne Technology Evaluation Model (ATEM) is a tool that quantifies and compares the economics of up to six technologies selected as potential new power generating candidates.^{1,2} The ATEM is a Lotus 1-2-3 spreadsheet. The spreadsheet contains a set of

¹ To obtain a copy of ATEM, contact K.A. Guziel, Decision and Information Sciences Division, Argonne National Laboratory, 9700 South Cass Avenue, DIS/900, Argonne, Illinois 60439-4832.

² The ATEM was developed to examine cost/performance trade-offs in technology choice for new or replacement capacity. The impact of new technology on existing unit operations (cost, performance, and emissions) required a more complex simulation model (e.g., Argonne Utility Simulation [ARGUS] model or the Wein Automated Software Package [WASP]). Applications of such models for assessment technology choice were beyond the scope of this study.

Baseline Analysis

1993

FIGURE 5.1 Sample Screening Curve Result from ATEM

reference technologies for the state of Hawaii, along with equations to perform the economic analysis.

The analysis spreadsheet constructs cost curves for each of the selected technologies, based on information retrieved from the reference units. The analysis spreadsheet can be used to generate cost curves for current and future years. Multiyear analysis is used to display how the economic competitiveness of the units changes as the result of escalation. A sample screening curve result is displayed in Figure 5.1. The economic competitiveness of units at various capacity factor levels is determined by the intersection points of the cost curves. Figure 5.1 shows that in the year 1993, an oil combustion turbine unit (OILCT) would be the most economic unit to operate in the capacity factor range up to 44.5%. If the new unit was required to run at a higher capacity factor, then the oil steam unit (OILST) would be preferred for operation at capacity factor levels of 44.5% to 67%. The atmospheric fluidized-bed combustion (AFBC) unit is preferred for load factors greater than 67%. The pulverized coal (PC) unit is not economic at any capacity factor level.

In addition to the current year's costs, the spreadsheet generates a levelized cost curve for each selected technology. Once the data have been assembled, a sensitivity analysis can be prepared in a short time. The spreadsheets can be readily imported into Excel.

5.2 DATA REQUIREMENTS AND SOURCES

5.2.1 Data Requirements

The input data required by the spreadsheet are minimal because a reference database containing technology-specific data has been created. The principal source of data for the reference database was Black & Veatch, Inc. (1992a). The Black & Veatch data include unit size, capital cost, fixed operating and maintenance (O&M) cost, variable O&M cost, fuel cost, unit lifetime, and heat rate. Table 5.1 provides a description of the input data, and Appendix D lists the actual data values in the reference database. Any or all of these parameters can be adjusted as part of a sensitivity analysis.

The primary data requirements supplied by the user are the current year, discount rate, and cost escalation factors. The user may specify separate escalation rates for each of the main cost parameters by technology. A default value of 5% discount rate is assigned to all technologies. Typical fuel costs have been defined for each fuel type.

5.2.2 Data Sources

The cost and operating data were assembled from information provided by Black & Veatch, Inc. (1992a). In cases where costs for multiple unit stations were reported, the cost for the first unit was selected for the reference database. Additional data fields were required to calculate the emission rate of the primary pollutants. The emission rates in the Black & Veatch report (pounds/ 10^6 Btu and pounds/kilowatt-hour) could not be used directly. These rates would not allow the user to examine the impact of changing coal characteristics. Therefore, emission calculations by pollutant were developed for each technology. These emission rates did not always match with the Black & Veatch values. Some of the Black & Veatch emission rates were not sensitive to the variation in unit heat rate; for example, the emission rate for sulfur dioxide (SO₂) at full load was the same for all of the AFBC units and PC units. The emission rate calculations in ATEM provide a consistent estimation across all technology types.

The reference database, along with the economic calculations, is stored in a file called BASELINE.WK1. The reference data values should only be changed with great care. Adding new technologies requires changes to the reference data area, as well as the analysis spreadsheet.

TABLE 5.1 ATEM Input Data Fields

Field Name	Units	Remarks	Source (A or B) ^a
Technology name	-	Brief name of technology	B
Unit capacity	MWe	Net dependable capacity	B
Fuel source	-	Region/country of origin	A
Capital cost	\$/kW	-	B
Capital escalation rate	%/yr	Default = 0	A
Discount rate	%/yr	Default = 5%	A
Fixed O&M cost	\$/kW-yr	-	B
Variable O&M cost	mil/kWh	-	B
O&M escalation rate	%/yr	Applied to both fixed and variable costs; default = 0	A
Fuel cost	\$/10 ⁶ Btu	-	A
Fuel escalation rate	%/yr	Default = 0	A
Unit lifetime	yr	-	B
Heat rate	Btu/kWh	-	B
Sulfur content	%	-	B
Ash content	%	-	A
Fly ash fraction	%	-	B
Fuel heating value	Btu/lb	-	A
Sulfur removal efficiency	%	-	A
TSP removal efficiency	%	-	A
NO _x removal efficiency	%	-	A

^a A, Data provided by ANL; and B, data from Black & Veatch, Inc. (1992a).

5.3 USING THE SPREADSHEET

5.3.1 Spreadsheet Start-Up

The analysis spreadsheet can be called up directly from Lotus 1-2-3 or Excel. Retrieve the analysis spreadsheet called ATEM.WK1. Data entering and printing require the user to have a basic working knowledge of Lotus or Excel.

The ATEM contains several macros that assist the user in retrieving and graphing the data. Macros are activated by pressing the ALT key and a single letter simultaneously (ALT+letter). To clear the technology selection area, press ALT+C. This will clear the technology selection spreadsheet area (B4.G12). To erase the technology-specific cost and characteristic data (B27.G56), press ALT+E.

After retrieving the ATEM spreadsheet, specify a title in cell C1. This title will be used in the graph title field. The base year of 1993 was selected to correspond with the data provided by Black & Veatch. After entering the title, move the cursor to cell E2 to enter the current year. The current year should be greater than or equal to the base year. The ATEM

uses the base year, current year, and escalation rates to determine the current year's costs. If no escalation is specified, the current year's results will be the same as the base year.

After specifying the title and current year, the user should identify which technologies to compare. The user can select from 22 technology options defined in the reference data. Table 5.2 lists the technologies and their corresponding spreadsheet abbreviations. To select a technology, move the cursor to the row under the OPTION 1 column corresponding to the technology desired. To select a technology, enter an X (upper or lower case) in the appropriate cell. Continue selecting one technology per OPTION column. The OPTION columns must be filled sequentially; however, not all OPTION columns need to be filled. The same technology can be selected for more than one OPTION. The number of option columns is limited to six, because LOTUS can display at most six unique lines on a graph.

Once the desired technologies have been selected, press ALT+R to retrieve the baseline information. After retrieving the baseline data, the user can modify any of the unit-specific cost or operating parameters defined in Table 5.1. Fields that contain formulas have been protected. The protected fields are displayed in a different color or shade, depending on the personal computer hardware being used. Appendix E contains a listing of the analysis spreadsheet after retrieval of data from the reference database.

The analysis spreadsheet has several areas of interest. The area immediately following the technology selection contains the externality costs (dollars/ton). Default values are provided for each pollutant; however, it is recommended that a reference case with 0 externality costs be developed for comparison.

Following the externality values are the technology cost and operation data. Most data items can be readily changed by positioning the cursor in the desired field, typing a new data value, and pressing the enter key. Following the technology data are the emission rates. The emission rate calculations can be changed or set to 0 if externality costs are not to be considered for a selected technology. (See Section 5.3.3 for an example of this representation.) The capital recovery factor field contains a formula that cannot be changed.

All information below the emission rates is protected because of the detailed formulas. The first block of information pertains to the traditional cost of electricity. The traditional costs are defined by the capital, O&M, and fuel cost components. The traditional cost of electricity is followed by the externality costs. These values are then combined into fixed and variable components that are used to develop the plotting data for the current year's cost curves.

The levelization factors for the O&M, fuel, and externality costs follow the current year's plotting data. The last block of calculations is for the total levelized costs. These costs include the traditional and externalities costs.

TABLE 5.2 Technology Options

ATEM Technology Name	Technology Description	Unit Size (MWe)	Fuel Type
AFBC-184	Atmospheric fluidized-bed combustor	184	Coal
AFBC-92	Atmospheric fluidized-bed combustor	92	Coal
AFBC-30	Atmospheric fluidized-bed combustor	30	Coal
AFBC-15	Atmospheric fluidized-bed combustor	15	Coal
PFBC-30	Pressurized fluidized-bed combustor	30	Coal
PC-184	Conventional pulverized combustor	184	Coal
PC-92	Conventional pulverized combustor	92	Coal
PC-30	Conventional pulverized combustor	30	Coal
GCC-232	Gasification combined cycle	232	Coal
GCC-30	Gasification combined cycle	30	Coal
OILCC-223	Combined cycle	223	Low-sulfur fuel oil
OILCC-81	Combined cycle	81	Low-sulfur fuel oil
OILST-184	Steam	184	Low-sulfur fuel oil
OILST-92	Steam	92	Low-sulfur fuel oil
OILST-30	Steam	30	Low-sulfur fuel oil
OILST-15	Steam	15	Low-sulfur fuel oil
OILCT-81	Combustion turbine	81	No. 2 fuel oil
OILCT-63	Combustion turbine	63	No. 2 fuel oil
OILCT-22	Combustion turbine	22	No. 2 fuel oil
ADV.OILCT-26	Advanced combustion turbine	26	No. 2 fuel oil
DIESEL-15	Diesel	15	Diesel fuel
DIESEL-26	Diesel	26	Diesel fuel

The analysis spreadsheet automatically prepares two graphs. The first graph can be displayed by pressing ALT+G. This graph displays the cost (dollars/kilowatt-year) of selected technologies in the current year as a function of their capacity factor. The second graph is displayed by pressing ALT+L. This graph displays the levelized cost of the units over their respective lifetimes.

The analysis spreadsheet should be saved with a new name when data fields are changed. The ATEM.WK1 should not be replaced.

5.3.2 Representation of Externalities

The analysis spreadsheet presents costs in two categories, traditional and externality. The externality costs represent costs that are borne by "society." The externality cost imposed upon society may be reflected in areas such as higher health costs, reduced farming yield, or increased external building maintenance.³ The externalities costs are a function of the amount of pollutants released when fossil fuels are burned. The externality cost in the analysis spreadsheet is specified by the analyst and may vary by pollutant but not by technology (i.e., a ton of SO₂ from a PC plant is as detrimental as a ton of SO₂ from an oil steam plant). The pollutant emission rate is based on the technology and fuel characteristics.

Determining the externality cost per pollutant should be done on a regional basis, which was beyond the scope of this study. Based on ANL analysis for several Asian countries (Szpunar and Gillette 1992), a set of default externality costs have been provided in the analysis spreadsheet. Table 5.3 lists the default externality values.

In addition to the conventional pollutant categories, additional externality cost categories have been defined in the analysis spreadsheet. The additional fields in the externality region allow the user to represent other externality costs in terms of fixed O&M (dollars/kilowatt-year) and variable O&M (cents/kilowatt-hour). These categories can also be used to evaluate other economic impacts; for example, a carbon tax could be converted into a variable component that could be escalated independent of the traditional costs. It is recommended that initial analysis begin with all externality costs at 0 to establish baseline cost results that can be compared with a sensitivity analysis.

³ Externality benefits might also arise from the use of coal in Hawaii (for example, the economic and security [risk] benefits arising from fuel diversity and the potential reductions in the cost of electricity). The analysis of such benefits is beyond the scope of this study, since such analysis requires consideration of the costs/benefits of all competing fuel forms.

**TABLE 5.3 Default
Externality Costs**

Pollutant	Default Externality Cost (\$/ton)
SO ₂	60
NO _x	70
CO ₂	2
CO	0
TSPs	100
Volatile organic compounds	600
Methane	220

5.3.3 Sample Analysis

The primary results from the ATEM are the screening curve and levelized cost curve for the selected technology options. The screening curve combines the traditional costs (i.e., capital, O&M, and fuel) and externality costs for a selected year.

Figure 5.2 shows the change in system economics for the technologies depicted in Figure 5.1. Figure 5.2 assumes oil prices escalate at 3%/yr through the year 2003. In 2003, the OILCT unit is the most economic to operate at capacity factor levels less than 40%, while the coal AFBC unit is preferred at capacity factor levels greater than 40%. The OILST unit is not economic at any capacity factor level in 2003.

This screening curve representation provides an insight into the change in economic competitiveness of the units during the study period; for example, the oil steam unit was competitive in the near term (see Figure 5.1); however, if high fuel escalation rates are realized, the unit may not be competitive in the future, as displayed in Figure 5.2. This is important for the planner to know because the uncertainty band around fuel cost escalation assumptions increases over time.

Figure 5.3 shows the levelized cost for the same system. The levelized cost curve indicates that only the OILCT and coal AFBC units are preferred. This curve does not show that, in the near term, the OILST unit would be economic at a capacity factor level of 44-67%, as seen in Figure 5.1.

Baseline Analysis

2003

FIGURE 5.2 Screening Curve Example for 2003 with Fuel Cost Escalation

Levelized cost comparisons can be misleading if the cost analysis is not done over a range of potential capacity factors. The capacity factor used to calculate a levelized cost may not be achievable. This is especially true for large-baseload units that often depend on the cost savings associated with a cheap fuel, like coal, to offset the large capital investment; for example, a new coal-fired unit with a 65% capacity factor may be economic compared to an oil-fired unit; however, if the coal-fired unit only operates at a 50% capacity factor level due to operating constraints in the system, the coal unit might not have been the most economic choice.

Likewise, a combustion turbine may appear to be economic at capacity factor levels up to 45%; however, if the unit is not designed to operate at that level, the maintenance costs will be higher than planned, and the unit will have a shorter lifetime. If these factors had been incorporated into the analysis, a different technology might have been selected.

FIGURE 5.3 Levelized Cost of Electricity

To analyze the impact of increased levels of pollution control in conjunction with the externalities cost, select a technology (e.g., AFBC) after specifying the study title and current year. In the analysis spreadsheet, select the AFBC unit for OPTIONS 1-3. After retrieving the data, set all of the emission factors to 0 under the OPTION 1. This will represent the standard technology without externality costs. OPTION 2 represents the unit with externality costs. Option 3 represents a unit with increased capital cost, increased fixed O&M costs, and lower variable O&M costs, which correspond to a higher level of sulfur control. This example assumes no escalation and an externality cost of \$200/ton for SO₂. See Appendix E for a listing of the spreadsheet with these assumptions.

The sample spreadsheet in Appendix E contains three AFBC units. The unit under Option 1 (CONV) is based on the default values without externalities. The unit under Option 2 (CONV W/EXT) is the default AFBC unit with externality costs. The unit under Option 3 (ADV W/EXT) is based on the default AFBC unit with the previous cost and operating changes, plus the externality costs. As expected, the traditional fixed costs for the CONV and CONV W/EXT units of \$255.20/kW-yr are less than the ADV W/EXT unit cost of \$280.72/kW-yr; however, the traditional variable costs for the ADV W/EXT unit of

2.40 cents/kWh are less than the CONV and CONV W/EXT units' costs of 2.43 and 2.45 cents/kWh, respectively. The SO₂ externality cost adds an additional 0.02 cents/kWh to the variable cost of the CONV W/EXT unit. The decrease in SO₂ emissions due to the additional control results in a negligible increase in cost for the ADV W/EXT unit, as seen by the decrease in the SO₂ emission rate from 1.52×10^{-3} lb/kWh to 1.52×10^{-4} lb/kWh. The current year's plotting data show the CONV unit is preferred at all levels of capacity factor. Even when the SO₂ externality cost was increased to \$1,000/ton, the ADV W/EXT unit was more expensive on an economic basis.

5.4 LIMITATIONS TO THE ATEM SPREADSHEET

There are limitations to the representations presented in the analysis spreadsheet. This tool can provide a "quick-and-dirty" comparison of competing technologies; however, it does not consider important issues such as system load characteristics, existing system capacity, and reliability; for example, the electric generating units on Oahu must be able to follow the large daily change in load. Such issues can only be examined in a more complete capacity planning/production cost model.

The spreadsheet does not indicate the potential load-following capability of technologies. Conventional coal-fired units have limited load-following capability, which means that they typically cannot be used for cycling capacity. To operate the unit in a load-following mode typically reduces the efficiency of the unit. Likewise, running a unit at a capacity factor higher than that for which it was designed will increase maintenance costs and could reduce the lifetime of the unit. Both cost curves do not take into account the maximum availability of the unit, although this could be readily determined for each technology.

The existing system may contain old or critically located units that must operate regardless of the availability of more "economic" units. This situation is likely to be encountered on the island of Oahu, which has many old units. These "must-run" units would interfere with the economic dispatch of large-baseload units. This may limit the capacity factor of the most economic unit, which may have changed the technology of choice.

System reliability and stability are not represented in the screening curve analysis. Conventional guidelines suggest a system not build a unit whose installed capacity is greater than 10% of the system's peak load. This is especially true for isolated systems that have no emergency intertie capability; however, some isolated systems have been successful with a single unit whose capacity was greater than 10% of the system's peak load. These systems observed increased operating costs in order to maintain the reliability of the system.

Finally, the externality values included represent only the environmental costs associated with each technology (on a stand-alone basis) and not the economic/environmental benefits that might arise from the adoption of a coal-based technology in a systemwide assessment. For example, a clean coal technology (CCT) might produce residual emissions, but these emissions will likely be considerably lower than the oil plant that the CCT plant

is replacing. Furthermore, the coal plant may produce economic benefits — in terms of employment and reduced risk of future price increases — that cannot be captured in the spreadsheet. A more sophisticated capacity expansion planning tool is required to consider such issues.

6 INTEGRATION AND CROSSCUTTING ISSUES

This report has examined a variety of issues regarding the potential for increased use of coal to meet Hawaii's current and future electric energy needs. Section 2 and Appendix A provided detailed information on various coal-fired technologies that could be applicable in Hawaii, including a description of each technology; the status of its commercial availability; and data on specific characteristics such as costs, emissions rates, and solid-waste generation rates. Section 3 examined issues related to the management of the solid wastes that are produced by coal-fired generating units. Major themes of that discussion included the considerable uncertainty about how such wastes may be classified in the future (i.e., hazardous versus nonhazardous versus special waste) and the various alternatives to disposal for much of the wastes that are generated. Section 4 addressed a number of issues related to the siting of coal-fired generating units, including resource requirements, issues related to the transport of coal to and wastes away from the site of the generating unit, public perceptions of such facilities, and regulatory and legal constraints on the siting process. Section 5 described the use of a spreadsheet model (ATEM) developed by Argonne that can be used to compare the cost-effectiveness (considering both internal [traditional] and external costs) of different generating technologies, including both coal-fired and oil-fired units.

The purpose of this section is twofold. First, to facilitate the interpretation of the large amount of information that has been presented here, a framework is developed that focuses on key variables. Information on the six technologies examined in Section 2, including considerations related to waste management and the siting of coal-fired generating units, is summarized with respect to these variables. The integration of information on these variables is intended to facilitate an assessment of the appropriateness of coal technologies in Hawaii's future. Second, a number of "crosscutting" issues are identified and considered. By and large, these issues involve questions that are unresolved but may have a significant impact on the appropriateness of coal-fired technologies being considered in the Hawaiian strategic energy plan.

6.1 INTEGRATION

The extent to which coal-fired generating capacity can be used to meet Hawaii's current and future electricity demands depends upon a number of factors. One of the primary constraints is the relatively small capacities that characterize existing (and future) generating units; except on the island of Oahu, capacities range from 1 to 25 MW. These small unit sizes reflect the dispersed nature of the electric demand, the daily fluctuation in load experienced on the islands, and the corresponding need for a considerable amount of intermediate and peaking capacity. Because most coal-fired generating technologies are generally designed to serve baseload and intermediate load, they may be less appropriate to the load patterns experienced on the Hawaiian islands. Nonetheless, particular coal technologies might be appropriate in certain circumstances. The specific issues used to screen the technologies include (1) capacity constraints/applicable market, (2) commercial

availability, (3) costs (both internal and external), (4) waste generation characteristics (including both air emissions and solid wastes), and (5) siting issues. Summary information on each of these characteristics is presented in Table 6.1 by technology.

6.1.1 Capacity Constraints/Applicable Market

Based on the material presented in Section 2 and Appendix A, further deployment of coal-fired generating capacity in Hawaii is technologically feasible at this time. Technologies that appear to be most applicable to the situation in Hawaii include coal-water mixtures (CWMs), slagging combustors, and atmospheric fluidized-bed combustion (AFBC); however, each of these technologies entails some limitations. Coal-water mixtures pose a problem to the extent that there are economies of scale associated with the preparation and transport of the fuel. Hence, unless a sufficient amount of capacity is retrofitted for CWM, fuel (and fuel handling) costs may negate the cost-effectiveness of this option. Slagging combustors require additional coal preparation equipment, since the coal must first be crushed or pulverized. This requirement will increase the relative cost of this option and entail additional land-use requirements. In the case of AFBC, the majority of experience to date suggests that this technology is most appropriate for meeting baseload needs. This characteristic could limit its deployment in Hawaii, since load varies considerably on a daily basis, creating the need for a significant amount of intermediate and peaking capacity; however, operation of the AES Barbers Point Plant appears to successfully follow the demand profile, indicating that AFBC technology can satisfy the load-following requirements of Hawaii. In spite of the previous limitations, these technologies (CWM, slagging combustion, and AFBC) appear to be reasonably well suited to Hawaii's needs in terms of generating capacities.

The other technologies (IGCC; PFBC) considered in Section 2 and Appendix A — while potentially applicable — appear to hold less promise at the present time, primarily due to scale. Small IGCC units have been tested; however, economics dictate sizes that are larger (100 MW and above) than would be optimal in Hawaii. The same condition applies to PFBC. According to currently available information, economic applications of PFBC may be limited to units with capacities of 50 MW or larger. Pulverized-coal units, while certainly technically feasible at relatively small sizes, do not scale down very well. Equipment to pulverize and handle coal, combined with the additional costs that would be incurred to reduce air pollutant emissions to BACT levels, would be significant constraints on the applicability of this technology in Hawaii.

6.1.2 Commercial Availability

In addition to meeting the capacity constraints in Hawaii, CWM, slagging combustor, and AFBC technologies are all commercially available. As noted in Appendix A, Section A.2.2, while CWM is commercially available, it is still in its infancy regarding market adoption. In addition, the precise formulation of a CWM will vary by supplier. As such, additional site-specific testing is required.

TABLE 6.1 Comparison/Integration of Candidate Coal-Fired Technologies

Technology	Capacity Constraints/Applicable Market	Commercial Availability	Estimated Costs
Pulverized coal	Units range from less than 50 MW to more than 800 MW.	Commercially available, as are a number of add-on emissions control devices that can reduce emissions rates below current standards.	Black & Veatch capital costs range between \$2,329/kW (184-MW plant) and \$3,931/kW (30-MW plant); fixed O&M: \$60-221/kW-yr; variable O&M: 2.7-3.5 mills/kWh.
Coal-water mixtures	Can be used in oil-burning units once certain unit modifications and additions are completed; however, there are significant economies of scale in fuel preparation, suggesting multiple small units would be required to justify fuel preparation costs.	Commercially available, but limited; additional testing is considered desirable.	Incremental electricity estimates of 11-23 mills/kWh compared to PC units; externality costs (per 10 ⁶ Btu) of air emissions comparable to or less than those for PC units.
Slagging combustors	Can be used to retrofit existing oil-fired boilers; 1-20-MW units have been thoroughly tested; approximately 1,000 MW of capacity in Hawaii may be considered for retrofit with slagging combustors.	Commercially available since 1988; slagging combustors can burn pulverized coal and may be able to use CWMs in the near future.	Estimates may be less than those for repowering with AFBC or PFBC.
Atmospheric fluidized-bed combustion	Unit sizes in commercial applications can be as small as 10 MW; larger units (100-150 MW) have also been installed.	Commercially available and in use at the AES Barbers Point facility; a number of different designs have undergone thorough testing.	Capital and O&M estimates appear comparable to PC units.
Integrated gasification combined cycle	Units as small as 55 MW are planned; however, the optimal unit capacity appears to lie in the 100-200-MW range.	Demonstration projects have been completed, and others are underway. Several commercial-scale facilities are being planned, under construction, or currently in shakedown. All are larger than suitable for Hawaii.	Relatively high variable O&M estimates compared to PC units; incremental electricity cost of 1-2 mills/kWh compared to PC units; however, externality costs are relatively low given low emission rates.
Pressurized fluidized-bed combustion	Tests have involved units ranging from 15 MW to 330 MW; however, economic applications may be limited to 80 MW or larger (projected optimal size is > 300 MW).	PFBC demonstration projects underway; commercial units are expected to begin operation in the 1995-2000 time frame.	Capital cost estimates comparable to PC units; fixed and variable O&M costs and externality costs of air emissions appear lower than for PC units.

TABLE 6.1 (Cont.)

Technology	Air Emissions	Solid Wastes	Siting Issues
Pulverized coal	Meets NAAQSs and NSPSs with the use of add-on technologies; advanced technologies can yield additional reductions in certain emissions.	Approximately 144 t/d of fly ash and bottom ash from a 90-MW unit.	Potential to encounter opposition due to land use requirements, reputation (i.e., not a "clean-coal" technology), and transport mode issues.
Coal-water mixtures	Comparable to PC units; SO ₂ and NO _x emissions may be lower.	Quantity of waste produced is projected to be less than for PC units due to lower ash content of coal.	Can be retrofitted to existing units; however, facility must be developed to produce the coal-water mixture.
Slagging combustors	Comparable to PC units; NO _x emission rate is a function of staged combustion; SO ₂ emission is a function of sorbent-to-sulfur ratio.	Most (80%) of the fly ash is composed of mineral matter.	Technically feasible for retrofit on existing units. Engineering analysis is required to determine retrofitability.
Atmospheric fluidized-bed combustion	Lower NO _x emission rates than PC units; SO ₂ and particulate emissions comparable to PC units; however, some particulate emissions may be hazardous.	Results in nonhazardous waste (≈148 t/d for a 90-MW unit) with multiple potential uses (e.g., construction aggregate).	In the case of Hawaii, AFBC would require construction of new units; thus the full range of siting issues is relevant.
Integrated gasification combined cycle	Extremely low emission rates.	Dry, benign solid waste (80-180 lb/MWh); slag can be used in construction, and recovered sulfur can be used in chemical/fertilizer industry.	Can be used to repower existing units; for new plants, requires 15% less land area than a comparable PC plant.
Pressurized fluidized bed combustion	Lower emission rates than PC units.	Twice as much solid waste as a PC unit; however, waste is benign and can be used in road or building construction.	Can be used to repower existing units, however, potential visibility impacts due to height of pressure vessel (100 ft).

Alternatively, slagging combustors have been marketed commercially since 1988. In addition, it is expected that slagging combustors will be able to use CWMs in the near future. This could increase the demand for CWMs and would address the fuel cost issue raised in Section 6.1.1. To be specific, retrofitting some oil-fired units to burn CWMs and retrofitting other units with slagging combustors could complement one another, resulting in a decrease in the average cost of production for each of these two technologies. The commercial availability of AFBC is enhanced by its performance with respect to air emissions and its ability to utilize coals of varying quality.

Both IGCC and PFBC units are expected to become commercially available within the next 5-10 years, depending on "market-pull" factors; however, the lack of a match between Hawaii's relatively small capacity requirements and the minimum technology generating capacities determined to be economically viable precludes these technologies from consideration at this time (the exception to this finding might be on the island of Oahu, where larger capacity requirements are projected). In a similar manner, the fact that PC technology is commercially available is overshadowed by capacity constraints and waste-related issues.

6.1.3 Costs

A wide array of costs — prepared by numerous researchers — has been developed for coal-fired generating units. Traditional costs include capital, O&M expenditures, and fuel costs. Costs not typically considered to date include those attributable to externalities (i.e., air emissions, disruption of current land-use patterns, and adverse impacts associated with the transport of coal to and wastes away from generating units). A full accounting of all costs would be necessary to accurately assess the true cost-effectiveness of each technology; however, due to data limitations, estimation of certain site-specific costs is not currently possible. Consequently, cost estimates are limited to the traditional costs of constructing and operating each technology and only some of the external costs related to specific air emissions.

In this study, the capital, operating, and fuel cost data for coal-fired technologies were largely extracted from the Black & Veatch, Inc. (1993) report prepared for Hawaiian Electric Co., Inc. (HECO). These estimates were used due to their site-specificity to Hawaii and because project constraints precluded use of (or comparison with) other estimates. Three alternative PC configurations were compared with the costs of alternative coal-fired generating technologies: one 184-MW PC unit, one 92-MW PC unit, and one 30-MW unit. By and large, the costs of alternative technologies compared favorably with those of the 180-MW PC unit. The CWMs would result in incremental electricity costs of 11-23 mills/kWh, compared to PC units; however, this increase is offset at least partially by lower externality costs, in particular for SO₂ and NO_x. In addition, CWMs would produce less solid waste per ton of coal than a PC unit, resulting in lower external waste management costs. Atmospheric fluidized-bed combustion units are expected to result in capital and O&M costs similar to those for a PC unit of comparable size.

The PFBC and IGCC units also are expected to result in capital costs of a similar magnitude; however, O&M costs are projected to be lower for PFBC units, although somewhat higher for IGCC units. The external costs of air emissions from AFBC, PFBC, and IGCC units would all be lower than the same costs for PC units. Cost data on slagging combustors are relatively limited; however, the costs of repowering with slagging combustors is projected to be less than the cost of repowering with PCFB or IGCC. External costs of air emissions for slagging combustors are also lower than the same costs for PC units.

Although many of the alternatives to PC result in reduced air emissions, it is important to recognize a trade-off in the form of increased production of solid wastes. While data on the waste generation rates for the CCTs considered here are not readily available, it has been estimated that technologies such as PFBC may result in twice as much solid waste as a comparably sized PC unit. Solid waste generation rates for other CCTs are also expected to be higher than the rate for comparably sized PC units. Depending on how such wastes are classified (e.g., hazardous versus nonhazardous) and managed (e.g., disposed of versus recycled), the resulting internal and external costs could offset some of the cost advantages attributable to reduced air emissions.

An additional note on costs concerns the relatively small generating capacities currently in use in Hawaii. In general, the cost-effectiveness of coal-fired technologies is positively related to the generating capacity of the installed units. Consequently, in an effort to minimize production costs, it appears reasonable to consider replacement of several smaller existing units with one coal-fired unit; however, if a larger coal-fired unit is used to replace multiple smaller oil-fired units, system reliability may become a concern. This potential decrease in reliability must be weighed against, among other things, the benefits that come from reduced dependence on foreign oil for meeting Hawaii's electrical needs, and a more diversified portfolio of energy supplies.

6.1.4 Waste Generation Characteristics

Waste-related issues are grouped into two categories — air emissions and solid wastes. Considering air emissions first, all of the technologies evaluated here are capable of meeting both federal and state emissions standards, either directly or through the application of specific add-on technologies. For a given technology, the determinants of the amount of emissions per kilowatt-hour include the heat rate of the generating unit, the characteristics of the fuel (e.g., sulfur content), and any pretreatment of the coal. While the quantities of air emissions vary across technologies and are fuel dependent, it is generally the case that all five alternatives to PC technology result in reduced emission rates for one or more of the major pollutants considered here (SO_2 , NO_x , CO, CO_2 , VOCs, and TSPs).¹ (According to estimates produced by Black & Veatch, Inc. [1992b], CO_2 emissions rates would

¹ While CO_2 emission rates vary by heat rate, it is unclear how the heat rates of AFBC, PFBC, and IGCC could be higher than that for a comparable PC unit. All other references to the current generation of those advanced technologies indicate efficiencies that are 1 to 5 percentage points higher than for a PC/FGD unit.

be higher for AFBC and IGCC units than for PC units.) In contrast, the data used in the ATEM spreadsheet indicate that IGCC would produce lower CO₂ emissions rates than PC units. The actual amount of such emissions is dependent on the heat rate of the unit and, as such, may vary. Overall, AFBC, IGCC, and PFBC compare most favorably on the basis of air emissions. Slagging combustors also offer a clear advantage over PC units in this regard.

As was noted in Sections 3.1.1.1 and 6.1.3, solid wastes are a different matter. First, alternatives to PC units (i.e., CCTs) generally produce larger quantities of solid wastes, which in some cases may be recycled (reused). In addition, the composition of such wastes is more varied, and it is less clear how such wastes will ultimately be classified (i.e., hazardous versus nonhazardous) by the EPA. The impact of these uncertainties is discussed in more detail in Section 6.2.1.1.

6.1.5 Siting Issues

As was discussed in Section 4, the extent to which siting is an issue in the decision of whether to develop additional coal-fired generating capacity in Hawaii will depend upon a variety of factors, including land-use and water requirements, the mode(s) used to transport coal and wastes, and the public's perception of such facilities. In addition, much will depend on how the proponents of such a facility approach the siting process. One important distinction among the technologies considered is the fact that CWMs, slagging combustors, and IGCC and PFBC units can all be used to repower existing oil-fired units. Consequently, to the extent that these technologies are used in this manner, they should encounter less public opposition than PC or AFBC units in greenfield applications. In addition, small-capacity units (e.g., slagging combustors retrofitted to small [1-20-MW] oil-fired units) with correspondingly small fuel needs can be expected to impose less external costs on the surrounding environment than large-capacity units. This should also serve to blunt, to some extent, public opposition to the use of coal. Nonetheless, issues associated with the transport of coal and wastes, as well as the public's possible adverse reaction to coal-fired generation in general, may present difficulties in the siting process.

6.2 CROSSCUTTING ISSUES

Although there is a considerable amount of available information on the different coal-fired technologies that might be used in Hawaii, there are also a number of unresolved issues. Chief among these are a number of uncertainties with respect to waste-related issues and costs (both internal and external) and siting. Also left unresolved is the question of how coal compares to other energy sources (such as biomass, geothermal, wind, and solar) that could be developed in Hawaii. While this latter issue was not intended to be addressed in this report, it is nonetheless appropriate to consider, in a cursory fashion, its implications for the viability of coal as a major energy source in the state.

6.2.1 Uncertainties

6.2.1.1 Waste Management

One of the major questions left unanswered in this report is the amount of waste that would be generated by the different CCTs. Also unresolved is the question of how at least some part of the solid wastes resulting from both conventional technologies and CCTs will ultimately be classified (i.e., hazardous versus nonhazardous). The answers to these questions will have important implications for the siting of certain coal-fired technologies, as well as the relative cost-effectiveness of these strategies. With respect to the quantities of wastes, disposal capacity on the islands is limited. Thus, there is a strong incentive to find alternative uses for such wastes. In fact, a number of alternative uses for components of the solid waste stream from coal-fired generating units currently exist and are utilized to varying degrees (Section 3.4); however, it is important to recognize the limitations of this option in the case of Hawaii. Combustion of coal to produce a significant amount of electricity would yield large amounts of waste on a continuous basis. It is unlikely that uses in the state would be of a magnitude sufficient to utilize all of the wastes that are generated. Thus, some amount of disposal or shipment off-island would be necessary. As was discussed in Section 3.3, the costs of off-island disposal would be substantial, especially if such wastes are considered hazardous.

With respect to the classification of coal combustion solid wastes, a determination that certain wastes generated by combusting coal to produce electricity should be classified as hazardous is almost certain to increase the public's opposition to siting such facilities. This follows from the additional problems that would be posed with respect to management of the resulting wastes. Although it is likely that such wastes would ultimately be managed away from Hawaii, there is still the problem of transporting the wastes to a port facility and then by ship to their final destination. In addition, as was discussed in Section 3, management of such wastes in the western United States, as is currently being done, may meet with additional resistance in light of the current agreement between Hawaii and those states regarding management of Hawaii's hazardous wastes. The cost of managing hazardous wastes is also much greater than the costs associated with a comparable amount of nonhazardous wastes.

On a related note, the Clean Air Act Amendments of 1990 are likely to further constrain the cost-effectiveness of coal-fired generating technologies as more stringent limits are imposed on air emissions — in the near term, SO_2 and NO_x ; and in the future, air toxics and, potentially, greenhouse gases (GHGs).

6.2.1.2 Costs

Production Costs. The data on production costs (i.e., capital and fixed and variable costs) reported in Section 2 are generally for units with capacities greater than those of units

existing in Hawaii. The smaller generating capacity of most units in Hawaii reflects the trade-off between capacity, load served, and reliability. Even as load continues to grow throughout the islands, this relationship is likely to encourage the development of small- rather than large-capacity generating units. Because most generating technologies exhibit economies of scale, smaller units will tend to be less cost-effective than the units described in Section 2.

Emissions Control. As a result of the extensive amount of effort that has gone into the development of various add-on technologies for controlling emissions from PC units, cost estimates for these add-on technologies are readily available. In contrast, data on the costs of the incremental control (i.e., control beyond that inherent in the technology in question) of emissions from alternative CCTs are relatively limited. In addition, most estimates that do exist are for larger, as opposed to smaller, capacity units. Thus, it is difficult to estimate the incremental costs of reductions in emissions beyond those attributable to the technology configuration in question; however, it can be assumed that costs are not linearly related to the size of the unit. Instead, there are considerable economies of scale associated with add-on control technologies. Thus, for example, a 50% reduction in the generating capacity of a particular CCT would cause the incremental costs of the add-on emissions controls to fall by something less than 50%. In fact, the marginal cost of controlling emissions from CCTs to levels that go beyond those achieved by the controls inherent in the production process are extremely high.

6.2.2 Siting Issues

Another unresolved issue associated with the increased use of coal in Hawaii concerns the potential locations of coal-fired generating facilities. In situations in which construction of a new generating unit (as opposed to retrofitting or repowering an existing unit) is contemplated, the cost of diverting current land uses to accommodate the proposed facility is likely to vary across sites. In addition, as the distance between the proposed site for such a facility and the port where the coal is delivered to the island increases, so will the costs, both private and external, of delivering the coal to the facility. Depending on the transport mode that is selected, the public's response may be more or less positive. Thus, a technology that appears to be cost-effective in the absence of such considerations may be a less than optimal choice once such costs are factored in.

6.2.3 Trade-Offs among Alternative Energy Sources

A comparison of the PC units characterized and costed by Black & Veatch, Inc. (1992b) and oil-fired units with similar capacities revealed that the PC units are more costly to install and operate. Because the internal costs of PC units tend to be equal or less than the costs of the other coal-fired technologies considered here, this conclusion would apply to these other technologies as well; however, it is important to recognize that the higher internal costs of coal-fired technologies are offset to some extent by the lower emissions rates

associated with certain coal-fired technologies. There is also the matter of the value of decreased dependence on foreign oil for production of electricity in the Hawaiian islands, as well as the value of a more diversified portfolio of energy sources. These factors, along with the benefits and costs of other sources of electrical energy, also need to be considered before conclusions can be reached regarding the extent to which further development of coal as an energy source in Hawaii is warranted.

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APPENDIX A:

**COAL-FIRED GENERATION TECHNOLOGIES: SYNOPSIS OF ISSUES
RELEVANT TO THEIR ADOPTION IN HAWAII**

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APPENDIX A:**COAL-FIRED GENERATION TECHNOLOGIES: SYNOPSIS OF ISSUES
RELEVANT TO THEIR ADOPTION IN HAWAII**

Prepared by C.B. Szpunar

This appendix provides information on key issues relevant to coal technology adoption in Hawaii: applicable market, commercialization status, plant size and modularity considerations, and technology and environmental performance. The coal technologies considered are those that have the potential to serve the current/future power generation needs on the Hawaiian islands (see Section 2). A pulverized-coal unit with flue gas desulfurization (PC/FGD) is used as a reference facility. Most of the information presented in the appendix is drawn from Szpunar and Gillette (1990), with updates and additional data included (and cited) where appropriate.

While providing relevant information on technology adoption issues, the appendix does not contain the most current data on technology vendor designs, costs, and market activities, nor does it summarize current R&D activities relative to the technologies discussed. Such information can be obtained by contacting the Clean Coal Technology Program Office, U.S. Department of Energy.

A.1 CONVENTIONAL PULVERIZED-COAL-FIRED ELECTRIC POWER PLANT

A conventional PC power plant, equipped with particulate removal devices only, is used as the base technology upon which various types of postcombustion SO₂ and NO_x control equipment can be added. The sulfur emissions from this type of plant are tied to the sulfur content of its coal feed. New emission technologies discussed subsequently can be compared with the base technology to highlight their attributes in terms of their SO₂ and NO_x removal abilities and associated costs.

The most abundant technology for existing coal-fired power plants, PC units can be constructed in sizes that range from approximately 50 MW to more than 1,200 MW in capacity. Typically, large plants are built using multiple units, so few extremely large (above 800 MW) units exist. These plants can be fired with most types of coal, from low-quality lignite to high-quality bituminous coal; however, the plant design is optimized for the expected fuel characteristics, and deviating from design fuel may have a significant impact on efficiency, reliability, and the costs of operation and maintenance. The net efficiency of the energy conversion from raw-coal feed to the export of electricity is typically on the order of 35-38%. (The net heat rate for conventional plants ranges from 9,000 to 11,000 Btu/kW.)

Pulverized-coal power plants are often operated in baseload mode (that is, at rated capacity with as few start-ups and shutdowns as possible). The plants can be operated at less than rated capacity (turndown) but at a cost to efficiency. Past data indicate that

operating at 25% of capacity can decrease operating efficiency by as much as 10 percentage points from the rated capacity efficiency of 32-35%. Due to demand considerations, PC power plants are also operated in the intermediate or cycling mode, since they are capable of it.

Most modern PC plants include particulate control devices in their design but, until the adoption of new source performance standards (NSPSs) in 1978, were constructed without FGD. With the enactment of the Clean Air Act Amendments (CAAA) of 1990, most existing PC plants without SO₂ control will be required to reduce emissions to 2.5 lb/10⁶ Btu by 1995 and to 1.2 lb/10⁶ Btu by 2000 through a retrofit control action. Newer PC designs include advanced burners for control of NO_x; existing PC units will also be required to control NO_x as a result of the 1990 CAAA.

Land requirements for a PC plant depend to a great extent on the type of coal used and the presence of an FGD system. Space is needed for buildings, roads, coal piles, ash storage, FGD waste storage, and a buffer zone around the plant. The required area for a plant burning high-sulfur coal and using a conventional wet limestone FGD system can be two to three times the requirement for a plant burning low-sulfur coal.

A.1.1 Flue Gas Desulfurization

Flue gas scrubbing (or FGD) is a commercial technology that has been used in many power plants, especially those burning high-sulfur coal. The technology involves reduction of SO₂ from the combustion flue gases by chemical reaction with alkaline sorbents prior to atmospheric emission. The process does not normally affect NO_x emissions.

In conventional technology (a wet flue gas scrubber), the gas produced in coal combustion is typically sprayed with a slurry made up of water and an alkaline reagent, usually lime or limestone. The SO₂ in the flue gas reacts chemically with the reagent in the slurry to capture sulfur pollutants in the flue gas before it exits the stack, forming a wet waste product (sludge) made up of calcium sulfite (CaSO₃), calcium sulfate (CaSO₄), water, and unreacted limestone (DOE 1987a; 1993).

Scrubbers have been widely deployed, some removing more than 90% of the SO₂ emissions from high-sulfur coals. Scrubbers are relatively costly to install and operate and may consume as much as 8% of the plant's output to run pumps, fans, and a flue gas reheating system. The scrubber has high maintenance costs and consumes a large amount of water (500-2,500 gal/min for a 500-MW unit) (Szpunar and Gillette 1990).

Wet flue gas scrubbing reduces the overall efficiency of a PC power plant from a range of 35-38% to 32-35%. Furthermore, there are reliability problems due to plugging and fouling of the equipment and corrosion of fans and downstream ductwork. Large spaces are typically required to handle scrubber waste — on the order of 1 acre-ft/MW/yr (Szpunar and Gillette 1990).

An alternative approach is the dry scrubber, or spray dryer. In a dry scrubber, the reagent slurry — usually lime — is injected into an absorber vessel in a finely atomized form. The droplets evaporate in the hot gas, leaving only dry, reacted particles for collection in a conventional baghouse or electrostatic precipitator (ESP). Although the dry scrubber is simpler, its effectiveness for SO₂ removal (60-70%) is not as great as that of wet FGD.

A.1.2 Environmental Concerns

A.1.2.1 Atmospheric Emissions — Pulverized-Coal Units

Black & Veatch, Inc. (1992a) has estimated emissions emanating from a generic 180-MW PC unit projected to be located in Hawaii. These emissions are based on firing a coal with a calorific value of 12,800 Btu/lb (this value is at the high end of internationally traded coals; more typical values are between 11,000 and 12,000 Btu/lb), 1.0% sulfur, 65.1% carbon, and 12.6% ash. These estimated emissions are as follows:

- SO₂ emissions of 0.16 lb/10⁶ Btu,
- NO_x emissions of 0.30 lb/10⁶ Btu,
- Carbon dioxide (CO₂) emissions as a function of the carbon content of the fuel and the calorific value of the feed coal (i.e., based on 100% conversion) of 186 lb/10⁶ Btu,
- Carbon monoxide (CO) emissions of 0.15 lb/10⁶ Btu,
- Volatile organic compound (VOC) emissions of 0.015 lb/10⁶ Btu, and
- Particulate emissions of 0.015 lb/10⁶ Btu.

A.1.2.2 Comparative Oil-Fired Estimates

Black & Veatch, Inc. (1992a) has made similar estimates for emissions from two types of baseload oil-fired units projected to be located in Hawaii, oil combustion turbine and oil steam units, which can be compared with the aforementioned PC estimates. These estimates are based on firing a low-sulfur fuel oil (LSFO) with a calorific value of 19,065 Btu/lb, 0.5% sulfur, 0.5% nitrogen, 85.9% carbon, and 0.05% ash and are as follows:

- SO₂ emissions of 0.52 lb/10⁶ Btu in both cases;
- NO_x emissions of 0.43 and 0.75 lb/10⁶ Btu, respectively;
- CO₂ emissions as a function of the carbon content and the calorific value of the LSFO (i.e., based on 100% conversion) of 165 lb/10⁶ Btu in both cases;

- CO emissions of 0.021 and 0.015 lb/10⁶ Btu, respectively;
- VOC emissions of 0.010 and 0.015 lb/10⁶ Btu, respectively; and
- Particulate emissions of 0.026 and 0.015 lb/10⁶ Btu, respectively.

A.1.2.3 Production of Solid Waste

With respect to potential electricity generation expansion plans for Hawaii, Black & Veatch, Inc. (1992a) has suggested that fly ash and bottom ash emanating from a PC unit may be collected, pelletized, and conveyed off-site for disposal. Black & Veatch, Inc. estimates that approximately 144 t/d and 288 t/d would be generated by 90-MW and 180-MW units, respectively. A detailed treatment of solid waste issues is presented in Section 3 of this report.

A.2 COAL-WATER MIXTURES¹

Coal-water mixtures are composed of 65-75% (by weight) coal and about 1% chemical additives; the rest is water. These mixtures have been designed to substitute, in certain applications, for oil, without significant alterations to the plant or without derating the plant capacity, although lack of plant derating remains a goal.

Coal-water mixtures are discussed here as one option because most of the Hawaiian Islands' existing capacity for electricity generation is oil-fired and thus seemingly amenable to firing CWMs; however, Hawaii's unit sizes tend to be very small — Maui, less than 13 MW; Kauai, less than 25 MW; Hawaii (the Big Island), less than 25 MW; and Oahu, 50-180 MW — perhaps precluding the shift to CWMs due to the relatively small overall volume to be contracted. Moreover, significant emission control measures need to be taken. Nevertheless, CWMs may still merit serious consideration on the Hawaiian Islands and are, therefore, presented here.

Along with the DOE, the EPRI is one of the principal sponsors of CWMs in the United States. Its work on coal-oil mixtures started in 1974 and on coal-water slurries (i.e., CWMs) in 1978. The economic advantages of CWMs resulted in EPRI subsequently focusing its research efforts entirely on this alternative (EPRI 1984). Low oil prices have meant that there has been little motivation for electric utilities to advance the use of this fuel. Nevertheless, EPRI continues to fund a small amount of work on this technology (EPRI 1986a) in order to provide fuel supply insurance for future scenarios that include disruptions in oil supply.

¹ Coal-water mixtures were a major topic at the 18th International Technical Conference of Coal Utilization and Fuel Systems, held in Clearwater, Florida, on April 26-29, 1993. The proceedings from this conference present a wealth of information on this subject.

Existing oil-fired boilers require a number of changes if they are to burn CWMs. Modifications to the oil-system burner and additions to the boiler are needed. Ash removal and handling must also be addressed. If sulfur-control equipment is needed, even more expenditures may be required. In summary, changing from oil to CWM fuel is not an inexpensive or insignificant effort; however, if the coal is highly cleaned before the CWM is prepared, the need for some plant modifications may be reduced or even eliminated. Nevertheless, the capacity of the boiler typically needs to be downgraded because it is not usually capable of providing full output when fired with a CWM; however, if the oil-fired units were initially designed to have coal capability, they do not require significant derating to use CWMs (although this is not the case in Hawaii). Typical deratings are from 25% to 40%, but values as high as 60% have been estimated. Recent improvements in coal-water fuels are reducing the level of derating; for instance, one combustion modeling study indicates that the use of ultraclean coal-water fuel could reduce boiler derating to as little as 4%, although derating of 10-20% in oil-fired boilers is more likely (Fraser et al. 1993).

Transportation from the slurry-manufacturing facility to the point of use is required. In the United States, excluding long-time coal-water slurry² projects, experience has been largely with small quantities of CWM fuel for testing. Rail, truck, and barge modes of transportation have been used to deliver test fuels; pipeline transport has not yet been attempted. The EPRI conducted a study (EPRI 1987) that incorporated all four transportation modes and addressed the technical and economic issues involved. The focus was on understanding the characteristics and behavior of the particular slurries, so that equipment and operating procedures could be properly specified. Szpunar et al. (1989) investigated alternative and innovative transport modes for moving U.S. steam coal to the Pacific Basin and found that the delivered cost of CWMs could be competitive with the price of delivered fuel oil, if such an industry existed. Coal-water mixtures have been shown to be safely transportable, although special pumping and handling are required to prevent alteration of physical properties during transport.

A.2.1 Applicable Market

For electric utility applications, the primary market for CWMs is for retrofit of existing oil-fired units. Studies have generally indicated that for new units, it is cheaper to use PC directly than to use a CWM; however, in certain cases (such as where disposal of waste coal is a problem), the use of a CWM produced from waste coal can result in a lower fuel cost than the use of PC (Wan et al. 1993).

² A coal-water slurry requires dewatering at its destination, prior to combustion. Coal-water slurry projects have been in commercial use since 1957 (the Consolidation pipeline in Ohio), although only one currently exists — the Black Mesa pipeline system in Arizona. On the other hand, CWMs are a form of coal-water slurry that have a higher coal concentration and can be fired directly as a low-Btu combustible fuel upon delivery, without being dewatered prior to combustion (Szpunar et al. 1989).

The market for large industrial-sized retrofits, like Hawaii's smaller-unit power generation sizes, also has potential. Industrial concerns with large demands for steam may want to use CWMs if new oil-fired units are not an option or if coal is difficult to use because of lack of space, materials-handling problems, or coal transport problems.

Because the bulk of Hawaii's existing capacity is oil-fired, it lends itself to potential CWM application. In this way, any stigma attached to the direct use of coal could be ameliorated, although resulting ash and air emissions still need to be addressed.

A.2.2 Commercialization Status

Because of oil's easy availability and its continuing low price, the CWM supply industry is still in its infancy. Each of the potential suppliers has its own proprietary formulation for CWMs. Coal characteristics and chemical additives are the main factors that contribute to specification variations among suppliers.

Applications for CWMs can be economically justified in specific cases and may prove useful in Hawaii; however, additional boiler tests, combined with the use of advanced coal preparation techniques, and site-specific testing are desirable. Nonetheless, CWMs could be quickly supplied if a firm commitment to this fuel were made by a specific user.

A recent report cites Japan as having become the first commercial CWM supplier. A 500,000-t/yr facility is being built for mid-1993 completion. It is expected to supply 40% of the needs for a 600-MW unit at Joban's Nakoso Plant (*Coal & Synfuels Technology*, Sept. 7, 1992).

A.2.3 Plant Size and Modularity Considerations

Major supply factors to be considered include the availability of a CWM manufacturing facility large enough to provide a competitive fuel and an efficient transportation network or distribution system (or both). For development and testing of commercial fuels, a CWM plant would need to produce 30,000-100,000 tons/yr; for commercial-scale applications, a 10-fold increase in plant capacity would be required. Hawaii would require something in between the two cases.

A.2.4 Performance Issues

The thermal efficiency of a plant using a CWM is about 2% less than that of an oil-fired plant, depending on design conditions. For units smaller than about 50 MW, the heat rate may range from 11,000 to 12,000 Btu/kWh at full load.

A.2.4.1 Plant Complexity and Operability

Plants using CWMs are certainly expected to be more complex and probably will be somewhat more difficult to operate than oil-fired plants; however, with developmental experience, the increased difficulty is not expected to be a barrier to commercialization. Also, the plants should be acceptable for many industrial applications.

A.2.4.2 Partial-Load Operation

Units operating on a CWM are capable of turndown ratios of about 3:1 (IPCC 1993).

A.2.4.3 Reliability and Availability

Information that would provide a reasonable statistical basis for assessing reliability and availability is lacking; however, compared with oil-fired units of similar design, CWM-fired units would have additional factors that may tend to reduce reliability and availability somewhat. Examples are burner-tip lifetime and ash buildup on furnace surfaces. Nevertheless, design goals for CWMs are expected to keep such factors within an acceptable range.

A.2.5 Environmental Concerns

The environmental impact of CWM applications depends on the characteristics of the oil that was previously burned in the unit and the level of coal beneficiation prior to preparation of the CWM. In some instances, using low-sulfur coal in the CWM can even lower SO₂ emissions; however, ash disposal and related concerns are expected to persist.

A.2.5.1 Atmospheric Emissions

Sulfur dioxide, NO_x, and particulate emissions are expected to meet existing federal standards. Sulfur dioxide emissions depend on the sulfur content of the coal and use of appropriate SO₂ control systems. In general, with a high level of coal cleaning before production of the CWM, the amount of ash input to the boiler tends to be lower than for a conventional coal-fired plant. Cleaning of the flue gas to meet standards should therefore be less burdensome. Nitrogen oxide emissions should meet existing standards; however, because of burner design, there may be less design flexibility. Nevertheless, the high water content of the fuel is expected to keep thermally produced NO_x at low levels.

A.2.5.2 Production of Solid Waste (and By-Products)

Solid wastes resulting from SO₂ cleanup and ash collection are normally expected to be higher than for an oil-fired unit but lower than for a conventional coal-fired plant. The details of waste production depend directly on the specific fuel characteristics.

A.2.6 General Comments

The slurry fuel burning system is not unlike a PC boiler, except that the feeding operation is easier and the fuel relatively cleaner. Coal in the form of a slurry is pumped under pressure into the burner manifold, where the slurry is injected into the combustion chamber. With the proper combustor design, high combustion efficiencies can be achieved.

The preparation and use of a CWM may increase the cost of utilization; however, the advantages of CWMs (i.e., transportability, ease of handling, safety, ease of feeding into the combustor, and use of cleaner coal resulting from the fuel preparation process) may offset the effects of increased utilization costs. Use of CWMs prepared from standard PC will necessitate the same pollutant control processes as with PC systems; however, a by-product of the grinding process is removal of some of the ash and sulfur from the coal prior to combustion. Therefore, most CWMs are produced as clean fuels, thus reducing to a minimum the pollution control requirements at the user site (Szpunar and Gillette 1990).

One real concern is derating. In any oil conversion project, derating will most likely occur to compensate for slagging and plugging of heat transfer surfaces and for the reduction in gas velocity needed to provide additional time for combustion of coal particles and to reduce boiler erosion by coal ash.

Changes to plants originally designed for oil to permit use of coal slurries would include the following:

- Coal-handling equipment to off-load, reclaim, transfer, grind, mix, agitate, and pump the coal;
- Bottom-ash equipment for storage and transport;
- Control equipment to desulfurize and remove particulates from the flue gas; and
- Soot blowers to accommodate the increased quantities of ash.

The CWM fuel concept is expected to be applicable in developed, industrializing, and developing countries (Szpunar and Gillette 1990) and in Hawaii. The designs are somewhat similar to those using other fuel systems; however, Hawaii would probably not be inclined to be one of the first commercial users of this or any other first-generation technology, despite its special applicability to an island situation.

A.3 SLAGGING COMBUSTORS

Slagging combustors (including advanced cyclone combustors) burn coal, simultaneously controlling SO_2 , NO_x , and particulate levels during the combustion process. The combustor is attached to the boiler. The inlet to the combustor has air and fuel connections. Internally, the ash is separated in a molten phase from the combustion gases by a swirling action before the hot exhaust gases enter the boiler. To control SO_2 emissions, a sorbent (usually limestone) is usually injected into the combustor, and the product CaSO_4 is removed with the slag. Formation of NO_x is inhibited by maintaining a fuel-rich environment during initial combustion, followed by a fuel-lean combustion zone. The solid products from the combustor consist of ash, calcium and sulfur compounds, and unused calcined limestone.

The major markets for slagging combustors are in areas where oil-fired plants are currently in use (for example, the Hawaiian Islands). The primary thrust of this process is to remove sufficient ash so that oil-fired boilers can be used in a coal-burning mode. The reductions in SO_2 and NO_x emissions are added benefits. Although usually considered a retrofit technology, new boilers of this type could be designed. Extensive research and development (R&D) have been carried out by private U.S. firms. Coal type is not a limiting feature, but higher ash coals and those with poor slagging characteristics are less desirable. Flexibility of coal use and compactness of size are advantages.

In one form of the slagging combustor, the fuel is injected radially from a central injector, whereas the air is fed tangentially around the periphery. The interaction of the air moving circumferentially and the coal particles or droplets moving axially and radially outward results in a continuous flow of air across a burning particle, thereby providing more rapid and efficient combustion of the coal. Points of air injection can be placed in such a manner as to provide staged combustion to control NO_x formation. Reduction of NO_x by 50-70% relative to wall-fired PC combustors is achieved.

Injection of sulfur sorbent, either with the fuel or separately into the combustor or into the combustion gases, eliminates the need for an FGD system. Control of SO_2 is achieved by the injection of alkali compounds (e.g., limestone) during combustion or with the fuel. An SO_2 emissions reduction of 50-90% may be achieved. The slagging combustor controls particulate emissions by converting the ash into molten slag which, together with the solid sulfites and sulfates produced by the injection of limestone, is removed before the hot gases enter the boiler or heater passage areas.

A.3.1 Applicable Market

Slagging combustors can replace oil- and gas-fired combustors in large-scale commercial, industrial, and utility settings. In the United States, approximately 60,000 coal-, gas-, and oil-fired combustors are candidates for slagging-combustor retrofit (Szpunar and Gillette 1990). (Of these, utilities operate 33,000, and industries operate

25,000.) In Hawaii, approximately 1,000 MW of oil-fired capacity may be considered for retrofit.

Commercial and industrial applications include steam production for process heating, site heating, and electricity production in cogeneration units. Utility applications involve producing steam for generating electricity. Because of their compactness, slagging combustors are especially desirable for plants with space constraints. Oil-fired boilers are particularly suitable for slagging-combustor retrofit; derating is minimal for this application. Also, existing coal burners can be retrofitted for greater reductions in pollutant emissions.

A.3.2 Commercialization Status

Since 1988, Coal Tech Corp. and TRW have been marketing industrial slagging combustor systems. These companies have partially demonstrated their technology in industrial settings. Both combustors burn PC, with the ability to burn CWMs in the offing. Programs to demonstrate utility boilers are underway.

In early 1989, several companies were preparing to sell slagging combustor systems; however, realistic commercialization of this technology, such that customers could choose among several systems with identical thermal capacities and pollutant emission specifications, was not expected until at least the mid-1990s.

Regarding its clean coal technology (CCT) demonstration completed in the fall of 1991, Coal Tech Corp. concluded that "while the combustor is not yet fully ready for sale with commercial guarantees, it is ready to be further scaled up for commercial applications (100×10^6 Btu/h), such as combustion of waste solid fuels, limited sulfur control in coal-fired boilers, and conversion of ash to slag" (DOE 1993, pp. 7-10 and 7-11). Coal Tech's advanced, air-cooled slagging combustor is advertised as using a wide range of coals and as able to be used as a retrofit or in new units. The target market is industrial and utility boilers sized $20\text{-}100 \times 10^6$ Btu/h or more, with multiple combustors attached to form larger units. The near-term focus is on using the combustor in combined-cycle industrial and small utility power plants in the 10-50-MW range (DOE 1993).

Other companies developing slagging combustor technology include Avco Research Laboratory, Progress Technology Corp., Energy and Environmental Research, and Transalta (Ruth and Payne 1987). Transalta bought into Rockwell International's slagging combustor technology development.

A.3.3 Plant Size and Modularity Considerations

Industrial and commercial slagging combustors of the size range applicable in Hawaii (1-20 MW) have been built and operated at atmospheric pressure for thousands of hours (Szpunar and Gillette 1990). Units larger than 20 MW have only been designed. Coal Tech's target market is industrial and utility boilers sized $20\text{-}100 \times 10^6$ Btu/h or more, with multiple

combustors attached to form larger units. The near-term focus is on using the combustor in combined-cycle industrial and small utility power plants in the 10-50-MW range (DOE 1993).

Because utility boilers require combustion heat release ratings an order of magnitude higher than those projected, scaling up is a concern, but scaling up to utility size can probably be achieved by means of multiple units, just as utilities use a modular approach in achieving high boiler-firing rates. Such modularity has several operational advantages. Partial boiler loads can be handled by using fewer combustors operating at maximum efficiency. In addition, certain repairs and servicing can be accomplished in the inoperative mode. Generally, the modern cyclone types of slagging combustors are the same size as the burner units being replaced. Therefore, in converting from oil (or gas) to coal, the boiler system need not be derated due to physical constraints on the combustor.

Certain components may have to be added at facilities retrofitted with slagging combustors. Because slagging combustors require crushed, pulverized, or slurried coal, coal preparation equipment must be available (Szpunar and Gillette 1990). If limestone injection is used, limestone crushing and handling equipment must be obtained. If the previous fuel was oil (or gas), coal storage equipment must be added. Facilities for storing slag are also necessary. A baghouse may be needed to replace an ESP.

As already mentioned, an 8.7-MW slagging combustor is only 5 ft in diameter and 8 ft long. Relative to fluidized-bed combustors, slagging combustors are compact. Slagging combustors are therefore preferable for facilities having space constraints.

A.3.4 Performance Issues

Combustion efficiency (i.e., carbon conversion) for slagging combustor systems has been demonstrated to exceed 98%. Indeed, 99.5% carbon conversion, as measured by ultimate analysis of slag and effluent, is not uncommon. Projected plant heat rates are in line with other developed combustion systems. Net plant heat rate is estimated to be only slightly higher ($\approx 2\%$) for the slagging combustor than for circulating fluidized-bed combustion (CFBC); however, plant heat rate projections of 9,900 Btu/kW (Szpunar and Gillette 1990) and a heat rate of 9,275 Btu/kW estimated by TRW for the Lovett plant are indicative of the level of uncertainty in the performance of this technology.

A.3.4.1 Plant Complexity and Operability

Because of their small furnace volumes, coal-fired cyclone boilers are excellent candidates for retrofit with slagging combustors. Oil- and gas-fired units are also suitable candidates.

A.3.4.2 Part-Load Operation

Slagging combustors have demonstrated a turndown ratio of 3:1 from maximum rated firing rates in tests lasting hundreds of hours (Szpunar and Gillette 1990). Turndown is governed principally by the need to maintain slag flow. In addition to the inherent reduced firing rate of a given combustion unit, the turndown of a modularized boiler's combustion system can be increased by shutting down banks of combustors. Thus, the turndown is equivalent to that now accomplished with existing combustion systems.

A.3.4.3 Reliability and Availability

Data are limited regarding the reliability and availability of slagging combustor systems, precluding the estimation of realistic projections; however, the 4,000 hours of tests conducted in Cleveland by TRW (Szpunar and Gillette 1990) indicate that the combustor was available more than 90% of the time. The largest contributor to unavailability was the dense-phase coal-transport feed system. The total availability of the TRW demonstration boiler was 83.8%.

A.3.5 Environmental Concerns

A.3.5.1 Atmospheric Emissions

The control of the emissions of gaseous pollutants — NO_x , SO_x , and particulates — for slagging combustor systems is discussed subsequently.

Nitrogen Oxides. The NO_x emission problem has been addressed by using staged combustion. The first stage is operated at a stoichiometry of 0.7, and the overall stoichiometry of the system is greater than one. Excess air is used to keep final temperatures below 2,700-2,900°F (~1,500-1,600°C). The NSPS for NO_x is 450 parts per million (ppm); most staged slagging combustors achieve 200-250 ppm at a stoichiometry ratio of 0.7 in the first stage; however, there is considerable variation in final NO_x levels with first-stage stoichiometry. Thus, good local as well as global mixing and overall control of flow rates are extremely important.

Sulfur Oxides. The reductions in SO_x emissions achieved by slagging combustor systems have not been as universally acceptable as those for NO_x . Claims of up to 90% reduction abound in the literature.

The reduction in SO_2 emissions often depends strongly on the ratio of sorbent to sulfur. At higher sorbent injection rates, more SO_2 is removed. Sorbent economics is a major factor for a given design combustor. Empirically changing the injection conditions and locations is the approach generally taken to optimization. Sulfur dioxide reductions of 50%

at a sorbent-to-sulfur ratio of 3 have been consistently achieved. With fully developed systems at the same sorbent-to-sulfur ratio, 70% reductions seem likely. The issue of steady-state versus transient injection of sorbent, in terms of relative effectiveness, remains unresolved. The claims of 90% SO_2 reduction need to be justified by daily operations; however, during bench-scale tests at Transalta, 90% SO_2 removal was achieved with bituminous and subbituminous coals.

Particulates. Because of high ash retention in the slag, particulates are generally well controlled in slagging combustor systems; however, a fabric-filter baghouse or other cleanup equipment may have to be installed to capture the very fine particles of fly ash and unsulfated sorbent produced during combustion.

A.3.5.2 Production of Solid Waste (and By-Products)

Mineral matter, in the form of slag from the combustor, represents about 80% of total ash input. The remaining ash is collected by bag filters as fly ash in the form of extremely fine particles. Also part of the solid waste stream are CaSO_4 and unsulfated input limestone components (CaO and calcium carbonate). This material is either combined with the slag, in the form of frit, or is collected as fine particles in the baghouse.

A.3.6 General Comments

Although slagging combustors represent a relatively new technology, they offer significant environmental advantages over established coal combustion systems and offer a way to retrofit oil-fired units. Therefore, Hawaii should consider this option accordingly.

There are no special coal-handling requirements other than the addition of a limestone feed system. The slagging combustor produces a molten slag containing the ash and captured sulfur as a solid waste prior to boiler entry, with the removal of ash as slag rejection at 80-90%. Reduction of NO_x is achieved by staged combustion. Coal-water mixtures as fuel can simplify fuel storage, handling, and feed systems. Injection of sulfur sorbent, either with the fuel or separately into the combustor or into the combustion gases, eliminates the need for an FGD system in many applications; and high-sulfur, high-ash, and low-fusion-temperature coals can be used.

A.4 ATMOSPHERIC FLUIDIZED-BED COMBUSTION

A fluidized-bed combustor is a furnace in which a bed of solid particles is suspended in a stream of upward-flowing air. The suspended particles behave like a fluid. During combustion, tubes with flowing water that are located within the bed or above the bed (or both) in the flue gas path are heated to form steam. The steam generated is then sent to a steam turbine for the generation of electricity. The distinctive aspect of FBC is that when coal and a sorbent — such as limestone — are injected into the bed, SO_2 is absorbed by the

sorbent to produce a dry and benign solid. Atmospheric fluidized-bed combustion operates at or near atmospheric pressure (DOE 1987a).

Fluidized-bed combustion has a lengthy history. The concept was first applied to the Winkler coal gasification process in Germany more than 60 years ago (Patterson 1987). During the early 1950s, a fluidized-bed burner (primarily a retrofit device) was developed in France for use in generating steam on a small commercial scale in coal-fired boilers. By the 1960s, basic investigations of FBC were underway in the United Kingdom, the People's Republic of China (PRC), and the United States. The initial emphasis was on AFBC. The renewed interest in this technology during the 1980s can be attributed to its ability to remove SO_2 from flue gas and thereby meet U.S. Environmental Protection Agency (EPA) emission limitations without resorting to installation of costly (FGD) systems (i.e., back-end add-on systems).

In the mid-1970s, skyrocketing oil prices, which favored exploitation of domestic resources, and increased sensitivity to environmental issues heightened interest in AFBC as a power-generating option. In the United States, AFBC research facilities have been sponsored or built by various federal agencies, national laboratories, and private industrial process and engineering firms. Presently, a number of utility demonstration plants are in operation or under construction.

The principal advantages of the technology include increased control of emissions, ability to adapt to low-grade fuels, enhanced heat transfer in the boiler tubes, and significantly smaller boilers, all of which are of interest to Hawaiian energy planners. Currently, AFBC is the primary repowering option for coal firing; and circulating AFBC, with in-bed desulfurization by lime or dolomite injection and intrinsically low- NO_x production, has already become well established.

The FBC concept can be used, usually in combination with a solid material, with solid, liquid, or gaseous fuels. During combustion, air from a distribution chamber separates and suspends or transports the fuel and solid components of the bed. Heat transfer to the boiler tubes is effective at low temperatures (e.g., $1,550^\circ\text{F}$ or 845°C), which enables the efficient use of the SO_2 sorbent, usually limestone. Thermal efficiencies of an AFBC plant are expected to be comparable to those of a PC plant with FGD.

The ability to design AFBC plants for use with various fuel types contributes significantly to the potential for using a variety of coals. Moreover, reasonable changes in coal quality usually do not lead to significant reductions in power output for a given plant design.

The main environmental benefit is removal of about 90% of the generated SO_2 as CaSO_4 in a dry solid waste system. Ash can also be removed easily; however, to meet particulate emission requirements, a baghouse or some other technology to control fines is required. The production of NO_x is reduced because of the low combustion temperatures. The technology appears to be economically and environmentally competitive with other coal-burning technologies, especially for relatively small boilers. As well as being more

environmentally friendly than an uncontrolled PC boiler, relatively small AFBC boilers can match the efficiency of much larger PC boilers, which are handicapped by postcombustion emission control equipment.

The relative ease of operation and maintenance of this technology is evidenced by its use in the industrial sector of the United States and in foreign countries like the PRC. Also, the availability of AFBC in relatively small sizes makes it a viable candidate for use in areas such as Hawaii. Commercial applications for small units are aided by the ease of shop assembly and transportability of units with steaming capacities of up to 200,000 lb/h. The technology is also applicable to extend the life of power plants just by installing new boilers, an option for Hawaii.

A.4.1 Applicable Market

Atmospheric fluidized-bed combustion is applicable to a wide range of markets in which environmental performance and fuel flexibility are considerations. In industry, the principal application is to supply heat for process, agricultural, or community needs. The popularity of AFBC is enhanced by its ability to accept low-quality fuel. The capacity of the industrial boilers ranges from a few thousand to a half million pounds of steam produced per hour, which is equivalent to approximately 50 MW on the upper end. As measured by actual installations and orders, the technology has penetrated many different industrial (e.g., pulp and paper, food processing, cement, and manufacturing) and institutional markets (e.g., universities and army bases).

The utility sector has also become an important market for AFBC technology because of aging power plants, increases in demand for electricity, and ever more stringent environmental requirements for new power plants. In utility applications, AFBC power plants are primarily intended for baseload operation but can function in a cycling capacity. Demonstration studies are underway to examine the effects of turndown at utility scale. The potential for AFBC technology extends beyond conventional uses; for instance, an additional market for AFBC is the cofiring of a boiler using municipal and/or industrial waste as a supplemental fuel. Such a strategy integrates this promising new technology with a recycling methodology to satisfy social needs beyond the production of electricity.

As a repowering technology, AFBC has the potential to significantly extend the operating life of a coal-fired plant. A repowered coal-fired plant retains much of its existing solids-handling equipment and virtually all of its steam cycle, electricity-generating, and power-conditioning hardware. Repowered plants exhibit improved ability to control emissions, increased efficiency in generating electricity, and enhanced operating cost-effectiveness.

The AFBC technology is likely to be selected for new plants being constructed to meet future growth in electric power demand, but not until the long-term reliability of this option has been proven under utility operating conditions and until the full range of conditions under which AFBC power plants are most economic has been established.

Nevertheless, because of its wide-ranging applicability, its fuel flexibility, and its economic and environmental versatility, AFBC technology may fit aptly into Hawaii's energy plans and needs to be considered carefully.

A.4.2 Commercialization Status

The AFBC technology is commercially established for industrial heating. Systems undergoing start-up represent various supplier designs, primary fuels, and fuel combinations. A number of different organizations and electric utilities are collaborating on projects. Recent reports project good potential in both the industrial and utility sectors for new capacity additions or for repowering existing coal-fired plants (DOE 1993).

The AES Barbers Point power plant on the island of Oahu, Hawaii, is a 180-MW AFBC plant that sells power wholesale to the Hawaiian Electric Co. (HECO). The HECO elected to depend on the power from the AES Barbers Point facility, the first large coal-fired plant in Hawaii, in order to reduce its reliance on oil. Emissions control at the plant is accomplished through the use of circulating fluidized-bed (CFB) boilers, selective noncatalytic NO_x-emissions control, and fabric filters for particulate emissions control. Two 50-percent capacity CFB steam generators supply steam for the turbine/generator and a local refinery process. Heat rejection is accomplished by circulating water from the cooling tower through the condenser and auxiliary heat exchangers. Indonesian coal is delivered to the facility from a nearby harbor via an enclosed overland conveyor and is discharged with two lowering wells to storage piles. Limestone from the dredging of local coral deposits is also used at the plant. Process and cooling water comes from on-site saline wells and from the city and county of Honolulu and is treated before being sent to the steam-cycle makeup system (Gunn 1993).

In Poland, for example, although financing is key and being negotiated presently, San Diego-based Pyropower Corp. and ABB Power Generation Ltd. of Baden, Switzerland, are projected to provide AFBC boilers and turbine generators to the Turow Power Plant in Bogatynia, Poland. Pyropower hopes to supply two 230-MW Ahlstrom Pyroflow reheat AFCB boilers — including all equipment, structural steel, and construction — and ABB hopes to furnish two turbine generators and plant controls (*Coal & Synfuels Technology*, March 8, 1993). Additional refurbishment or repowering (or both) is considered likely.

A.4.3 Plant Size and Modularity Considerations

Industrial boilers produce from a few thousand to half a million pounds of steam per hour, which is equivalent to up to approximately 50 MW. Most utility boilers are characteristically larger than the largest industrial units, with a minimum capacity closer to 100 MW. Utility designs are typically modular (to keep the bed tractable), and several bed modules may be contained in a single furnace. The beds are arranged either horizontally (ranch style) or vertically (stacked). The reliability of a string of parallel modules is typically greater than the reliability of a single large unit. An advantageous feature of the larger scale units is the freeboard volume available to further enhance the combustion and sulfur removal

processes begun in the bed. Proper design of the freeboard conditions yields combustion efficiencies near 99% and reductions in required limestone-sorbent consumption ratios (Ca/S) to less than 2:1 (Singer 1981).

Many types and sizes of boiler can be repowered by an AFBC unit using the existing plant area, coal- and waste-handling equipment, and steam turbine equipment, thereby extending the life of a plant (DOE 1993); however, for units larger than 50 MW, the combustion zone area is so large that additional heat removal is required. It can be accomplished directly by increasing the water-wall surface through additional division walls or indirectly by adding an external fluid-bed heat exchanger, whereby a controllable amount of solids can be routed through a heat recovery cooler and then recycled back to the furnace.

A.4.4 Performance Issues

The fluid-like motion of the solids in the combustion chamber promotes turbulent mixing that improves combustion efficiency and the capture of SO₂. The superior mixing also permits combustion at substantially lower and more evenly distributed temperatures, thus reducing formation of NO_x. Combustion occurs at temperatures below the ash melting point, so that solids accumulation and boiler tube erosion and corrosion are minimized (DOE 1987a).

The test results from TVA's pilot-plant (20-MW) study confirmed many of the expectations established for AFBC technology in earlier work in a small-scale unit. The pilot plant operated with Kentucky No. 9 coal for 18,000 hours. Underbed coal feed and recycle of fly ash from the cyclone collectors produced combustion efficiencies of 97%. A weight ratio of recycled fly ash to coal feed of 2.0-2.5 was necessary to achieve this level of efficiency. Underbed feed achieved 90% SO₂ capture at a calcium-to-sulfur ratio of 2.3 and a recycle ratio of 2.5. Overbed feed required higher calcium-to-sulfur and recycle ratios to obtain 90% SO₂ capture (EPRI undated).

A.4.4.1 Plant Complexity and Operability

The wide acceptance of AFBC technology in the industrial sector leads one to conclude that complexity and operability are not barriers to commercialization; however, important technical issues remain unresolved, particularly with respect to larger utility boilers. The most significant issues center on coal and sorbent feeding, sorbent utilization, load control, erosion and corrosion, scaling methods for design of large boilers, and heat transfer.

A.4.4.2 Part-Load Operation

The principal constraint on load control is the narrow range of bed temperatures that allow efficient capture of sulfur with limestone, the preferred sorbent. There appears to be general agreement that sulfur capture is optimal at bed temperatures of 1,550°F ± 50°F

(845°C $\pm$ 30°C). Outside this range, sorbent utilization is apparently reduced, making operations less economic. To circumvent this problem, two basic strategies have been used: bed slumping and velocity turndown (Szpunar and Gillette 1990).

Bed slumping depends on compartmentalizing the fluidizing air distributor such that a portion of the boiler can be defluidized and essentially removed from service. Two important disadvantages of this method are that boiler output tends to change in a stepwise fashion and that restarting slumped compartments can be difficult because of solids clinking, especially with overbed coal feeding.

Small changes in the immersed heat-transfer area can significantly change the heat balance of the bed because of the large in-bed heat-transfer coefficients. Thus, turndown can also be achieved by reducing the air velocity such that the bed level and heat losses are reduced. Therefore, less coal has to be fed to maintain operation in the critical temperature range. To do this over a significant range requires careful modeling of bed expansion and heat-transfer characteristics.

A.4.4.3 Reliability and Availability

In general, the reliability and availability of AFBC systems are expected to surpass those of conventional plants fired with pulverized coal. Technical reports detailing operating experience reveal that many of the problems in demonstration plants have been with auxiliary systems (e.g., fuel-handling, ash-handling, and fly-ash collection systems), rather than with the boiler itself (Szpunar and Gillette 1990).

Commercially operated AFBC plants have begun to provide the first data necessary to allow actual quantitative assessments of reliability. The data show that commercial utility-scale AFBC boilers have availability rates acceptable to the U.S. utility industry and that availability continues to improve with the continued development of AFBC technology.

A.4.5 Environmental Concerns

A.4.5.1 Atmospheric Emissions

Burning coal in AFBC boilers basically produces SO_x, NO_x, and particulates. Sulfur dioxide emissions from a limestone-fed FBC boiler are expected to be comparable to those from a conventional coal-fired power plant with FGD (SO₂ removal on the order of 85-90%), whereas NO_x emissions are expected to be somewhat lower (60-80% [DOE 1993]). Particulate removal is required, but emissions should be comparable in quantity to those from conventional combustion per unit of feed energy fired; however, AFBC particulates are potentially more hazardous because of their size distribution and composition, which make them difficult to capture. The median diameter of particles emitted from AFBC units appears to be smaller than those emitted from conventional coal-fired power plants.

Volatile trace metals and hydrocarbons preferentially condense on the smaller particles, thus potentially increasing their health hazard. Furthermore, FBC fly ash forms at relatively low temperatures and does not fuse like conventional fly ash. For this reason, FBC fly ash can more easily release components such as metals and hydrocarbons. Because of lower operating temperatures and incomplete combustion, FBC is expected to have a higher hydrocarbon emission rate than that for conventional combustion. Results reported from recent studies are in conflict as to the health effects of hydrocarbons from FBC (DOE 1988).

Test results have yielded 70% SO₂ removal efficiency with 1.5 Ca/S (<1,620°F) and 95% SO₂ removal efficiency with 4.0 Ca/S. The NO_x emissions for all tests were less than 0.34 lb/10⁶ Btu, well within the emission limit of 0.60 lb/10⁶ Btu; the average level of NO_x emissions for all tests was 0.18 lb/10⁶ Btu (DOE 1993).

Black & Veatch, Inc. (1992a) has estimated emissions emanating from a generic 180-MW AFBC unit projected to be located in Hawaii. These emissions are based on firing a coal with a calorific value of 12,800 Btu/lb, 1.0% sulfur, 65.1% carbon, and 10.8% ash. These estimated emissions are as follows:

- SO₂ emissions of 0.16 lb/10⁶ Btu,
- NO_x emissions of 0.30 lb/10⁶ Btu,
- CO₂ emissions as a function of the carbon content of the fuel and the calorific value of the feed coal (i.e., based on 100% conversion) of 186 lb/10⁶ Btu,
- CO emissions of 0.11 lb/10⁶ Btu,
- VOC emissions of 0.02 lb/10⁶ Btu, and
- Particulate emissions of 0.015 lb/10⁶ Btu.

A.4.5.2 Production of Solid Waste (and By-Products)

Atmospheric fluidized-bed combustion generates a nonhazardous, dry, benign, solid waste stream that includes coal ash, CaSO₄, unreacted limestone, and other fluidized-bed components. This solid waste is expected to be useful for construction aggregate or other uses. Although such commercial uses are being aggressively investigated, the existence of adequate markets for the volumes predicted to be generated is questionable. The amount of solid waste is a function of how much sulfur must be removed and how much excess limestone must be used. Atmospheric fluidized-bed combustion is expected to generate more solid waste on a dry basis than conventional wet-limestone FGD systems; however, because of its higher density, AFBC waste requires less land for disposal than equivalent amounts of FGD sludge. Black & Veatch, Inc. (1992a) estimates 148 t/d from a 90-MW unit and 295 t/d from a 180-MW unit.

A.4.6 General Comments

Though not appropriate for the situation in Hawaii, for the large number of coal-fired boilers that can be repowered by AFBC using the existing plant area, coal- and waste-handling equipment, and steam turbine equipment, the useful life of the plant can be extended. Although the initial cost may be high, there are no net incremental operating costs; unlike a scrubber, AFBC efficiency is not degraded by parasitic losses. In many cases (e.g., where the capacity of the boiler has been reduced because of aging or the turbine generator has greater capacity than the boiler, or both), AFBC can be used to repower an existing boiler and, in addition to controlling SO₂ and NO_x emissions, can increase the boiler's capacity. The cost of controls can be significantly reduced by the value of the increased capacity (DOE 1987a), assuming there is a convenient market for it.

Internationally, emission standards have been tightened, especially in several European countries and Japan.² This tightening is forcing new approaches and influencing choices among different technologies; for example, simple bubbling fluidized-bed combustion (BFBC) now appears inadequate to meet the strictest standards. Newer and more complicated forms of the technology that employ internal recycle and staged combustion are being considered. The stricter emissions standards are also encouraging adoption of the CFBC technology, particularly for plants of larger capacity.

From an economic perspective, future coal, gas, and oil prices will continue to influence the pace of AFBC development. Given the added flexibility of fuel switching, the argument can be made that all forms of AFBC technology are economically competitive under certain market conditions. Hence, it is recommended that Hawaii consider this option for its specific situations.

A.5 INTEGRATED-GASIFICATION COMBINED-CYCLE SYSTEM

A gasification combined-cycle system gasifies a solid fuel, producing a fuel gas for a combined-cycle power generation system. Typical usable solid fuels include bituminous, lignite, or subbituminous coals. Coal may be delivered to a pressurized gasifier in a coal-water slurry or as a dry feed, depending on the gasifier concept.

In a gasification reactor, coal is reacted with air and steam at a high temperature. This causes the coal to be converted to a raw gas composed predominantly of hydrogen, CO, and H₂S, called raw syngas. The syngas is low-Btu if the gasifier is air-blown and medium-Btu if the gasifier is oxygen-blown. The raw syngas is cooled to 400°F to allow for particulate removal and further cooled to 100°F to allow for acid gas removal (DOE 1987a).

² The typical SO₂ emission standard in Germany, Switzerland, and Sweden is 0.4 lb/10⁶ Btu (even for small plants), whereas the typical U.S. emission standard is 1.2 lb/10⁶ Btu (for plants larger than ~73 MW).

The cleansed gas stream is combusted in a gas turbine. While the gas turbine is similar to engines that power jet aircraft, it is specifically designed to run electrical generators. The combusted gases that exit the gas turbine are still hot enough to generate steam, which can then run a steam turbine to produce additional electricity. The name "combined cycle" is derived from the fact that both gas and steam turbines are in the system (DOE 1987b). Specifically, the gas turbine combustion gases are exhausted to a heat recovery steam generator (HRSG), where high-pressure steam is produced; the cooled combustion gases are subsequently exhausted to the atmosphere. The high-pressure steam formed in the HRSG and in the syngas cooler is used to generate power in a bottoming-steam cycle (Black & Veatch, Inc. 1992a).

The ash, which is not gasified, can be easily separated. The sulfur in the coal which has been converted into H_2S eventually can be converted to elemental sulfur or some other solid waste material (DOE 1987a).

The IGCC technology gasifies coal, removing sulfur, nitrogen, and ash before the derived gas is used in combustion turbines and boilers. Coal gasification takes place at high temperatures in a number of modules, each of which has a capacity of 50 MW. In larger systems, one or more of these modules serve as a spare. The gasifiers can be designed for use with various coals, with most of the designs using oxygen, rather than air. The full-load heat rate is about 9,000 Btu/kWh, with coal characteristics and design specifics influencing the heat rate.

In general, IGCC systems have excellent environmental protection attributes. The gasification and cleanup steps are designed such that SO_2 and particulate emissions from the plants are very low; NO_x formation and emissions can also be kept low. The sulfur removal system can be designed to produce a commercial by-product; and with reduced heat rates, CO_2 emissions are expected to be lower than those from PC plants with FGD.

The EPRI has researched the complete IGCC configuration; development of IGCC concepts has also occurred internationally. Commercially, the concept is ready for application under favorable, project-specific economic conditions. The IGCC technology has the most potential in markets that exhibit high demand for electricity and that can effectively use baseload IGCC units. Applicable in Hawaii, an IGCC system can also be used to repower existing conventional units, thereby improving environmental performance, increasing efficiency, increasing electrical capacity, and extending the useful life of much of the original equipment.

If emission controls continually become more stringent, coal conversion into clean gas before combustion may eventually become a practical necessity; IGCC is the new plant or repowering option that offers the lowest achievable emissions from a coal-fueled plant and high thermal efficiency from relatively small units. Because gases require hot particulate and sulfur cleanup before entering the gas turbine, no flue gas cleanup is required (DOE 1987a).

A.5.1 Applicable Market

An IGCC power plant is intended for baseload electric utility operation, although part-load operation is acceptable from the standpoints of operation and efficiency. In a concept known as "phased addition," natural-gas-fired turbines are installed and operated in a peaking mode. When demand for electricity increases, HRSGs and a steam turbine are installed to create a combined cycle for intermediate or baseload operation. Finally, when economics dictate, gasifiers are added to create the full IGCC plant. As noted previously, the IGCC technology can also be used to repower existing facilities, such as in the situation presented in the Hawaiian Islands.

A.5.2 Commercialization Status

Three gasifier designs are undergoing development at this time. The Cool Water IGCC demonstration project began producing power commercially in mid-1984. The Texaco gasifier option is therefore deemed ready for commercial use, pending favorable economics. One of the DOE CCT-III projects (Tampa Electric IGCC) is scaling this technology up from 100 MW to 260 MW.

A commercial-scale British Gas Corp./Lurgi (BGL) gasifier has been demonstrated in the British Gas Corp. (BGC) facility in Westfield, Scotland. The extensive testing (e.g., load swing simulation) of this gasifier for use in a power plant should allow it to be successfully demonstrated in the early 1990s.

The Kellogg Rust-Westinghouse (KRW) gasifier is in an earlier stage of development and will require further testing, both of the gasifier and the hot-gas cleanup technology. This gasifier could be demonstrated by the late 1990s.

General Electric (GE) has teamed up with Exergy, Inc., of Hayward, California, to improve the efficiency of GE combined-cycle power systems. Recently, GE obtained the license to market and further develop the combined-cycle technology of Alexander Kalina, principal owner of Exergy. The Kalina cycle — expected to be commercially available from GE in 1996 — is reported to increase the thermodynamic availability of energy transferred from the topping to the bottoming cycle. General Electric will use the Kalina cycle as a bottoming cycle for its own combined-cycle systems, which boast efficiency as high as 55%. General Electric and Exergy estimate that the Kalina cycle technology could increase that rating by at least 2%, saving technology users millions of dollars annually in fuel costs (*Coal & Synfuels Technology*, March 1, 1993).

A.5.3 Plant Size and Modularity Considerations

Combined-cycle plants, in addition to increasing the efficiency of energy production, can be composed of standardized modules in 100-200-MW sizes applicable to large and small utilities. This leads to easier installation, less construction time, and relatively lower cost, without the usual economy-of-scale penalties (Szpunar and Gillette 1990).

The Texaco and BGL gasifiers are sized commercially to provide approximately 120-140 MW per unit. Because of the need to provide spare capacity for maintenance or forced outage, one spare gasifier is often specified for a 500-MW plant.

A commercial-scale KRW gasifier has not yet been operated but will probably be about 50 MW. Because of the smaller size of this gasifier, the number of spare gasifiers needed may be about those for the other two options.

An important factor in modularity is the oxygen plant needed to produce medium-Btu coal gas. The cost of this equipment, which depends on its scale, is leading toward a plant size of 500 MW; however, smaller plants have been proposed (Szpunar and Gillette 1990). All three gasifiers operate in the oxygen-blown mode with cold-gas cleanup. Unlike the other two, the KRW gasifier is also being developed to operate in the air-blown mode with hot-gas particulate and sulfur cleanup. If operated in the air-blown mode, IGCC plants may be economic in the 50-100-MW range. This mode of operation has also been proposed for the dry-ash Lurgi gasifier. The CCT-IV TAMCO project being demonstrated currently is compact, reducing space requirements, and is very amenable to smaller capacity, modular construction situations (DOE 1993).

A.5.4 Performance Issues

Data suggest that full-load heat rates for IGCCs with advanced gas turbines run around 9,000-9,100 Btu/kWh; however, the net effective heat rate for the CCT-IV Pinon Pine IGCC demonstration project is projected to be 7,800 Btu/kWh. Also, the KRW system operating on lignite has been shown to be about 10% less efficient (10,040 Btu/kWh) (EPRI 1986b).

A.5.4.1 Plant Complexity and Operability

An IGCC plant combines technologies typical of power plants and chemical plants; therefore, extensive operator training, as was carried out at the Cool Water IGCC plant (EPRI and Radian Corp. 1988), is required. The first-of-its-kind Cool Water plant has received a lot of attention; similar attention would likely be paid to a new IGCC plant in a developing country; however, as the technology matures, plant operation should become more routine. Equipment and feedstock changes should become rare or nonexistent. Since many petrochemical plants are now operated successfully in developing countries, IGCC plants should be no less successful.

A.5.4.2 Part-Load Operation

The gasification trains and gas turbines of IGCC power plants are expected to be modular in design. For this reason, such systems can be expected to experience only moderate increases in heat rate at partial load.

The operating efficiency of an IGCC system at part load was addressed by Stanford University (1987). The analysis considered two cases: (1) as the load dropped, all gasification trains were reduced in operating level equally; and (2) when the load was low enough, one or two of the trains were taken off line. The second case resulted in higher efficiency; for example, by operating only two gas turbines and one oxygen train, as opposed to the three gas turbines and two oxygen trains required for full-power operation, the IGCC system could be operated at 50% load with only a very small increase over the full-load heat rate (Szpunar and Gillette 1990); however, because of the restart requirements for a gasification train, it may be preferable to keep all trains in operation, especially if the drop in load is expected to be of short duration.

A.5.4.3 Reliability and Availability

Experience at Cool Water indicates that a mature plant should be able to achieve availabilities of 68%, with both forced and scheduled outages taken into consideration (Arinc Research Corp. 1988). Furthermore, increased design modularity and more experience in operation and maintenance are expected to allow newer IGCC plants to achieve availabilities in excess of 80% (EPRI 1986b).

A.5.5 Environmental Concerns

A.5.5.1 Atmospheric Emissions

Black & Veatch, Inc. (1992a) reports that typical acid gas removal systems are capable of removing at least 98% of the sulfur content in the coal. Particulates entrained in the raw gas leaving the gasifier may be removed by using a cyclone, by scrubbing with a wet spray-type scrubber, or by filtering with ceramic filters. The NO_x emissions may be controlled by saturating the syngas fuel with water vapor. Flue gases may be discharged through a tall stack, the tallest stack consistent with good engineering practice based on the expected building heights and plan dimensions. This stack may also be used for the combustion turbine bypass and the HRSGs.

The operating permit for the Cool Water plant established far more stringent emission limits for SO_2 , NO_x , and particulates than were required for any other fossil-fuel power plant previously. As shown in Table A.1, these requirements were met or exceeded. Removal levels of SO_2 of 99% and NO_x removal levels of 40% have actually been demonstrated (DOE 1987a). The CCT-II Combustion Engineering IGCC repowering project is expected to have NO_x emissions of less than $0.1 \text{ lb}/10^6 \text{ Btu}$, a reduction of approximately 90% (DOE 1993).

TABLE A.1 Pollutant Emissions from the Cool Water Plant

Pollutant	Emissions (lb/10 ⁶ Btu)		
	EPA NSPS	Plant Permits ^a	Plant Test Results ^b
NO _x	0.60	0.13	0.056
SO ₂	0.24	0.034	0.017
Particulates	0.03	0.01	0.008

^a Cool Water plant permit for low-sulfur coal operation, with low-sulfur coal defined therein as coal containing less than 0.7% sulfur.

^b 1987 EPA performance test results for Sufco coal.

Source: Szpunar and Gillette (1990).

Black & Veatch, Inc. (1992b) has estimated emissions emanating from a generic 230-MW IGCC unit projected to be located in Hawaii. These emissions are based on firing a coal with a calorific value of 12,800 Btu/lb, 1.0% sulfur, 65.1% carbon, and 12.6% ash. These estimated emissions follow:

- SO₂ emissions of 0.03 lb/10⁶ Btu,
- NO_x emissions of 0.08 lb/10⁶ Btu,
- CO₂ emissions as a function of the carbon content of the fuel and the calorific value of the feed coal (i.e., based on 100% conversion) of 186 lb/10⁶ Btu,
- CO emissions of 0.02 lb/10⁶ Btu,
- VOC emissions of 0.013 lb/10⁶ Btu, and
- Particulate emissions of 0.009 lb/10⁶ Btu.

A.5.5.2 Production of Solid Waste

Most IGCC concepts involve generation of dry, benign, solid waste (e.g., elemental sulfur and gasification slag, which includes entrained ash). The disposition of these materials is market-dependent — slag to the construction industry, where it may be used as a

lightweight aggregate construction material, and sulfur to the chemical/fertilizer industry, where it may be used as a feedstock (Black & Veatch, Inc. 1992a).

The quantity of slag produced is a function of several parameters, including the coal used, the efficiency of the plant, and the type of sulfur control. Experimental and estimated values for slag production are about 75-150 lb/MWh. The high end of this range corresponds to high-ash coals and/or in situ (i.e., in the gasifier) sulfur removal (Fluor Engineers, Inc. 1985; EPRI and Radian Corp. 1988). The quantity of sulfur produced depends on the coal used, the efficiency of sulfur removal, and the plant efficiency. Values range from less than 5 lb/MWh for low-sulfur coals to 30 lb/MWh for a high-sulfur Illinois Basin coal (Fluor Engineers, Inc., 1984; EPRI and Radian Corp. 1988). Black & Veatch, Inc. (1992a) estimates that approximately 268 tons of slag and entrained ash per day and 21 tons of sulfur per day may be generated by a 230-MW plant to be located in Hawaii.

A.5.6 General Comments

Fundamental differences exist between power plants based on IGCC technology and those based on standard boilers fired with PC. Energy is extracted at a higher temperature in the gas turbine than is possible in a steam turbine alone. Thus, on thermodynamic grounds, IGCC can theoretically achieve higher efficiencies than a PC plant. Efficiencies should increase as improvements occur in gas turbine technology.

Also, in an IGCC plant, gaseous and solid emissions are dealt with before combustion. The product gas is therefore lower in mass and higher in pressure, which results in a 300-fold decrease in the volume needing treatment for particulate and sulfur removal. This decrease in volume significantly affects plant size and cost. Waste products from an IGCC plant are often in the form of elemental sulfur or sulfuric acid, either of which can be marketed as by-products, which improves the economics of the process. The IGCC spent sorbent is recycled, whereas the sorbent used in a boiler fired with PC is usually a once-through material (e.g., limestone) that must be disposed of with sulfated waste in landfills. Control of NO_x is also easier and more efficient in an IGCC plant.

Innovations in IGCC design will occur both in fundamental aspects (e.g., improvements in hot-gas cleanup and increases in gas-turbine firing temperature) and cycle refinements (e.g., intercooled steam-injected gas turbine). Although coal-fired cycles will never attain the efficiency of natural-gas-fired cycles, the differences should narrow and eventually lead to coal becoming the most economic fuel.

In repowering with IGCC, a gasifier, gas stream cleanup unit, gas turbine, and waste heat recovery boiler are added; in most cases, these replace the existing coal boiler. The remaining equipment is left in place, including the steam turbine and electrical generator. The result is an extension of plant life to essentially that of a new plant, an increase in efficiency from a nominal 35% to over 40%, and an increase in overall plant output of 50-150%, with significantly reduced overall emissions. The incremental cost of the additional capacity is low compared to the cost of a new plant.

In recent years, IGCC has become a rapidly emerging alternative for new electric generating plants. Such plants require 15% less land area than PC plants with FGD and exhibit substantially improved thermal efficiency and environmental performance. Because of its advantages of modularity, rapid and staged on-line generation capability, high efficiency, environmental controllability, and reduced land and natural resource needs, IGCC has become a strong contender in meeting future energy needs (DOE 1993).

For Hawaii, an oxygen-blown system would seem to be just out of reach. Since an oxygen plant is needed to produce a synthetic gas from coal and because its cost is deemed effective for a plant size of approximately 500 MW, IGCC would not be appropriate for the island location, although smaller plants have been proposed; however, if a commercial-scale KRW-type unit is demonstrated successfully in the air-blown mode, an IGCC plant may become economic in the 50-100-MW range, thus making IGCC feasible for Hawaii.

A.6 PRESSURIZED FLUIDIZED-BED COMBUSTION

Pressurized fluidized-bed combustion uses a furnace in which a bed of coal and limestone (sorbent) is suspended in a stream of upward-flowing pressurized air. The suspended particles behave like a fluid. The process involves burning crushed coal under high pressure in a sorbent bed, usually of limestone or dolomite. A compressor provides high-pressure combustion air at the bottom of the combustor to maintain the coal and sorbent in a highly turbulent suspended state. The turbulence promotes good particle mixing, and the bed depth allows long gas residence time, which leads to high combustion efficiency and SO_2 absorption.

During combustion, tubes with flowing water that are located within the bed are heated to form steam. The steam generated is then sent to a steam turbine for the generation of electricity. Increased system efficiency is realized by combined-cycle operation through the incorporation of a gas turbine to recover additional energy from the pressurized products of combustion. A distinctive aspect of FBC is that when coal and a sorbent are injected into the bed, SO_2 reacts with the sorbent to produce a dry and benign solid (DOE 1987b).

In PFBC technology, combustion air is pressurized (10-16 atm) to reduce combustor size and to obtain net power from an expansion turbine-compressor arrangement. The net plant heat rate is expected to be significantly lower than that for an AFBC plant.

Emissions of SO_2 are controlled by use of an SO_2 sorbent, usually limestone or dolomite. Low operating temperatures inhibit NO_x formation. Particulate control in the hot gas flowing to the turbine expander is required for equipment longevity and for reducing or eliminating the need for particulate removal in the plant outlet stream.

Currently, R&D on this concept is occurring worldwide, which probably will result in its commercialization. At this time, the maturity of the technology lags that of the AFBC concept. The PFBC technology is most applicable to the electric utility market and large

industrial power generation applications. Its potential is probably greater as an option for new plants, rather than as a retrofit option for existing plants. Various coal types can be specified.

A.6.1 Applicable Market

The PFBC technology is applicable within a range of markets that include large industrial power-generation systems and electric utilities. The PFBC technology appears to be best suited for utility and industrial applications of 50 MW or larger. Whether and to what extent this technology may be applied in Hawaii remains to be seen.

German experts believe that the PFBC market will become very broad and generalized. They expect the more immediate applications to be for utility power generation and district heating (cogeneration), both of which are considered compatible with PFBC design. This "young" technology already offers significant advantages over conventional power cycles, especially with regard to meeting pollution standards and yielding higher overall energy conversion efficiencies with correspondingly lower capitalization and operating costs.

A.6.2 Commercialization Status

Component testing has produced technical information that should lead to a successful demonstration at the 70-MW (nominal output) CCT-I Tidd PFBC plant. The Tidd plant began operation in 1990, with testing and data collection efforts scheduled originally to continue through 1992. The first PFBC plant in the United States had completed more than 700 hours of continuous operation through mid-1992. Demonstrations are scheduled currently to continue through February 1994 (*Coal & Synfuels Technology*, July 20, 1992), and although the Tidd project is slated for 10 years of operation and includes a three-year test program, commercial commitments are expected in the mid-1990s. For commercial applications, the planned size of the modules is to be scaled up to 320 MW. Commercial units are expected to begin operation after 1995 but before 2000.

In the United States and Canada, Babcock & Wilcox holds the exclusive PFBC license of ABB Carbon of Sweden, its previous joint venture partner (*Coal & Synfuels Technology*, Oct. 12, 1992).

Germany expects trial operation of a complete 330-MW PFBC power-generation system by 1995. The present pilot plant, which represents the current stage of development, is limited to operations at approximately 5% of full scale. The plant is expected to demonstrate only those components directly associated with the combustion system. The turbines and cooling systems are believed to be sufficiently well developed to present no additional problems.

A.6.3 Plant Size and Modularity Considerations

Elevated pressures permit higher combustion intensity and allow for reduced unit size. Combined-cycle plants, in addition to increasing the efficiency of energy production, can be composed of standardized modules. This leads to ease of installation and relatively lower cost without the usual economy-of-scale penalties. Modularity provides for staged construction, which permits smaller increments of capacity, thereby shortening construction time and lowering financing requirements.

At present, the ASEA/Babcock Group has standardized on a 200-MW unit combustion module. The intent is to combine these modules inside a common pressure vessel to permit growth beyond 200 MW. There are plans for a system that incorporates four 200-MW modules for the Philip Sporn plant in New Haven, West Virginia. The pressure vessel for this plant would be 80 ft in diameter and 100 ft high. The costs are expected to be realistic because of the modular nature of construction. Larger plant sizes can be estimated on the basis of combinations of modular components and their associated construction costs.

A.6.4 Performance Issues

Target performance for PFBC is an overall thermodynamic efficiency of 40-42%, which is significantly higher than that for conventional coal-fired plants. The fluid-like motion of the solids in the combustion chamber promotes turbulent mixing that improves the combustion efficiency. With expected increases in operating temperatures, coupled with the use of existing higher temperature materials, projected operating efficiencies could exceed 50%; however, the need to capture sulfur and operate efficient cleanup systems may prevent achieving higher efficiencies. The Germans predict an overall net plant efficiency of 42%, which translates into a heat rate of 8,125 Btu/kWh.

A.6.4.1 Plant Complexity and Operability

Although PFBC-based plants are somewhat more complicated from a process engineering standpoint than conventional coal-combustion plants, this technology is a workable alternative. Combustion occurs at temperatures below the ash melting point, so that solids accumulation and boiler tube erosion and corrosion are minimized.

In addition, training of personnel is not a barrier to commercialization. It is common practice for technically trained personnel to be provided to operate complex systems as part of the overall contract. In the beginning, the plant is operated by vendor-supplied trained personnel, who then train local people "on the job" until they are able to assume full responsibility for operations.

A.6.4.2 Partial-Load Operation

Individual fluidized beds cannot be derated by more than about a factor of 2; however, the bed depth can be lowered, and the heat-transfer surface can be reduced, as was discussed with AFBC. In addition, in the larger modular systems, whole beds can be taken out of service to effect turndown. By adapting this technique, turndowns approaching 4:1 can be realized.

If the supply of bed air, fuel, and water is shut off, the load can be reduced rather quickly. The bed will slump but remain heated for several hours to a temperature above the minimum required for reignition. The major problem with this mode of operation is control of piping wall temperatures within the bed. This piping normally operates at temperatures substantially below that of the bed. When the coolant is shut off, the piping wall temperatures will soar. Provision must be made for steam cooling or bed dumping.

A.6.4.3 Reliability and Availability

The only information available regarding reliability comes from the extensive test and development work done on boiler tubes and gas turbine components at the ASEA component development facility in Sweden. The Tidd demonstration project should generate valuable plant data on reliability and availability. Availability is expected to be high for new systems, but life expectancy has yet to be established.

A.6.5 Environmental Concerns

A.6.5.1 Atmospheric Emissions

Reduced atmospheric pollution is one of the primary selling features of PFBC systems. In situ capture of SO_2 eliminates the need for add-on removal units. More than 90% of the sulfur in high-sulfur coal can be readily captured in first-generation units and approximately 95% in second-generation units with increased sorbent usage using hot gas cleanup systems (Black & Veatch, Inc. 1992a).

Emissions of NO_x depend on the amount of fuel-bound nitrogen, but an emission rate on the order of $0.08 \text{ lb}/10^6 \text{ Btu}$ has been projected. The superior mixing permits combustion at substantially lower and more evenly distributed temperatures. This results in the reduced formation of NO_x . Black & Veatch, Inc. (1992b) estimates NO_x emissions of $0.12\text{-}0.50 \text{ lb}/10^6 \text{ Btu}$ in Hawaii.

Particulate emissions below EPA standards are currently achievable with standard cyclone technology in conjunction with hot-gas ESPs. Black & Veatch, Inc. (1992b) estimates particulate emissions of less than $0.033 \text{ lb}/10^6 \text{ Btu}$ in first-generation systems and less than $0.001 \text{ lb}/10^6 \text{ Btu}$ in second-generation units using hot gas cleanup systems. In addition, the

higher efficiency of PFBC systems results in less CO_2 being produced than with conventional coal-combustion technology.

A.6.5.2 Production of Solid Waste (and By-Products)

A PFBC plant produces about twice as much solid waste needing disposal as a conventional coal-combustion plant; however, the waste generated is a dry, benign solid that can be disposed of or usefully employed (e.g., as material for road or building construction). Sorbent can be recycled within the bed to maximize the uptake of sulfur through formation of CaSO_4 . The Germans hope to market gypsum to their building industry. The extent to which this by-product can be profitably marketed remains to be determined.

A.6.6 General Comments

Although the Tidd project uses high-sulfur bituminous coal from Ohio as the basis for design, PFBC plants are expected to be able to fire a wide range of coals. Moreover, no technical problems are anticipated in meeting NSPSs with PFBC units; however, as with all new technologies, costs and reliable performance are major issues. Many of the physical operating parameters for the pilot plants (e.g., combustor operating pressure and temperature and steam conditions) are quite similar. These similarities are in part attributable to a worldwide information network and the optimal temperature region for SO_2 capture by the sorbent. The results of tests and economic studies suggest that the PFBC concept will be ready for commercialization in the mid- to late-1990s.

By repowering a boiler to PFBC technology using the existing plant area, coal- and waste-handling equipment, and steam turbine equipment, the life of a plant can be extended. Although the initial cost may be somewhat high, there are no net incremental operating costs; unlike a scrubber, PFBC efficiency is not degraded by parasitic losses. Also, the addition of the gas turbine can provide an increase in plant capacity of about 40%.

Although impressive from the economic, environmental, and efficiency perspectives, whether and to what extent this technology offers potential for Hawaii remains to be seen. The projected optimal size (>300 MW) seems to be the biggest deterrent for practical application; however, a 200-MW unit might bring the technology back into the range of possible alternatives for this island location.

A.7 COAL BENEFICIATION

In general, beneficiation processes reduce the ash and inorganic sulfur content of coals. Advanced coal preparation processes are being developed to further reduce ash and sulfur content and to increase Btu recovery, generally by reducing the moisture content.

The environmental benefits of advanced coal preparation processes derive mainly from lower SO_2 emissions and decreased amounts of ash to be collected and disposed of at

the ultimate point of consumption, such as a power plant. Lower ash levels also improve power plant operation; however, some of these beneficiation processes yield a product that costs more to ship because of the smaller particle size and the amount of associated moisture incurred.

Coal beneficiation can take place either in the country of origin or in the importing country. Because the costs and associated benefits largely depend on the coal involved, little can be ascertained without investigation and analysis of specific coals in particular situations. Two current CCT demonstration projects are noteworthy, may be of interest to Hawaiian planners, and are mentioned briefly in the following paragraphs.

A.7.1 Advanced Coal Conversion Process Demonstration

Rosebud SynCoal Partnership is sponsoring demonstration of Western Energy Company's advanced coal conversion process for upgrading low-rank subbituminous and lignite coals (CCT-I). The objective is to produce a stable coal product with a moisture content as low as 1%, sulfur content as low as 0.3%, and calorific value of up to 12,000 Btu/lb. Plant operations are underway. Initial shipments of approximately 2,100 tons of SynCoal™ product were delivered for trial burns in Billings, Montana (DOE 1993).

A.7.2 Self-Scrubbing Coal™

Custom Coals International, a joint venture between Genesis Coals Limited Partnership and Genesis Research Corporation, is demonstrating advanced coal-cleaning processes (CCT-IV) to produce low-cost compliance coals that can meet full requirements for commercial-scale utility power plants to satisfy the provisions of the 1990 Clean Air Act Amendments (CAAA). An advanced coal-cleaning plant is being designed to produce, from high-sulfur bituminous feedstocks, two types of compliance coals — Carefree Coal™ and Self-Scrubbing Coal™. The former is produced by using innovative dense-media cyclones and finely sized magnetite to remove up to 90% of the pyritic sulfur and most of the ash. The latter is produced by taking the former, with its reduced pyritic sulfur and ash contents, and adding to it sorbents, promoters, and catalysts (DOE 1993).

APPENDIX B:
OTHER POTENTIAL ISSUES ASSOCIATED
WITH WASTE MANAGEMENT

APPENDIX B:

OTHER POTENTIAL ISSUES ASSOCIATED WITH WASTE MANAGEMENT

The most immediate impacts on coal combustion waste management options come from the RCRA and international agreements on solid and hazardous waste, but other legislative, policy, and regulatory actions can also impact waste management. Understanding trends in pollution prevention and multimedia permitting, as well as the implications of the Comprehensive Environmental Response, Compensation, and Liability Act of 1980 (CERCLA) for coal combustion waste management, can help managers reduce design and operating costs and avoid potential problems. This appendix addresses these potential action areas.

B.1 POLLUTION PREVENTION

Currently, the U.S. Congress and the EPA favor pollution prevention over the more traditional command-and-control or "end-of-the-pipe" treatments to address environmental contamination. Pollution prevention is the use of materials, processes, or practices that eliminate or reduce the creation of wastes at the source. The Pollution Prevention Act of 1990 established a pollution prevention hierarchy of (1) source reduction, (2) recycling, (3) environmentally sound treatment, and (4) environmentally sound disposal — in descending order of preference. No law or regulation mandates pollution prevention activities by the electric utility industry, but this can easily change. The Emergency Planning and Community Right To Know Act (EPCRA)¹ requires industries with Standard Industrial Classification (SIC) codes 20 through 39 (mostly manufacturing sectors) to report annually on nonpermitted releases of 17 specified chemicals to land, water, and air. The EPCRA also gives the EPA the authority to expand the coverage of industries required to report and to increase the number of chemicals on which to report. Several congressmen and EPA staff favor adding electric utilities to the list of industries required to file toxic release inventory (TRI) reports.

The implications of having to file TRI reports are threefold: (1) reporting adds to the paperwork burden, (2) reports are publicly available and could lead to negative publicity, and (3) reporting triggers additional pollution prevention responsibilities. The Pollution Prevention Act of 1990 requires that any operator required to file a TRI report under EPCRA must include with that report an additional report that describes chemical source reduction and recycling activities for the previous year for each chemical reported in the TRI. Operators must prepare such reports for each facility and must include, among other things, quantities of chemicals released to the environment, percent change from previous year, amounts recycled, source-reduction practices used, projected amounts released and recycled

¹ The EPCRA is also Title III of the Superfund Amendments and Reauthorization Act of 1986.

for the next two years, techniques used to identify source-reduction opportunities, amounts treated at the facility, etc.

By taking a proactive approach in the areas of pollution prevention and source reduction, a utility can do much to enhance its public image, improve environmental conditions, and save money; for example, a utility can avoid generating certain wastes by selecting processes and materials that do not produce these wastes. Implementing pollution prevention practices not only reduces waste disposal costs but also often leads to more efficient operations. By undertaking these measures before they are actually required, the utility can save money and improve relations with the community and regulators. Many techniques can reduce or eliminate pollution at the source; details and economic environmental impacts of various pollution prevention approaches should be evaluated in a separate study.

B.2 MULTIMEDIA PERMITS

Historically, the EPA has issued discharge-specific permits for individual pollutants within a facility. Unfortunately, this approach can cause pollutants to be transferred from one medium to another, with no overall reduction in pollution. A single coordinated operating permit could cause less waste to be generated and provide cost savings for companies. The EPA has been talking about this concept for years; and in 1991, the EPA's National Advisory Council for Environmental Policy and Technology (NACEPT) issued a report recommending that the EPA pursue multimedia regulatory approaches (*Daily Environment Report* 1992a). The NACEPT warned that lack of coordination between permittees and regulators blocks innovative technology and suggested development of a model state's program to issue multimedia permits. Subsequently, New Jersey began a pilot program that incorporates pollution prevention provisions into a single operating permit for all pollution sources at a facility. Similar programs are beginning in other states. In addition, the EPA recently instituted a trial multimedia approach for compliance plans at federal facilities, wherein compliance strategies consider the release of all pollutants to all media. This approach may eventually transcend the EPA and become federal law (*Daily Environment Report* 1993a).

Integrating environmental protection across media using pollution prevention to reduce the net output of pollution is becoming increasingly widespread. Carol Browner, EPA Administrator, favors regulations based on pollution prevention and ecosystems approaches (where plans for an entire area, rather than individual discharge points, are developed), more so than end-of-the-pipe approaches (*Daily Environment Report* 1993b). To ensure compliance and positioning for new laws and regulations that pertain to solid waste as a part of overall environmental management, utility planners and developers should carefully monitor these multimedia and ecosystem trends.

B.3 POTENTIAL CERCLA LIABILITY

The Comprehensive Environmental Response, Compensation, and Liability Act of 1980 allows the federal government to compel private parties to perform cleanup or to initiate cleanup and then seek reimbursement of cleanup costs from responsible parties for sites that have been placed on the National Priorities List (NPL or Superfund). A critical component of the law pertains to liability. Potentially responsible party (PRP) liability is retroactive (liable to actions prior to CERCLA), strict (liable regardless of fault), and joint and several (liable for the entire cleanup cost). Liable parties include current and former owners, operators, generators, and transporters.

Liability under CERCLA could affect utility owners in two key ways. First, if the site of the proposed facility had been used for hazardous waste generation, storage, disposal, or treatment prior to purchase by the utility and if the site eventually became a Superfund site, the utility could be liable for 100% of any cleanup costs. Bills are often introduced in Congress to eliminate or cap this "innocent landowner" liability; but so far, the statute has not been changed to weaken this provision. Thus, prior to purchase, the utility must engage in a survey of the land to ensure that there are no hazardous materials on-site that could cause the site to become a Superfund site.

The second issue is the potential for a coal combustion waste disposal area to become a Superfund site. The EPA uses a methodology known as the hazard ranking system (HRS) to score each candidate NPL site. If the HRS produces a score greater than 28.5, the site will be listed on the NPL and become a Superfund site. For years, the utility industry has argued that the HRS is unfairly biased against high-volume, low-hazard wastes. In 1986, Congress passed the Superfund Amendments and Reauthorization Act of 1986 (SARA), which required the EPA to amend the HRS to include additional factors and, responding to the electric utility industry lobby, to address facilities that contain substantial volumes of coal combustion wastes. Section 125 of CERCLA details these coal combustion waste provisions. Although the EPA revised the HRS in 1990 (55 FR 51532), the electric utility industry is still concerned that the revised HRS does not adequately address the unique characteristics of coal combustion wastes and that many utility waste disposal sites will still score high enough to become Superfund sites. The EEI is currently negotiating with the EPA to develop a plan that would be more equitable, but these negotiations are nowhere near completion; and it is possible that the revised HRS will yield scores for several utility disposal sites greater than 28.5, and hence they will be listed as NPL sites (Novak 1993). Becoming a Superfund site carries with it large cleanup and litigation costs, as well as negative publicity. Being aware of the potential issues associated with CERCLA can help reduce potential negative economic or public exposure.

APPENDIX C:
ESTIMATION OF COSTS OF COAL TRUCK TRAFFIC

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ESTIMATION OF COSTS OF COAL TRUCK TRAFFIC

Given sufficient information, it is possible to develop an estimate of the magnitude of the costs (both internal and external) attributable to increased truck traffic. Small et al. (1989) extended previous work conducted by the American Association of State Highway and Transportation Officials to develop an equation that can be used to estimate the number of passages of a vehicle before the road surface in question will have to be replaced. The relationship accounts for the number of axles on the vehicle, the amount of weight per axle, and the type of road surface in question. The relationship is expressed mathematically as:

$$N_i = A_0(D + 1)^{A_1}(L_1 + L_2)^{A_2}(L_2)^{A_3} \quad (C.1)$$

where

N_i = number of passages of each axle of type i ;

D = a measure of the road's durability; for rigid pavements, D equals the thickness of the road measured in inches. For flexible pavements, D is calculated as $0.44(\text{pavement thickness}) + 0.14(\text{base thickness}) + 0.11(\text{subbase thickness})$;

L_1 = the weight (in pounds) of axle i ; and

L_2 = 1 if axle i is a single axle and 2 if axle i is part of a tandem axle.

A_0 , A_1 , A_2 , and A_3 are parameters that take on different values depending on whether the road surface is smooth or rigid. For rigid pavements, $A_0 = 733,073$, $A_1 = 5.041$, $A_2 = 3.241$, and $A_3 = 2.27$. For flexible pavements, $A_0 = 173,165$, $A_1 = 7.761$, $A_2 = 3.652$, and $A_3 = 3.238$ (Small et al. 1989).

Equation C.1 can be used to estimate the number of truck passages over a particular stretch of road before the road will require resurfacing. Once the number of truck passages is calculated, this information could be combined with data on the cost per mile per lane to resurface the road in order to determine the cost per trip per mile attributable to the truck transport of coal.

An unpublished white paper being prepared by Resources for the Future suggests a method for transforming the cost estimate noted previously to estimate the cost of pavement wear per kilowatt-hour of electricity produced. Letting R represent the cost of pavement wear per mile and dividing by W , which represents the weight of the coal carried by the truck, yields the cost of pavement wear per pound of coal per mile, $C_{\text{lb-m}}$. Dividing this figure by the heat value, H , of the coal (measured in Btu) being shipped yields the cost of pavement wear per Btu per mile, $C_{\text{Btu-m}}$. Multiplying the resulting figure by the efficiency of the utility plant, which is measured in Btu per kilowatt-hour yields the pavement cost per kilowatt-hour

per mile, $C_{\text{kWh-m}}$. Finally, multiply this figure by the number of miles traveled from the source of the coal to the generating facility to yield the pavement wear cost per kilowatt-hour of electricity generated at the plant, C_{kWh} .

APPENDIX D:
REFERENCE DATA FOR ATEM

TABLE D.1 Reference Data^a

Technology Name	AFBC-184	AFBC-92	AFBC-30	AFBC-15	PFBC-30	PC-184	PC-92	PC-30
Plant Capacity (MW)	184	92	30	15	30	184	92	30
Fuel Source	Coal	Coal	Coal	Coal	Coal	Coal	Coal	Coal
Capital Cost (\$/kW)	2177	2541	4158	4763	6700	2329	2771	3931
Capital Escal. Rate (%/yr)	0	0	0	0	0	0	0	0
Discount Rate (%/yr)	5	5	5	5	5	5	5	5
Cap. Rec. Factor (%/yr)	6.51	6.51	6.51	6.51	6.51	6.51	6.51	6.51
Fixed O&M Cost (\$/kW-yr)	55.48	78.56	202	329	320	58.81	85.32	221
Var. O&M Cost (mills/kWh)	3.61	3.8	4.53	4.67	5	3.43	3.64	2.7
O&M Escal. Rate (%/yr)	0	0	0	0	0	0	0	0
Fuel Cost (\$/MMBtu)	2	2	2	2	2	2	2	2
Fuel Escal. Rate (%/yr)	0	0	0	0	0	0	0	0
Plant Lifetime (yr)	30	30	30	30	30	30	30	30
Heat Rate (Btu/kWh)	10250	10220	13400	13730	11000	10070	10050	12960
Sulfur Content (%)	1	1	1	1	1	1	1	1
Ash Content (%)	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6
Fly Ash Fraction (%)	100	80	80	80	80	80	80	80
Calorific Val (Btu/lb)	12800	12800	12800	12800	12800	12800	12800	12800
Sulfur Control (%)	90	90	90	90	90	90	90	90
TSP Control (%)	99.9	99.8	99.8	99.8	99.8	99.8	99.8	99.8
NO _x Control (%)	60	60	60	60	60	60	60	60
Emissions (lbs/kWh)								
SO ₂	1.52E-03	1.52E-03	1.99E-03	2.04E-03	1.63E-03	1.49E-03	1.49E-03	1.92E-03
NO _x	2.93E-03	2.92E-03	3.83E-03	3.93E-03	3.15E-03	2.88E-03	2.87E-03	3.71E-03
CO ₂	2.01E+00	2.00E+00	2.63E+00	2.69E+00	2.16E+00	1.97E+00	1.97E+00	2.54E+00
CO	2.64E-04	2.63E-04	3.45E-04	3.54E-04	2.84E-04	2.60E-04	2.59E-04	3.34E-04
TSP	1.01E-04	1.61E-04	2.11E-04	2.16E-04	1.73E-04	1.59E-04	1.58E-04	2.04E-04
VOC	2.80E-05	2.79E-05	3.66E-05	3.75E-05	3.01E-05	2.75E-05	2.75E-05	3.54E-05
CH ₄	4.96E-04	4.95E-04	6.49E-04	6.65E-04	5.32E-04	4.87E-04	4.86E-04	6.27E-04

TABLE D.1 (Cont.)

Technology Name	GCC-232	GCC-30	OILCC-233	OILCC-81	OILST-184	OILST-92	OILST-30
Plant Capacity (MW)	232	30	233	81	184	92	30
Fuel Source	Coal	Coal	Low Sulfur Fuel Oil	Low Sulfur Fuel Oil	Low Sulf. Fuel Oil	Low Sulf. Fuel Oil	Low Sulf. Fuel Oil
Capital Cost (\$/kW)	2816	5500	1003	1085	1467	1763	2244
Capital Escal. Rate (%/yr)	0	0	0	0	0	0	0
Discount Rate (%/yr)	5	5	5	5	5	5	5
Cap. Rec. Factor (%/yr)	6.51	6.51	6.51	6.51	6.11	6.11	6.11
Fixed O&M Cost (\$/kW-yr)	90.08	250	26.8	33.64	23.6	35.44	106.1
Var. O&M Cost (mills/kWh)	4.83	2.5	7.3	8.16	0.72	0.94	0.8
O&M Escal. Rate (%/yr)	0	0	0	0	0	0	0
Fuel Cost (\$/MMBtu)	2	2	4	4	4	4	4
Fuel Escal. Rate (%/yr)	0	0	0	0	0	0	0
Plant Lifetime (yr)	30	30	30	30	35	35	35
Heat Rate (Btu/kWh)	9790	11500	8780	12700	10100	10090	13810
Sulfur Content (%)	1	1	0.5	0.5	0.5	0.5	0.5
Ash Content (%)	12.6	12.6	0.05	0.05	0.05	0.05	0.05
Fly Ash Fraction (%)	80	80	0	0	0	0	0
Calorific Val (Btu/lb)	12800	12800	19065	19065	19065	19065	19065
Sulfur Control (%)	98	98	90	90	90	90	92
TSP Control (%)	99.9	99.9	0	0	50	50	70
NO _x Control (%)	90	90	0	0	0	0	70
Emissions (lbs/kWh)							
SO ₂	3.06E-04	3.59E-04	4.63E-03	6.70E-03	5.33E-03	5.33E-03	5.83E-03
NO _x	7.00E-04	8.22E-04	3.57E-03	5.16E-03	7.13E-03	7.12E-03	2.93E-03
CO ₂	1.92E+00	2.25E+00	1.46E+00	2.12E+00	1.68E+00	1.68E+00	2.30E+00
CO	2.52E-04	2.96E-04	2.93E-04	4.24E-04	3.37E-04	3.37E-04	4.61E-04
TSP	7.71E-05	9.06E-05	2.30E-04	3.33E-04	1.32E-04	1.32E-04	1.09E-04
VOC	2.68E-05	3.14E-05	7.68E-04	1.11E-03	8.83E-04	8.82E-04	1.21E-03
CH ₄	4.74E-04	5.57E-04	9.27E-04	1.34E-03	1.07E-03	1.07E-03	1.46E-03

TABLE D.1 (Cont.)

Technology Name	OILST-15	OILCT-81	OILCT-63	OILCT-22	ADV. OILCT-26	DIESEL-15	DIESEL-26
Plant Capacity (MW)	15	81	63	22	26	15.2	26.6
Fuel Source	Low Sulf. Fuel Oil	No. 2 Fuel Oil	No. 2 Fuel Oil	No. 2 Fuel Oil	No. 2 Fuel Oil	No. 2 Fuel Oil	No. 2 Fuel Oil
Capital Cost (\$/kW)	2648	853	1337	1512	1800	1773	1517
Capital Escal. Rate (%/yr)	0	0	0	0	0	0	0
Discount Rate (%/yr)	5	5	5	5	5	5	5
Cap. Rec. Factor (%/yr)	6.11	6.51	6.51	6.51	6.51	6.51	6.51
Fixed O&M Cost (\$/kW-yr)	181.13	33.64	84.02	113.93	150	111.18	72.33
Var. O&M Cost (mills/kWh)	0.83	8.16	0.93	1.32	1.6	2.63	2.59
O&M Escal. Rate (%/yr)	0	0	0	0	0	0	0
Fuel Cost (\$/MMBtu)	4	4	4	4	4	4	4
Fuel Escal. Rate (%/yr)	0	0	0	0	0	0	0
Plant Lifetime (yr)	35	30	30	30	30	30	30
Heat Rate (Btu/kWh)	14160	12700	8120	11680	9900	10500	10500
Sulfur Content (%)	0.5	0.4	0.4	0.4	0.4	0.4	0.4
Ash Content (%)	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Fly Ash Fraction (%)	0	0	0	0	0	0	0
Calorific Val (Btu/lb)	19065	19700	19700	19700	19700	19700	19700
Sulfur Control (%)	92	90	90	90	90	90	90
TSP Control (%)	70	50	50	50	50	50	50
NO _x Control (%)	70	0	0	0	0	0	0
Emissions (lbs/kWh)							
SO ₂	5.98E-03	5.77E-03	3.69E-03	5.30E-03	4.50E-03	4.77E-03	4.77E-03
NO _x	3.00E-03	1.84E-03	1.17E-03	1.69E-03	1.43E-03	1.52E-03	1.52E-03
CO ₂	2.36E+00	2.09E+00	1.34E+00	1.92E+00	1.63E+00	1.73E+00	1.73E+00
CO	4.72E-04	4.55E-04	2.91E-04	4.19E-04	3.55E-04	3.77E-04	3.77E-04
TSP	1.11E-04	1.61E-04	1.03E-04	1.48E-04	1.26E-04	1.33E-04	1.33E-04
VOC	1.24E-03	1.19E-03	7.63E-04	1.10E-03	9.31E-04	9.87E-04	9.87E-04
CH ₄	1.50E-03	1.34E-03	8.57E-04	1.23E-03	1.05E-03	1.11E-03	1.11E-03

^a All unit data are from Black & Veatch, Inc. (1993).

APPENDIX E:
SAMPLE ANALYSIS SPREADSHEET

BASE YEAR FOR COSTS: AVAILABLE TECHNOLOGIES	TITLE: Baseline Analysis			
	1993 CURRENT YEAR:		1993	
	OPTION 1	OPTION 2	OPTION 3	OPTION 4
AFBC-184				
AFBC-92	X	x	x	
PC-184				
PC-92				
GCC-232				
OILCC-223				
OILST-184				
OILST-92				
OILCT-81				

EXTERNALITY VALUE (\$/TON)

SO2	200
NOX	0
CO2	0
CO	0
TSP	0
VOC	0
CH4	0

TECHNOLOGY COST AND OPERATIONAL DATA

TECHNOLOGY NAME	CONV	CONV W/EXT	ADV W/EXT
UNIT CAPACITY (MW)	92.00	92.00	92.00
FUEL SOURCE	IMPORTED	IMPORTED	IMPORTED
CAPITAL COST (\$/KW)	2541	2541	2795
CAPITAL ESCAL. RATE (%/YR)	0.00	0.00	0.00
DISCOUNT RATE (%/YR)	5.00	5.00	5.00
CAP. REC. FACTOR (%/YR)	6.51	6.51	6.51
FIXED O&M COST (\$/KW/YR)	89.90	89.90	98.89
VAR. O&M COST (MILLS/KWH)	3.89	3.89	3.54
O&M ESCAL. RATE (%/YR)	0.00	0.00	0.00
FUEL COST (\$/MMBTU)	2.00	2.00	2.00
FUEL ESCAL. RATE (%/YR)	0.00	0.00	0.00
UNIT LIFETIME (YR)	30	30	30
HEAT RATE (BTU/KWH)	10220	10220	10220
SULFUR CONTENT (%)	1.00	1.00	1.00
ASH CONTENT (%)	12.60	12.60	12.60
FLY ASH FRACTION (%)	80.00	80.00	80.00
FUEL HEATING VALUE (BTU/LB)	12800	12800	12800
SULFUR CONTROL (%)	90.00	90.00	99.00
TSP CONTROL (%)	99.80	99.80	99.80
NOX CONTROL (%)	60.00	60.00	60.00

FIGURE E.1 Sample Analysis Spreadsheet

EMISSION (LBS/KWH)
RATES

SO2	0.00E+00	1.52E-03	1.52E-04
NOX	0.00E+00	2.92E-03	2.92E-03
CO2	0.00E+00	2.00E+00	2.00E+00
CO	0.00E+00	2.63E-04	2.63E-04
TSP	0.00E+00	1.61E-04	1.61E-04
VOC	0.00E+00	2.79E-05	2.79E-05
CH4	0.00E+00	4.95E-04	4.95E-04

TRADITIONAL ANNUALIZED COST OF ELECTRICITY (INCLUDES ESCALATION)

CAPITAL (\$/KW-YR)	165.30	165.30	181.83
FIXED O&M (\$/KW-YR)	89.90	89.90	98.89
TRAD. FIXED COSTS (\$/KW-YR)	255.20	255.20	280.72
VAR. O&M (CENTS/KWH)	0.39	0.39	0.35
FUEL (CENTS/KWH)	2.04	2.04	2.04
TRAD. VAR. COSTS (CENTS/KWH)	2.43	2.43	2.40

EXTERNALITIES COST OF ELECTRICITY

EXTERNALITIES ESCAL. RATE (%)	0.00	0.00	0.00
FIXED O&M (\$/KW-YR)	0.00	0.00	0.00
EXT. FIXED COSTS (\$/KW-YR)	0.00	0.00	0.00
SO2 (CENTS/KWH)	0.00	0.02	0.00
NOX (CENTS/KWH)	0.00	0.00	0.00
CO2 (CENTS/KWH)	0.00	0.00	0.00
CO (CENTS/KWH)	0.00	0.00	0.00
TSP (CENTS/KWH)	0.00	0.00	0.00
VOC (CENTS/KWH)	0.00	0.00	0.00
CH4 (CENTS/KWH)	0.00	0.00	0.00
OTHER VAR. COSTS (CENTS/KWH)	0.00	0.00	0.00
EXT. VAR. COST (CENTS/KWH)	0.00	0.02	0.00

COMBINED COST OF ELECTRICITY

FIXED COSTS (\$/KW-YR)	255.20	255.20	280.72
VARIABLE COSTS (CENTS/KWH)	2.43	2.45	2.40

CURRENT YEAR COSTS CAPACITY

PLOTTING DATA (\$/KW-YR)	FACTOR	CONV	CONV W/EXT	ADV W/EXT
	0.00	255.20	255.20	280.72
	20.00	297.82	298.09	322.75
	40.00	340.45	340.98	364.78
	60.00	383.07	383.87	406.81
	80.00	425.70	426.76	448.85
	100.00	468.33	469.66	490.88

FIGURE E.1 (Cont.)

LEVELIZATION FACTORS

	CONV	CONV W/EXT	ADV W/EXT
O&M	1.00	1.00	1.00
FUEL	1.00	1.00	1.00
EXTERNALITIES	1.00	1.00	1.00

TOTAL LEVELIZED COSTS (CENTS/KWH)	CAPACITY FACTOR	CONV	CONV W/EXT	ADV W/EXT
	20.00	17.00	17.01	18.42
	40.00	9.72	9.73	10.41
	60.00	7.29	7.30	7.74
	80.00	6.07	6.09	6.40
	100.00	5.35	5.36	5.60

FIGURE E.1 (Cont.)