1 of 1

REGION 3

MARKET DESCRIPTION

SUMMARY

MID-ATLANTIC

PREPARED FOR:

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Preface

The nation is divided geographically into 10 federal regions; 6 of these regions (Federal Regions 2-8) contain 93 percent of the coal-fired power plant units and represent 94 percent of the nation's total coal-fired electric power generation capacity.

The Clean Coal Technology Demonstration Program has undertaken analyses of these regions to assist in developing an understanding of the markets for clean coal technologies (CCTs) and the regional and state factors that could have a bearing on commercial deployment of CCTs.

This summary reports on the analysis of the Mid-Atlantic Region, or Federal Region 3. This region contains 11 percent of the nation's coal-fired units and represents 14 percent of the nation's coal-fired generation capacity.

The *Region 3 Market Description—Summary* provides a condensation of data and information contained in the *Region 3 Market Description—A Region, State, and Utility Overview*. The more comprehensive overview volume contains detailed data and information on (1) regional and state energy, coal use, and electric power generation; (2) state government agencies, including public utility commissions, as well as regulations, legislation, and policies that could have a bearing on CCT commercial deployment; and (3) detailed profiles of 17 investor-owned, cooperative, and municipal coal-using electric utilities in the region, based on integrated resource plans, annual reports, and other publicly available data sources.

Readers should recognize that the information and data contained in this *Summary*, as well as the detailed *Overview*, are changing continually, and the market description is being updated as new information becomes available.

The *Region 3 Market Description—Summary* and its comprehensive companion *Overview* are one set within a series of regional market descriptions which have been or are being prepared and updated as part of the outreach activity of the Clean Coal Technology Demonstration Program.

Introduction

The *Region 3 Market Description—Summary* provides information that can be used in developing an understanding of the potential markets for clean coal technologies (CCTs) in the Mid-Atlantic Region. This region (which geographically is Federal Region 3) consists of the District of Columbia and the following five states:

- Delaware
- Maryland
- Pennsylvania
- Virginia
- West Virginia

In order to understand the potential market, a description is provided of the region's energy use, power generation capacity, and potential growth. Highlights of state government activities that could have a bearing on commercial deployment of CCTs are also presented.

The potential markets characterized in this summary center on electric power generation by investor-owned, cooperative, and municipal electric utilities and involve planned new capacity additions and actions taken by utilities to comply with Phases I and II of the Clean Air Act Amendments (CAAA) of 1990. Regulations, policies, utility business strategies, and organizational changes that could impact the role of CCTs as a utility option are identified and discussed.

The information used to develop the *Region 3 Market Description* is based mainly on an extensive review of plans and annual reports of 17 investor-owned, cooperative, and municipal electric utilities and public information on strategies and actions for complying with the CAAA of 1990.

Regional Overview

The Mid-Atlantic Region is home to 26 million people. The region encompasses highly urban areas in the northeastern part (e.g., Philadelphia and the District of Columbia); in contrast, the western and southern parts of the region are rural, with agriculture and mining dominating the economy. Of the total U.S. population, 10 percent lives in the Mid-Atlantic Region. Population is expected to grow by 8.5 percent between 1990 and 2010, which is significantly slower than U.S. population growth (13 percent).

Between 1990 and 2010, three states are projected to have significant population increases, due primarily to nationwide interstate migration: Delaware, 19 percent; Maryland, 20 percent; and Virginia, 20 percent. DC will grow only slightly (3 percent), and the remaining two states are forecast to lose population—Pennsylvania, -1 percent; and West Virginia, -7 percent.

Coal is an important resource in the region. Pennsylvania, Virginia, and West Virginia offer incentives for clean coal technologies, including tax credits, ratebase treatment for investments in clean coal and clean air technology, and state funding and other support for CCT projects and clean coal research and development.

Coal mining is a major industry in Virginia, West Virginia, and Pennsylvania. The Appalachian Basin coal deposits underlie nearly all of West Virginia and the western parts of Pennsylvania, Maryland, and Virginia. In 1990, 20 percent of all coal delivered to utilities throughout the United States originated from the region. The average sulfur content of the coal deliveries is 1.55 percent, somewhat higher than the U.S. average of 1.35 percent. Sulfur content, in general, is lowest in Virginia, where delivered utility coal originating from the state averages 1.14 percent sulfur, and increases as one moves north and east through Pennsylvania, where the average is 1.82 percent sulfur. Of the coal deliveries with 1 percent or less sulfur, West Virginia supplies 80 percent of total utility coal receipts originating from the region. Of the utility coal originating from the region, with sulfur content greater than 1 percent through 3 percent, 49 percent comes from Pennsylvania, 37 percent from West Virginia, and 11 percent from Virginia.

Utility Overview

The region is also a major coal user. Utilities in the Mid-Atlantic Region account for 14 percent of U.S. utility coal consumption. And between 1990 and 2010 the region is projected to increase this demand by a total of 34 percent, while the U.S. demand is forecast to increase by almost 36 percent. Coal receipts by Mid-Atlantic utilities are composed of 24 percent containing 1 percent or less sulfur and 62 percent with over 1 percent up through 3 percent sulfur. West Virginia utilities account for 46 percent of coal receipts with the lowest sulfur content, while Pennsylvania utilities account for 59 percent of the higher ranges of sulfur content.

As shown in Table 1, there are 44,138 MWe of coal-fired generating capacity in the region, 14 percent of the total U.S. coal-fired capacity. There are 141 coal-fired units operated by 17 utility companies. There are utility-operated coal-fired units in all Region 3 states, except the District of Columbia. About 56 percent of the utility generating capacity in the region is coal-fired. In West Virginia, nearly 99 percent is coal-fired, while the other states range from 31 percent in Virginia to 53 percent in Pennsylvania.

Only 17 units are currently equipped with flue gas desulfurization (FGD) devices: 15 are located in Pennsylvania and 2 in West Virginia. Coals used by utilities in these two states have the highest (unweighted) average sulfur content.

The region's coal-fired capacity is aging, as shown in Table 2. The average age of a coal-fired unit is 31 years. On average, Virginia units are even older at 35 years. The utilities with the largest amount of capacity over 30 years old are Potomac Electric Power, Metropolitan Edison, Pennsylvania Power and Light, Philadelphia Electric, Virginia Power, and Appalachian Power.

Although reserve margins are generally satisfactory across the region, several utilities report margins that are already very low: Delmarva Power & Light, 9 percent; Potomac Electric

Table 1
Existing Coal-Fired Units in 1990

State	No. of Utilities*	No. of Units	Nameplate Capacity of Coal-Fired Units (MWe)	% of Capacity Coal Fired
Delaware	1	5	959.2	45
Maryland	3	14	4,257.4	40
Pennsylvania	8	65	19,414.7	53
Virginia	3	24	4,548.9	31
W. Virginia	5	33	14,957.4	99
Region 3	17	141	44,137.6	56

State	Units with FGD	Coal Use (10 ³ Tons/Yr)	Ave. % Sulfur Content**
Delaware	0	2,192	0.93
Maryland	0	10,001	1.39
Pennsylvania	15	44,796	1.86
Virginia	0	8,488	0.96
W. Virginia	2	33,092	1.76
Region 3	17	98,569	1.38

* Number of utilities operating coal-fired units in state. The total of 17 is adjusted to count each utility only once. Appalachian Power operates coal-fired units in Virginia and West Virginia. Virginia Power operates units in Virginia and West Virginia. Potomac Electric Power operates coal-fired units in Maryland and Virginia.

** Unweighted average sulfur content in 1990.

Table 2
Aging of Existing Coal-Fired Units

State	Ave. Age of Coal-Fired Units in 1992	Units Age 30+		Capacity Age 30+	
		No.	%	MWe	%
Delaware	26	2	40	163.2	17
Maryland	29	8	57	1,233.3	29
Pennsylvania	34	45	69	5,347.2	28
Virginia	35	22	92	3,496.0	77
W. Virginia	30	16	48	2,857.8	19
Region 3	31	93	66	13,097.5	30

Power, 9 percent; and Pennsylvania Electric, 6 percent. Moreover, even with conservation and improved efficiency, total electricity demand in the Mid-Atlantic Region is projected to grow over the next two decades. Unless electricity supplies can be increased, reserve margins in this region could fall to levels that would impair the reliability of service.

The integrated resource plans developed by a number of utilities identify a number of supply-side options. (See Appendix B for a synopsis of integrated resource planning.) However, only two of these options, repowering and adding baseload generating capacity, offer potential markets for CCTs.

Repowering Markets for CCTs

Typically, coal-fired generating units have an operating life of 30-40 years; however, rehabilitation, maintenance, and life extension measures can prolong operating life to about 50 years or more. These measures are typically among the least-cost supply options available to utilities for meeting load requirements. Therefore, expanded maintenance, life extension, and repowering programs can be expected to gain in importance in coming years.

Life extension and repowering offer many advantages over building new plants. Both options tend to be more cost effective and less risky than new plant construction and tend to involve fewer siting and permitting problems. Utility plans to retire and repower coal-fired units are summarized in Table 3.

Delmarva's 1993 integrated resource plan specifically addresses the issue of unit aging and its effect on supply decisions. Several years ago, Delmarva instituted a life-extension program in order to push the normal 30-year life of its units to 50 years. The company notes that if Indian River Units 1 and 2 are not repowered, they would be retired in 2008 and 2009; Edge Moor Unit 3 is scheduled for retirement in 2008. Delmarva plans to repower both Indian River Units 1 and 2 using circulating fluidized-bed boilers and is assessing the potential for repowering Edge Moor Unit 3; the utility indicates that it is evaluating repowering options that offer opportunities for reducing emissions levels.

Because of the siting and permitting problems that new facilities often encounter, it would be reasonable to expect utilities to continue to use existing power stations as long as possible, or to sell (or transfer) the assets to another power generator, possibly an independent power producer. So although there is considerable uncertainty about the future of aging coal-fired units, they probably represent a very significant repowering market for CCTs—to the extent that CCTs are competitive with gas-fired and other technologies suitable for repowering applications.

CCT Markets in New Capacity Additions

Most of the utilities plan to maintain or increase their reserve margins, particularly by adding gas-fired combustion turbines and combined-cycle units to satisfy peak and intermediate load conditions. These new units are, in part, the reason why natural gas use for power generation

Table 3
Planned Retirement and Repowering of Coal-Fired Units

State	Utility	Plant/Unit	Capacity (MWe)	Date of Change	Comments	Ref.
Delaware	Delmarva Power & Light	Indian River Unit 2	-89	1998	Date unit to be taken out of service for repowering.	1
		Indian River Unit 1	-89	2000	Date unit to be taken out of service for repowering.	1
		Indian River Unit 2	+87	2001	To be repowered with circulating fluidized-bed boiler.	1
		Indian River Unit 1	+87	2003	To be repowered with circulating fluidized-bed boiler.	1
		Edge Moor Unit 3	-82	2008	Evaluating possible repowering of unit.	1
Pennsylvania	Metropolitan Edison Co.	Titus Units 1-3	-241	2010	To be retired.	2
		Portland Units 1-2	-427	2015	Considering repowering with combustion turbine.	2
	Pennsylvania Electric Co.	Warren Units 1 & 2	-88	2010	Two units scheduled to be retired in 2010; as CCT-V demonstration project, units would be repowered using externally fired gas turbine combined-cycle system.	3
		Seward Unit 4	-62	2010	To be retired	3
Virginia	Appalachian Power Co.	Glen Lyn Unit 5	-95	2000	To be retired.	4
Net Change			-999			

References:

- 1 Delmarva, Integrated Resource Planning Study: Demand and Supply-Side Plan Update, June 1993.
- 2 Metropolitan Edison Company, Annual Resource Planning Report, May 1993.
- 3 Pennsylvania Electric Company, Annual Resource Planning Report, 1993.
- 4 North American Electric Reliability Council, Electric Supply and Demand 1993-2002, June 1993, pp. 95-118.
(EIA's Inventory of Power Plants of the United States 1991 lists no planned retirements for this region.)

is projected to grow by 468 percent between 1990 and 2010. Over the same period, coal use by utilities is expected to increase by 34 percent.

Between now and the year 2000, most planned capacity additions, whether by utilities or independent power producers, appear to be gas- and oil-fired combustion turbines and combined cycles. Relatively few of the new coal-fired capacity additions are planned for this period. Most of the coal-fired capacity additions in this region are scheduled to come on line after 2000. Metropolitan Edison's integrated resource plan offers the following explanation for this trend:

... for capacity entering service in the mid-1990s, the combustion turbine is the most economic choice for capacity factors up to 10% (peaking), while the combined cycle is the most economic option for capacity factors from 10 to 80% (bulk power). However, for the capacity entering service in the year 2000, coal capacity becomes the preferred source of bulk power for capacity factors of 70% or higher. A 70% capacity factor represents a reasonable operational level for either coal or combined cycle and reflects the economic "break-even point" between the options for a 2000 in-service date. For planning purposes, we have selected coal technology as the bulk power option of choice for in-service dates of 2000 and later, not only due to its relative economics vis a vis combined cycle but also due to concerns over the cost and availability of future gas supplies in the early 2000s.

Nevertheless, several utilities have indicated plans to add new coal-fired capacity in the Mid-Atlantic Region during the 1990s and beyond. These planned coal-fired capacity additions total nearly 8 GWe and consist of 31 units. Table 4 indicates the sizes of the planned coal-fired units and the time period during which the units are expected to come on line. Half of the planned additions are under 300 MWe and half are 300 MWe or larger; the largest planned units, Clover 1 and 2, are 424 MWe (nameplate capacity). Nearly all coal-fired units planned to come on line before the year 2000 are under 300 MWe.

Figure 1 shows cumulative coal-fired capacity additions planned by utilities and nonutility generators through 2012. Virginia units account for the largest share of the planned capacity.

Table 4
Size and Timing of Coal-Fired Capacity Additions

Time Period	Planned Coal-Fired Units*	Unit Sizes		
		0-299 MWe	300-499 MWe	500+ MWe
1993-1999	15	13	2	0
2000-2005	7	1	6	0
2006-2012	8	0	8	0
Total	30	14	16	0

* The in-service date is not available for one addition of 14 MWe.

Figure 1

Easton Utilities (MD) plans to add 14 MWe in a CCT demonstration project. On-line date is to be determined.

Table 5 lists the new coal-fired additions planned by each utility in the region. Many planned additions are undesignated or unsited units. To some extent these units serve as "place holders" to indicate anticipated baseload requirements. As the time draws near for the utility to make more definitive decisions, the "build (or repower) versus buy" decision will be reconsidered, as will be the choice of fuel and technology.

Utilities planning to add new baseload capacity reported that they reviewed a range of technology options for these units. Following is a composite list of conventional and advanced coal technologies considered:

- Conventional pulverized coal with FGD (wet and dry)
- Atmospheric fluidized bed combustion - circulating and bubbling
- Conventional pulverized coal with physical coal cleaning and with chemical/biological coal cleaning
- Integrated gasification combined cycle

In addition, utilities noted that they were monitoring the development of several advanced technologies:

- Pressurized fluidized-bed combustion
- Electric Power Research Institute's state-of-the-art power plant
- Advanced fuel cells with coal gasification
- Supercritical pulverized coal

Some of the region's coal-fired capacity additions are contingent on successful completion of the transmission lines. In Pennsylvania, Duquesne plans to recommission the Phillips Station now in cold reserve and to sell half of the plant's capacity to the General Public Utilities system. In Virginia, a transmission line is needed for a CCT demonstration project - a new PFBC unit at Mountaineer, a West Virginia project planned by Appalachian Power. Also, if the transmission line is built, Virginia Power plans long-term power purchases from AEP's excess capacity as part of its long-term supply-side strategy. However, there has been local opposition to both of the planned high-voltage lines, with residents expressing concerns about electromagnetic fields and other siting impacts.

Construction of new transmission lines is a major issue in Virginia and Pennsylvania. Two projects to construct new high-voltage transmission lines are proposed in the region - both would be west-to-east interconnections. One project involves a 765-kv, 112-mile line proposed by Appalachian Power (American Electric Power) and Virginia Power between southern West Virginia and southwestern Virginia, and a 500-kv, 100-mile interconnection between the two systems, running from Lynchburg to Richmond, Virginia. The other project is a 500-kv, 268-mile line proposed by Duquesne Light and General Public Utilities to run between Pittsburgh and Harrisburg, Pennsylvania. This Pennsylvania line would address what Duquesne calls "one of the biggest bottlenecks" in the national transmission grid.

Table 5
Coal-Fired Capacity Additions Planned

State	Utility	Plant Unit	Capacity (MW)	Start Date	Comments	Ref.
Delaware	Delmarva Power & Light	Undesignated	300	2006	Utility-owned pulverized coal with dry scrubber.	2
		Undesignated	300	2009	Utility-owned pulverized coal with dry scrubber	2
Maryland	Baltimore Gas & Electric	Undesignated	214	2004		12
	Delmarva Power & Light	Dorchester Unit 1	300	2000	Utility-owned pulverized coal with dry scrubber, near Vienna, MD (Eastern Shore).	2, 3, 8, 9
	Easton Utilities	Easton Unit 2	14		CCT demonstration project; two stationary diesel engine power systems using coal-water slurry	10
Pennsylvania	Potomac Edison Co.	AES Cumberland	180	1999	PURPA unit owned by AES, Inc.	1
	Allegheny Power Systems	PURPA 1	130	1995	PURPA unit.	8
	General Public Util. Corp.	Logan Energy	200	1994	NUG unit.	8
		Coal 1	200	2000		8
	Metropolitan Edison Co.	York County	227	1997	NUG--York County Energy Partners; CCT demo. project. CFB.	5, 8, 11
	Pennsylvania Electric Co.	Scrubgrass Power	80	1993	NUG unit under construction in Venango County; power purchase contract signed.	6, 7
Virginia	Virginia Power Co.	Interpower	102	1995	NUG unit in Cambria County; power purchase contract signed; not yet under construction.	6, 7
		Homer City Modular	18	1995	NUG unit in Indiana County; power purchase contract signed; not yet under construction.	6, 7
		Northampton	89	1995	NUG waste coal unit in North Hampton County; power purchase contract signed; not yet under construction.	6, 7
		Gen. Co.				
		Scranton Energy	100	1996	NUG waste coal unit in Lackawanna County; power purchase contract signed; not yet under construction.	6, 7
		Undesignated	400	2002		4
		Undesignated	400	2003		4
		Undesignated	400	2005		4
		Undesignated	400	2006		4
		Undesignated	400	2007		4
		Undesignated	400	2008		4
		Undesignated	400	2009		4
		Undesignated	400	2011		4
		Undesignated	400	2012		4
	Commonwealth SEI Birchwood	Commonwealth	112	1993	NUG--Commonwealth Cogeneration.	8
		SEI Birchwood	198	1996	NUG--SEI.	8
		Toms Creek	107	1996	NUG--TAMCO; CCT demonstration project, IGCC.	11

Table 5
Coal-Fired Capacity Additions Planned

State	Utility	Plant/Unit	Capacity (MWe)	Start Date	Comments	Ref.
	Virginia Power & Old Dominion Elec. Coop.	Clover Unit 1	424	1995		4, 7, 9
		Clover Unit 2	424	1996		4, 7, 9
W. Virginia	Appalachian Power Co.	Mountaineer	340	2002	CCT demonstration project, PFBC.	8, 11
	Monongahela Power Co.	Grant Town	80	1993	PURPA unit.	1
Total			7,939			

NUG stands for nonutility generator and includes PURPA cogenerators and independent power producers.

PURPA is the Public Utility Regulatory Policies Act of 1972.

CFB=circulating fluidized bed; PFBC=pressurized fluidized-bed combustion; IGCC=integrated gasification combined cycle.

References:

- 1 Allegheny Power System, Integrated Resource Plans for Monongahela Power Company, The Potomac Edison Company, West Penn Power Company, and combined Integrated Resource Plan for Allegheny Power System, April 1993. (Plans through 2003.)
- 2 Delmarva, Integrated Resource Planning Study: Demand and Supply-Side Plan Update, June 1993.
- 3 Delmarva Power Company, 1992 Annual Report.
- 4 Virginia Power Company/North Carolina Power Company, Long-Range Forecast of Load and Resources 1993-1012. (Specific NUG not identified.)
- 5 Metropolitan Edison Company, Annual Resource Planning Report, May 1993.
- 6 Pennsylvania Electric Company, Annual Resource Planning Report, 1993.
- 7 North American Electric Reliability Council, Electric Supply and Demand 1993-2002, June 1993, pp. 95-118.
- 8 R. Smock, "Utilities expand baseload power plant plans," Power Engineering, April 1993.
- 9 Energy Information Administration, Inventory of Power Plants in the United States 1991, DOE/EIA-0095(91), October 1992.
- 10 Clean Coal Technology Demonstration Program, Clean Coal Today, DOE/FE-0215P-9, Issue No. 10, Spring 1993.
- 11 Clean Coal Technology Demonstration Program, Program Update 1992, DOE/FE-0272, U.S. Department of Energy, February 1993.
- 12 Baltimore Gas & Electric Co., Integrated Resource Plan 1991-2005, June 1991.

CAAA Compliance Strategies

Title IV of the CAAA of 1990 requires that emissions from coal-fired power plants be reduced in two phases. Utility units larger than 75 MWe that emitted SO₂ at a rate greater than 2.5 pounds per million Btu in 1985 are defined as affected units in Phase I and must meet the emission limits established beginning in 1995. Under Phase I, affected units are required to reduce SO₂ emissions by a predetermined amount no later than 1995. In addition, utilities must install emissions monitoring equipment and low-NO_x burners in affected units. Phase II affects all existing utility units and all new utility units with an output capacity greater than 25 MWe. Under Phase II, SO₂ emissions are subject to a cap of 1.20 pounds per million Btu, beginning January 1, 2000.

The SO₂ reduction requirements of Title IV are to be implemented by means of a market-based approach utilizing marketable emission "allowances" (also called credits). Each allowance permits a utility to emit one ton of SO₂ from affected generating units during or after the year specified on the allowance. Title IV provides for a finite number of allowances to be allocated by the U.S. Environmental Protection Agency (EPA) pursuant to statutory and regulatory guidelines, so that the total supply of allowances is limited. Each affected utility unit which was in operation prior to the CAAA will be allocated a specific number of allowances annually, based on its historic fuel consumption and a specific emission rate. The utility must give EPA allowances equal to the total annual SO₂ emissions from its affected units during a particular calendar year, within 30 days after the end of that year—or be subject to severe civil and criminal penalties.

The CAAA includes several options designed to provide flexibility in meeting SO₂ emission reduction requirements. Utilities may take advantage of these options by requesting EPA approval. Some options offer opportunities for utilities to acquire additional allowances from EPA's various "reserves" created by Title IV.

Options include the following:

- **Phase I Extension**—A utility owning a Phase I unit may apply to EPA for a 2-year extension of the Phase I SO₂ and NO_x emissions limits. Extensions are only granted for units for which the utility commits to install a "qualifying Phase I technology" (i.e., it achieves 90 percent reduction in SO₂, such as a scrubber or advanced FGD) before 1997, or for those units that rely on reduced emissions at another unit which commits to installing a qualifying Phase I technology. A unit where this technology is being installed is known as a control unit; a unit which relies on the reduced emissions at a control unit is known as a transfer unit. Each unit receiving the extension (including both control and transfer units) will be given additional allowances above its statutory allocations of basic allowances to cover emissions during the extension period. CAAA makes available only 3.5 million allowances for extension plans. (These credits were allocated on May 31, 1993.)
- **Reduced Utilization**—A utility may meet the emission reduction requirements for an affected Phase I unit by reducing generation at the unit. The utility can compensate for planned reduced output at a particular unit by the following methods: (1)

designating a non-Phase I unit or units to increase generation (such units are referred to as compensating units), (2) adopting verifiable energy conservation or improved efficiency measures at the unit, or (3) designating "sulfur-free generation" (e.g., nuclear generation) to compensate for the unit's reduced output. EPA will grant allowances to utilities for compensating units based on their 1985 emission rate and their baseline heat input. The utility must hold allowances to cover annual SO₂ emissions of both the original and compensating units. Unplanned reductions in utilization below the 1985-1987 average (baseline) for the dispatch system require that the owner surrender allowances in accordance with specified procedures.

- **Unit Substitution**—A utility can substitute emission reductions at a Phase II unit for the emission reductions required for a Phase I unit. The Phase II unit, known as the substitution unit, consequently becomes a Phase I affected unit, is allocated allowances based on its 1985-1987 average heat input and the lesser of its actual or allowable 1985 emission rate, and must meet the Phase I SO₂ requirements.
- **Energy Conservation and Renewable Energy Reserve**—A utility may apply to EPA for allowances for using qualifying energy conservation measures or qualifying renewable energy to avoid SO₂ emissions at an affected unit. A qualifying energy conservation measure is a cost-effective measure that increases the efficiency of the use of electricity provided by an electric utility to its customers. Renewable energy is derived from biomass, solar, geothermal, or wind. Utilities must have implemented a least-cost plan (or integrated resource plan) that has been approved by the public utility commission, and the measures must be consistent with that plan. The CAAA makes available 300,000 allowances for this reserve which EPA is to allocate on a first-come, first-served basis, beginning on January 1, 1995, according to a predetermined formula applied to kilowatt hours saved by energy conservation measures or generated from renewable energy sources.
- **Emission Allowance Auctions**—The CAAA provides for a certain portion of the total allowances to be held in reserve by EPA and requires EPA to sell these allowances in yearly "spot" and "advance" auctions beginning in 1993. (The Chicago Board of Trade is handling these auctions.) Allowances sold in spot auctions are usable for purposes of compliance in the year in which they are sold and at any time thereafter, except that allowances sold in 1993 and 1994 are not usable until 1995. Allowances sold in advance auctions are Phase II allowances and are usable beginning 7 years from the year of purchase. These allowances are sold by sealed bid to the highest bidder; EPA does not set a minimum price for these allowances. Immediately after EPA's allowances are sold, credits offered by other parties (e.g., utilities, brokers, and private parties) are auctioned, also by sealed bid. Unlike EPA, other parties may set a minimum acceptable price on their credits offered for auctioning. Allowances are sold beginning with those offered at the lowest minimum price set by the seller. (The Chicago Board of Trade held its first auction of credits on March 29, 1993.)

CAAA recognizes repowering as an important SO₂ compliance option during Phase II, and the statute allows utilities to apply for a repowering extension for affected Phase II units. A

repowering extension, which may not go beyond December 31, 2003, provides a qualifying utility with extra allowances to cover its emissions while installing a qualifying repowering technology (i.e., CCTs). These allowances may only be transferred among units at the same source. This compliance option also applies under certain circumstances to a new unit which uses a repowering technology and replaces an existing utility unit.

The Mid-Atlantic Region has 41 units that are affected by Phase I, as shown in Table 6. These units make up 29 percent of all coal-fired units in the region. Phase I units are located in only three states: 21 are in Pennsylvania, 14 in West Virginia, and 6 units in Maryland. Nameplate capacity affected by Phase I totals 17,428 MWe, or 39 percent of the region's coal-fired capacity. The Phase I units in the region are operated by 10 different utilities.

Table 6
Summary of Phase I Affected Units

State	Phase I Units	% of Coal-Fired Units	Phase I Capacity (MWe)	% of Coal-Fired MWe	Utilities Affected
Delaware	0	0	0	0	0
Maryland	6	43	2,379.8	56	2
Pennsylvania	21	32	7,696.2	40	5
Virginia	0	0	0	0	0
W. Virginia	14	58	7,351.8	49	3
Region 3	41	29	17,427.8	39	10

Table 7 lists the strategy planned for Phase I units in the region. Switching to lower sulfur coals is the most prevalent SO₂ compliance strategy being adopted for Phase I. A total of six units will get scrubbers. Two units are being modified to cofire or seasonally fire natural gas as a means of reducing SO₂ emissions.

Utilities have filed with state commissions for cost recovery. All the region's states except Pennsylvania are allowing a surcharge on current rates. However, in Pennsylvania, the public utility commission ruled that a surcharge is not legal and that the utilities will have to file for a new base rate that incorporates these cleanup costs. Whether rate proceedings will present any significant barrier to Phase I implementation remains to be seen, but there could be major implications for Phase I and II implementation strategies, as rate proceedings can be lengthy and controversial. Moreover, at the time this study was conducted, the Pennsylvania legislature was considering legislation that could prohibit a utility from switching fuels as part of its CAAA compliance strategy if the fuel switching would result in significant local or regional economic disruption or unemployment.

The strategies that utilities ultimately implement for Phase II depend partly on the physical characteristics of the units and the situation at each plant. Phase I decisions may also affect

Table 7
CAAA Phase I Strategies

Utility	Plant	Nameplate		Start Year	Age in 1992	Phase I Allowances	Phase I Sulfur Dioxide Strategy
		Unit	Capacity (MWe)				
MARYLAND							
Potomac Electric Power Co.	Chalk Point	1	364.0	1964	28	21,910	Cofire/seasonally fire with natural gas at both units.
		2	364.0	1965	27	24,330	
	Morgantown	1	626.0	1970	22	35,260	Switch both units from 1.68% sulfur to lower sulfur coal.
		2	626.0	1971	21	38,480	
Baltimore Gas & Electric Co.	CP Crane	1	190.4	1961	31	10,330	Switch both units from 2.17% sulfur to lower sulfur coal.
		2	209.4	1962	30	9,230	
Total Maryland	3	6	2,379.8	1966	27	139,540	
PENNSYLVANIA							
Duquesne Light Co.	Cheswick	1	587.0	1970	22	39,170	Already meets Phase I limits.
Metropolitan Edison Co.	Portland	1	171.7	1958	34	5,940	Switch both units from 1.93% sulfur to lower sulfur coal.
		2	255.0	1962	30	10,230	
Pennsylvania Electric Co.	Conemaugh	1	936.0	1970	22	59,790	Scrub both units by 1995.
		2	936.0	1971	21	66,450	
	Shawville	1	125.0	1954	38	10,320	Switch station from 1.93% sulfur to lower sulfur Pennsylvania coal.
		2	125.0	1954	38	10,320	
		3	187.5	1959	33	14,220	
		4	187.5	1960	32	14,070	
Pennsylvania Power & Light Co.	Brunner Island	1	363.3	1961	31	27,760	Switch units from 1.95% sulfur to lower sulfur coal.
		2	405.0	1965	27	31,100	
		3	790.4	1968	24	58,820	
	Martin's Creek	1	156.3	1954	38	12,660	Switch both units from 1.95% sulfur to lower sulfur coal.
		2	156.3	1956	36	12,820	
	Sunbury	3	103.5	1951	41	8,760	Switch both units 1.54% sulfur to lower sulfur coal.
		4	156.3	1953	39	11,450	
West Penn Power Co.	Armstrong	1	163.2	1958	34	14,410	(Information not available)
		2	163.2	1959	33	15,430	
	Hatfields Ferry	1	576.0	1969	23	37,830	(Information not available)
		2	576.0	1970	22	37,820	
		3	576.0	1971	21	40,270	
Total Pennsylvania	9	21	7,696.2	1963	30	539,640	

Table 7

CAAA Phase I Strategies

Utility	Plant	Unit	Nameplate Capacity (MWe)	Start Year	Age in 1992	Phase I Allowances	Phase I Sulfur Dioxide Strategy
WEST VIRGINIA							
Monongahela Power Co.	Albright Fort Martin	3	140.3	1954	38	12,000	(No change reported)
		1	576.0	1957	35	41,590	Switch both units from 1.83% sulfur to lower sulfur coal.
	Harrison	2	576.0	1968	24	41,200	
Ohio Power Co.	Kammer	1	684.0	1972	20	48,620	Switch all 3 units from 4.26% sulfur to medium-sulfur coal.
		2	684.0	1973	19	46,150	
		3	684.0	1974	18	41,500	
Virginia Power Co.	Mt. Storm	1	237.5	1958	34	18,740	(No change reported)
		2	237.5	1958	34	19,460	
		3	237.5	1959	33	17,390	
Total West Virginia	Region 3	6	7,352.8	1966	26	497,870	Scrub by 1995.
Notes:	The phrase "lower sulfur" coal refers to a coal with a lower sulfur content than the currently used coal. This does not necessarily mean that the units are being switched to "low-sulfur" coal, which has a sulfur content of about 1% or less. (See Appendix A for plant's coal quality.)	Sources:	DOE/EIA, Inventory of Power Plants in the United States 1990, Table 20, October 1992. Clean Air Act Amendments of 1990, Public Law 101-549, November 15, 1990, Table A, Title IV. Strategies are from CAAA compliance plans, integrated resource plans, annual reports, and the news media.	An allowance is one ton of sulfur dioxide that may be emitted from an affected source over the course of a year.			

Notes: An allowance is one ton of sulfur dioxide that may be emitted from an affected source over the course of a year.

The phrase "lower sulfur" coal refers to a coal with a lower sulfur content than the currently used coal. This does not necessarily mean that the units are being switched to "low-sulfur" coal, which has a sulfur content of about 1% or less. (See Appendix A for plant's coal quality.)

Sources: DOE/EIA, Inventory of Power Plants in the United States 1990, Table 20, October 1992.

Clean Air Act Amendments of 1990, Public Law 101-549, November 15, 1990, Table A, Title IV.

Strategies are from CAAA compliance plans, integrated resource plans, annual reports, and the news media.

Phase II strategies. Further, there are special environmental requirements at certain locations that may override most other considerations in determining final CAAA strategies. Of particular importance are ozone and SO₂ nonattainment areas as well as Class I regions. In addition, options for existing units may be more limited, due to space constraints, for example, than for new units where there is greater design flexibility.

Phase II compliance strategies being considered include the following:

- Option 1—Installing SO₂ and NO_x emissions reduction equipment (scrubbers or advanced CCTs) on affected units.
 - Allows continued use of higher sulfur coal.
 - Requires substantial capital expenditures, increased operating costs, and reduced generation efficiency.
- Option 2—Switching to lower sulfur coal or natural gas, or blend lower- and higher-sulfur fuels.
 - Results in adverse impacts on affiliated mining operations and related facilities.
 - May have significant socioeconomic impacts by depressing the local coal industry.
 - Less substantial capital expenditures than Option 1.
- Option 3—Prematurely retiring certain units.
- Option 4—Using emissions allowances.
 - Purchase emissions allowances from unaffiliated utilities or other emitters, or through bidding at auctions.
 - Over comply at certain affected units and use allowances as offsets for other affected units.
 - Bank excess Phase I allowances and apply these in Phase II as offsets for other affected units, or sell allowances to other utilities.

An additional option mentioned by a few utilities is greater emphasis on demand-side programs to conserve energy and improve energy efficiency. This option is seen as a means of reducing total generation capacity requirements and thus the amount of SO₂ and NO_x emissions that otherwise would be produced.

The following utilities are considering advanced CCTs, in addition to the other options:

- Delmarva—As the utility's existing units age, older units will gradually be replaced with newer, cleaner units.
- Baltimore Gas & Electric—The utility is considering FGD control technology and sorbent injection for existing units and CCTs for future additions.
- Pennsylvania Electric—The company plans to scrub Homer City Unit 3 and switch to lower sulfur coal at Seward and Warren Stations. Homer City Units 1 and 2 will use existing coal-cleaning technology.

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- Potomac Electric Power—The utility will reexamine SO₂ removal technologies as regulations and economics dictate.
 - Duquesne—The company is exploring a combination of compliance methods, including advances in CCTs in addition to lower sulfur coal, increased use and enhancement of scrubbed capacity, and allowance trading.
 - General Public Utilities—The parent of Pennsylvania Electric and Metropolitan Edison is keeping options open and reviewing alternatives.
 - Virginia Power—Mt. Storm Unit 3 will be scrubbed by January 1, 1995. Scrubbers are also planned for Mt. Storm Units 1 by July 1999 and Mt. Storm Unit 2 by July 1998. The company will continue to evaluate possible lower cost alternatives for Phase II, such as allowances or possibly some other newer technology. (The company considered selective catalytic reduction for NO_x control at Clover but found it was not the least-cost option for the plant.) All in-system coal-fired units will burn lower sulfur coal beginning in 2006. The utility also plans to install FGD equipment on Chesterfield Units 3 and 6, Possum Point Unit 3, and Yorktown Unit 1.
 - Ohio Power—The company is considering a combination of alternatives including acquiring emissions allowances and allowance pooling agreements with non-affiliated utilities.

An innovative feature of the CAAA of 1990 is its provisions for the use and transfer of emissions allowances. At present, allowances are available only for SO₂ emissions. In general, one allowance (or credit) permits its holder to emit one ton of SO₂ over the course of a year. Consequently, if a utility is able to obtain allowances for less than it would cost to install FGD or change the fuel, then the utility could choose to offset the emissions with allowances.

Several market mechanisms have evolved for the trading of emissions allowances, including the following:

- Private sales, such as the late-1991 agreement between Duquesne Light and Wisconsin Power & Light in which Duquesne agreed to buy an undisclosed number of allowances directly from the Wisconsin utility for \$250-350 per credit.
 - Annual public auctions of allowances offered by EPA, such as the March 29, 1993, auctions administered by the Chicago Board of Trade (CBOT)—a spot auction of 50,000 Phase I credits (which can be used any time after January 1, 1995) and an advance auction of 100,000 Phase II credits (which can be used any time after January 1, 2000).
 - Periodic private auctions of allowances conducted by CBOT, such as the two held in conjunction with the March 29, 1993, auctions of EPA credits (95,010 Phase I credits and 30,500 Phase II credits were offered by utilities; only 10 Phase I credits sold).
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- Lottery held by EPA May 31, 1993, to allocate 3.5 million credits for Phase I extension applications.
 - Direct sale of allowances by EPA beginning June 1, 1993, for a fixed price of \$1,500 apiece, adjusted yearly for inflation, and available on a first-come, first-served basis until none are left.

No Region 3 utility successfully bid at the March 29, 1993, spot and advance auctions administered by CBOT.

On May 31, 1993, EPA held a lottery to allocate, 3.5 million credits to utilities that had applied for an extension of up to 2 years for meeting Phase I requirements because the utility is employing a qualifying Phase I technology (e.g., scrubber or CCT). Seventeen applications sought over 4 million credits, more than the total available. At the lottery session, EPA drew numbers assigned to each application and established a rank for each. Following the drawing, EPA sequentially awarded credits, according to lottery rank, until no credits remained to be allocated. A "winner" (i.e., a high ranking application) got all the credits it was eligible to receive, except that the last winner received only part of the credits applied for, and a "loser" (i.e., a low ranking application) got none. Table 8 lists the results of EPA's lottery for Phase I extension credits. (The actual award is contingent on a substantive EPA review of each application and issuance of an acid rain permit.)

Prior to the lottery, all but one of the applicants agreed among themselves to pool whatever credits they won through the lottery and then to reallocate these credits among pool members on a *pro rata* basis. By promising to share their credits, all pool members were guaranteed to receive most of the credits for which they had applied, and none risked losing out altogether. Pool members who were "winners" get 87-88 percent of the credits they qualify for. Those pool members who were "losers" get 82-83 percent. This distribution formula compensates the "winners" for the expense and effort of their reporting requirements with EPA. The only applicant not joining the pool was Potomac Electric Power Company who had applied for 21,240 credits for cofiring and seasonally using gas at Chalk Point 2; this utility was a lottery "winner." The remaining 3,478,760 credits are being divided among the pool members for their Phase I extension applications.

Four of the applications for Phase I extension credits were for units located in Region 3. Region 3 utilities applying for Phase I unit extension credits follow:

- Pennsylvania Electric applied for 479,130 credits to scrub Conemaugh Units 1-2.
- Potomac Electric Power applied for 21,240 credits to install gas cofiring or seasonal gas firing at Chalk Point 2; in July 1993, EPA determined that this project qualified for extension credits. (This was the only utility that did not join the pool.)
- Allegheny Power Systems applied for 655,421 credits to scrub Harrison 1-3.
- Virginia Power applied for 137,569 credits to scrub Mt. Storm Unit 3.

Table 8
Results of EPA Lottery to Allocate Phase I Extension Credits

EPA Lottery Rank	Utility Company	Name of Controlled Source	Control Technology	State	No. of		Credits EPA Awarded
					Allowances Requested	Awarded	
1	Kentucky Utilities	Ghent 1	Scrubber	KY	128,493	128,493	
2	PSI Energy	Wabash River	IGCC repowering*	IN	13,251	13,251	
3	Tennessee Valley Authority	Cumberland 1&2	Scrubber	TN	807,217	807,217	
4	Northern Indiana Public Service	Bailey 7&8	Scrubber	IN	152,355	152,355	
5	Pennsylvania Electric	Conemaugh 1&2	Scrubber	PA	479,130	479,130	
6	Georgia Power	Yates 1	CT-121 FGD*	GA	21,267	21,267	
7	Atlantic Electric	BL England 2	Scrubber	NJ	44,016	44,016	
8	Potomac Electric Power Company	Chalk Point 2	Gas cofiring or seasonal firing	MD	21,240	21,240	
9	American Electric Power	Gen. JM Gavin 1&2	Scrubber	OH	855,172	855,172	
10	Allegheny Power System	Harrison 1-3	Scrubber	WV	655,421	655,421	
11	Virginia Power	Mt. Storm 3	Scrubber	WV	137,569	137,569	
12	Big Rivers Electric Corporation (owned by Henderson Municipal Power & Light)	HMP&L (Henderson) Station Two 1&2	Scrubber	KY	98,890	98,890	
13	PSI Energy	Gibson 4	Scrubber	IN	158,754	85,979	
14	New York State Electric & Gas	Milliken 1&2	Advanced FGD*	NY	70,455	0	
15	Indianapolis Power & Light	Petersburg 1&2	Scrubber	IN	177,423	0	
16	Owensboro Municipal Utilities	Elmer Smith 1&2	Scrubber	KY	89,892	0	
17	Southern Indiana Gas & Electric	FB Culley 2&3	Scrubber	IN	106,691	0	
Total					4,017,236	3,500,000	

* CCTI demonstration projects.

Sources: U.S. EPA Acid Rain Division, "Phase I Extension Application Ranking Lottery Report and Certification," March 31, 1993.
Table of Phase I extension applications to be ranked, provided by U.S. EPA Acid Rain Division.

In conclusion, while a few utilities are installing FGD devices to comply with Phase I SO₂ limits, most are pursuing strategies that defer major plant modifications until after Phase II begins. Utilities are taking advantage of the allowance transfer and trading features of the CAAA of 1990, sometimes in creative and innovative ways. The use of credits, during both Phases I and II, may serve to lengthen the "window of opportunity" for CCTs. This compliance approach allows time for the development of CCTs to advance to the point where they can become mature, reliable technologies and be perceived by utilities as effective Phase II options. Utilities also will be able to acquire valuable knowledge about the performance of emerging CCTs.

Important Environmental Factors

Although the region's air quality is generally good, there are a few exceptions. In certain urban areas, ozone levels are high. In two Pennsylvania locations, nonattainment of SO₂ is a possibility. Moreover, the region has numerous environmentally sensitive areas, including the Shenandoah National Park, the James River Face Wilderness, and the Chesapeake Bay. Major historically and culturally significant areas are densely distributed through the region's states. These environmental factors will influence the power generation markets for CCTs.

Nonattainment of National Ambient Air Quality Standards (NAAQS), particularly SO₂ and ozone standards, is a problem in the region. Two Pennsylvania power plants—Martin's Creek and Conemaugh—are located in areas which may not be attaining SO₂ standards:

- EPA has designated parts of Warren County, Pennsylvania, as SO₂ nonattainment areas. Further, New Jersey claims it is experiencing SO₂ impacts from Pennsylvania Power & Light Company's Martin's Creek plant. Regulatory action is being withheld, however, until EPA, Pennsylvania Power & Light, and the Pennsylvania and New Jersey environmental offices agree on and apply computer modeling to predict more accurately the actual ambient air quality of the area. The study area is also being expanded to include any predicted "area of concern" in the vicinity of the plant.
- EPA and the Pennsylvania Department of Environmental Resources have questioned attainment of SO₂ standards in the vicinity of the Chestnut Ridge Energy Complex. Pennsylvania Electric Company's Conemaugh Station is located at the complex. Air quality monitoring and modeling began in 1990 to determine if NAAQS is being attained. If not, significant SO₂ reduction beyond levels required by the CAAA of 1990 may be required at the Keystone-Conemaugh plants.

A northeast Ozone Transport Commission (OTC) was created by Title I of the CAAA of 1990 to address region-wide transport of ozone and precursor gases (particularly volatile organic compounds and NO_x) and to recommend to EPA measures necessary to ensure that states attain and maintain compliance with NAAQS for ozone in the northeastern United States. OTC member states in Region 3 are Delaware, the District of Columbia, Maryland, Pennsylvania, and Virginia. (West Virginia had not yet joined OTC when this study was conducted.)

There is the potential for states and the EPA to implement measures which may force much earlier installation of emissions controls than otherwise would be required under CAAA Phase II. Were this to happen, it could significantly narrow the window of opportunity for advanced CCTs.

Of the environmentally sensitive areas located in the Mid-Atlantic Region, the following three are especially important:

- Shenandoah National Park
- James River Face Wilderness
- Chesapeake Bay

The first two have been designated by the EPA as Class I areas. The purpose of this designation is to "preserve, protect, and enhance the air quality in national parks, national wilderness areas . . . and other areas of special national or regional, natural, recreational, scenic or historic value." So while the Chesapeake Bay is not currently designated as a Class I region, the ever-increasing public and state governmental interest in restoring and protecting the Bay, as well as the high concentration of major historical sites nearby, might eventually lead to the Bay or some part of it being given this designation.

Prevention of Significant Deterioration (PSD) permits are required for power plants planned for a site in the vicinity of a Class I area. Emissions levels allowable in a Class I area are based on "entitlements." A maximum allowable level is determined for a Class I area, and the difference between current ambient air quality and the maximum allowable is called an entitlement. If emissions from the power plant exceeds the allowable limit, the increment must be offset by reducing emissions at some other source. Although relatively simple in theory, there is much debate over entitlements and offsets.

Environmentalists and others opposing new coal-fired plants are employing Class I designation as a basis for objecting to construction or operation of the plant. This situation recently occurred at the new Clover Plant that Virginia Power and Old Dominion are building in southern Virginia when opponents challenged the plant's permits based on issues pertaining to Class I entitlements.

The Southern Environmental Law Center (SELC) has attempted to block construction and operation of Clover, arguing that the plant would increase air pollution and visibility problems at the Shenandoah National Park and other national forests in Virginia. In an agreement with the National Park Service, the utilities will provide Class I offsets for Clover by installing a scrubber at Mt. Storm Unit 3. However, the SELC wants firm promises from Virginia Power to offset Clover's pollution and to install better controls at Clover and other plants.

The Class I designation is becoming the focus of a number of environmental groups as a means of appealing permits. Continuing problems and controversy relating to this issue can be expected at other affected areas in Virginia, the region, and the nation.

Conclusions

In conclusion, the Mid-Atlantic Region offers significant potential markets for CCTs that can be retrofitted to existing coal-fired units as well as those applicable to new facilities. The region's power generators are heavy coal users and 56 percent of the existing nameplate capacity is coal-fired. With only 17 of the region's existing 141 coal-fired units equipped with FGD devices, there is a sizeable potential retrofit market for high-performance pollution control devices as well as coal-processing technologies that produce clean fuels.

Existing coal-fired units located in the region average 31 years of age. Over the next two decades, unit retirement and repowering are likely to become increasingly important issues as the region's existing coal-fired units age. Because of the siting and permitting problems that new facilities encounter, existing units represent significant potential markets for CCTs involving advanced electric power generation systems suitable for repowering applications and high-performance pollution control devices suitable for retrofit applications.

New power plants also offer potential markets for CCTs, in particular, advanced electric power generation systems and high-performance pollution control devices. Utilities plan to bring on line 30 increments of additional capacity, totaling 8 GWe, by 2012. These capacity increments could be provided by utility or nonutility generators.

Utility CAAA compliance strategies may lengthen the window of opportunity for CCTs, as utilities are deferring installation of FGD systems by using SO₂ emission allowances and lower sulfur coals to meet Phase I emission limitations at many affected units. This approach allows time for the development of CCTs to advance to the point where they could become mature, reliable technologies and be perceived by utilities as effective Phase II options. During this time window, utilities also will be able to acquire valuable knowledge about the performance of emerging CCTs.

Meanwhile, however, the region's evolving markets for CCTs are being shaped by the increasing competitiveness of the utility sector. Current trends in the utility industry suggest that nonutility generators represent an important, growing potential market for CCTs. Furthermore, environmental factors, such as the presence of nonattainment and Class I areas, are expected to have an especially significant impact on future developments in this region's utility markets.

Appendix A

Coal-Fired Power Plants in the Mid-Atlantic Region

COAL-FIRED POWER PLANTS IN THE MID-ATLANTIC REGION

UTILITY	PLANT	UNIT	NAMEPLATE CAPACITY (MWe)	COAL START YEAR	AGE IN 1992	PHASE I UNIT	FGD INSTALLED	COAL USE (1,000 TONS)	BTU/LB	SULFUR (%)	ASH (%)	STATE OF ORIGIN
DELAWARE--1990												
Delmarva Power & Light Co.	Edge Moor	4	176.8	1966	26			566	13,318	0.85	7.78	VA, WV
	Indian River	1	81.6	1957	35			1,626	12,936	1.01	9.03	KY, MD, PA
		2	81.6	1958	34							VA, WV
		3	176.8	1970	22							
		4	442.4	1980	12							
Total Delaware	2	5	959.2	1966	26	0	0	2,192	13,127	0.93	8.41	
MARYLAND--1990												
Baltimore Gas & Electric Co.	Brandon Shores	1	685.1	1984	8			1,862	12,740	0.70	9.43	KY, VA, WV
	C P Crane	1	190.4	1961	31	Yes		740	13,287	2.17	9.66	OH, PA, WV
		2	209.4	1962	30	Yes						
	Herbert A Wagner	2	136.0	1958	34			930	13,009	0.84	8.29	KY, WV
		3	359.0	1966	26							
	Utility subtotal	3	1,579.9		26	2	0					
Potomac Edison Co.	R P Smith	3	34.5	1947	45			205	12,893	1.02	9.85	MD, PA
		4	75.0	1958	34							
	Utility subtotal	2	109.5		40	0	0					
Potomac Electric Power Co.	Chalk Point	ST1	364.0	1964	28	Yes		1,909	12,561	1.85	12.00	MD, PA, WV
		ST2	364.0	1965	27	Yes						
	Dickerson	ST1	196.0	1959	33			1,608	12,567	1.49	10.77	WV
		2	196.0	1960	32							
		3	196.0	1962	30							
	Morgantown	ST1	626.0	1970	22	Yes		2,747	12,695	1.68	11.64	MD, PA, WV
		ST2	626.0	1971	21	Yes						
	Utility subtotal	7	2,568.0		28	4	0					
Total Maryland	7	14	4,257.4	1963	29	6	0	10,001	12,822	1.39	10.23	

COAL-FIRED POWER PLANTS IN THE MID-ATLANTIC REGION

UTILITY	PLANT	UNIT	NAMEPLATE CAPACITY (MWe)	COAL (%)	START YEAR	AGE IN 1992	PHASE I UNIT	FGD INSTALLED	COAL USE (1,000 TONS)	BTU/LB	SULFUR (%)	ASH (%)	STATE OF ORIGIN
PENNSYLVANIA--1990													
Duquesne Light Co.	Cheswick	1	587.0		1970	22	Yes		1,427	12,404	1.60	11.81	PA, WV
	Elrama	1	100.0		1952	40		Lime(83%)	811	12,268	1.94	12.11	PA, WV
		2	100.0		1953	39		Lime(83%)					
		3	125.0		1954	38		Lime(83%)					
		4	185.0		1960	32		Lime(83%)					
	F R Phillips	1	75.0		1942	50		Lime(83%)	N/A				
		2	81.0		1949	43		Lime(83%)					
		3	81.0		1950	42		Lime(83%)					
		4	156.0		1956	36		Lime(83%)					
	Utility subtotal 3	9	1,490.0			38	1	8					
Metropolitan Edison Co.	Portland	1	171.7		1958	34	Yes		857	13,235	1.93	7.39	PA, WV
		2	255.0		1962	30	Yes						
	Titus	1	75.0		1951	41			538	13,250	1.51	6.90	PA, WV
		2	75.0		1951	41							
		3	75.0		1953	39							
	Utility subtotal 2	5	651.7			37	2	0					
Pennsylvania Electric Co.	Conemaugh	1	936.0		1970	22	Yes		4,850	12,346	2.21	14.44	PA
		2	936.0		1971	21	Yes						
	Front Street	1	18.8		1953	39			205	12,329	1.89	10.00	PA
		2	10.0		1917	75							
		3	15.0		1927	65							
		4	25.0		1944	48							
		5	50.0		1952	40							
	Homer City	1	660.0		1969	23			5,978	11,706	1.61	17.50	PA
		2	660.0		1969	23							
		3	692.0		1977	15							
	Keystone	1	936.0		1967	25			4,501	12,265	1.62	14.38	PA
		2	936.0		1968	24							
	Seward	4	62.0		1950	42			537	12,039	1.56	13.33	PA
		5	156.2		1957	35							
	Shawville	1	125.0		1954	38	Yes		1,606	12,129	1.93	13.67	PA
		2	125.0		1954	38	Yes						
		3	187.5		1959	33	Yes						
		4	187.5		1960	32	Yes						
	Warren	1	42.3		1948	44			243	12,392	1.86	10.16	PA
		2	42.3		1949	43							
	Williamsburg	5	25.0		1944	48			N/A				
	Utility subtotal 8	21	6,827.6			37	6	0					

COAL-FIRED POWER PLANTS IN THE MID-ATLANTIC REGION

UTILITY	PLANT	UNIT	NAMEPLATE CAPACITY (MWe)	COAL (%)	AGE IN 1992	PHASE I UNIT	FGD INSTALLED	COAL USE (1,000 TONS)	BTU/LB	SULFUR (%)	ASH (%)	STATE OF ORIGIN
Pennsylvania Power & Light Co.	Brunner Island	1	363.3		1961	31	Yes	3,930	12,414	1.95	13.72	PA
		2	405.0		1965	27	Yes					
		3	790.4		1968	24	Yes					
	Holtwood	17	75.0		1954	38		299	8,375	0.66	30.17	PA
	Martins Creek	1	156.3		1954	38	Yes	738	12,794	1.96	10.92	PA, WV
		2	156.3		1956	36	Yes					
	Montour	1	805.5		1971	21		4,363	12,469	1.88	13.57	PA
		2	819.0		1973	19						
	Sunbury	1	75.0		1949	43		1,103	10,536	1.54	22.16	PA
		2	75.0		1949	43						
Pennsylvania Power Co.	Utility subtotal 5	3	103.5		1951	41	Yes					
		4	156.3		1953	39	Yes					
		12	3,980.6		33	7	0					
		1	913.8		1975	17	Lime(92.1%)	6,044	12,081	4.17	11.90	OH, PA, WV
	Bruce Mansfield	2	913.8		1977	15	Lime(92.1%)					
		3	913.8		1980	12	Lime(92.1%)					
		1	37.5		1939	53		717	12,105	1.47	10.59	OH, PA
		2	40.2		1947	45						
	New Castle	3	97.8		1952	40						
		4	113.6		1958	34						
Philadelphia Electric Co.	Utility subtotal 2	5	136.0		1964	28						
		8	3,166.5		31	0	3					
		1	187.5		1954	38	MagOx(95%)	185	13,039	1.38	6.97	PA, WV
		1	353.6		1959	33	MagOx(95%)	617	13,080	1.56	7.57	KY, PA, WV
	Eddystone	2	353.6		1960	32	MagOx(95%)					
		3	894.7		34		3					
		2	50.0		1959	33						
		1	163.2		1958	34	Yes	905	12,342	1.81	11.48	PA
	Armstrong	2	163.2		1959	33	Yes					
		1	576.0		1969	23	Yes	3,719	12,878	2.19	9.47	PA, WV
West Penn Power Co.	Hatfields Ferry	2	576.0		1970	22	Yes					
		3	576.0		1971	21	Yes					
		3	299.2		1963	29	Lime(95%)	623	12,324	2.64	12.30	WV
		6	2,353.6		27	5	1					
	Utility subtotal 3	65	19,414.7	53%	1958	34	15	44,796	12,209	1.86	12.72	
		26										
	Total Pennsylvania											

COAL-FIRED POWER PLANTS IN THE MID-ATLANTIC REGION

UTILITY	PLANT	UNIT	NAMEPLATE CAPACITY (MW _e)	COAL (%)	START YEAR	AGE IN 1992	PHASE I UNIT	FGD INSTALLED	COAL USE (1,000 TONS)	BTU/LB	SULFUR (%)	ASH (%)	STATE OF ORIGIN
VIRGINIA-1990													
Appalachian Power Co.	Clinch River	1	237.5		1958	34			1,614	12,452	0.77	13.49	VA
		2	237.5		1958	34							
		3	237.5		1961	31							
	Glen Lyn	5	100.0		1944	46			539	12,651	0.81	10.72	KY, VA, WV
		6	237.5		1957	35							
	Utility subtotal 2	5	1,050.0			36	0	0					
Potomac Electric Power Co.	Potomac River	1	92.0		1949	43			937	12,818	0.77	8.23	KY, VA, WV
		2	92.0		1950	42							
		3	110.0		1954	36							
		4	110.0		1956	36							
		5	110.0		1957	35							
	Utility subtotal 1	5	514.0			39	0	0					
Virginia Power Co.	Bremo Bluff	3	69.0		1950	42			285	12,630	0.90	10.27	KY, WV
		4	185.3		1958	34							
	Chesapeake	ST1	112.5		1953	39			1,198	12,939	1.12	9.27	KY, VA, WV
		ST2	112.5		1954	38							
		ST4	239.4		1962	30							
		3	185.3		1959	33							
	Chesterfield	3	112.5		1952	40			2,805	12,719	1.04	8.77	KY, VA, WV
		4	187.5		1960	32							
		5	359.0		1964	28							
		6	693.9		1969	23							
	Passum Point	3	113.6		1955	37			581	12,604	0.97	9.16	KY, VA, WV
		4	239.4		1962	30							
	Yorktown	1	187.5		1957	35			529	13,017	1.32	8.23	KY, VA, WV
		2	187.5		1958	34							
	Utility subtotal 5	14	2,984.9			34	0	0					
Total Virginia		8	4,548.9	31%	1957	35	0	0	8,488	12,729	0.96	9.77	

COAL-FIRED POWER PLANTS IN THE MID-ATLANTIC REGION

UTILITY	PLANT	UNIT	NAMEPLATE CAPACITY (MW)e	COAL (%)	START YEAR	AGE IN 1992	PHASE I UNIT	FGD INSTALLED	COAL USE (1,000 TONS)	BTU/LB	SULFUR (%)	ASH (%)	STATE OF ORIGIN		
WEST VIRGINIA-1990															
Appalachian Power Co	John E Amos	1	816.3		1971	21			6,222	12,417	0.80	10.97	WV		
		2	816.3		1972	20									
		3	1,300.0		1973	19									
	Kanawha River	1	219.7		1953	39			497	12,539	0.77	11.58	WV		
		2	219.7		1953	39									
	Mountaineer	1	1,300.0		1980	12			2,887	12,402	0.68	10.95	KY,WV		
		6	4,672.0			25	0	0							
	Utility subtotal 3														
		Central Operating Co	1	152.5		1949	43			2,152	12,308	1.13	11.70	KY,WV	
			2	152.5		1950	42								
			3	152.5		1951	41								
			4	152.5		1952	40								
	5		495.6		1960	32									
	Utility subtotal 1	5	1,105.6			40	0	0							
Monongahela Power Co	Albright	1	69.0		1952	40			617	12,433	1.63	12.56	MD,WV		
		2	69.0		1952	40									
		3	140.3		1954	38	Yes								
	Fort Martin	1	576.0		1967	25	Yes		2,413	12,591	1.83	10.93	KY,MD,WV		
		2	576.0		1968	24	Yes								
	Harrison	1	684.0		1972	20	Yes		4,961	13,105	3.10	7.83	PA,WV		
		2	684.0		1973	19	Yes								
		3	684.0		1974	18	Yes								
	Pleasants	1	684.0		1978	14		Lime(90%) Lime(90%)	3,553	12,412	3.23	11.03	KY,OH,PA, WV		
		2	684.0		1980	12									
	Rivesville	5	35.0		1944	48			220	12,318	0.97	12.09	KY,WV		
		6	74.0		1951	41									
	Willow Island	1	50.0		1949	43			410	12,429	1.39	10.17	KY,PA,WV		
		2	153.0		1960	32									
Utility subtotal 6	14	5,172.3			30	6	2								
Ohio Power Co	Kammer	1	237.5		1958	34	Yes		1,951	12,170	4.26	12.74	OH,WV		
		2	237.5		1958	34	Yes								
		3	237.5		1959	33	Yes								
	Mitchell	1	816.3		1971	21	Yes		2,962	11,906	1.32	16.06	WV		
		2	816.3		1971	21	Yes								
	Utility subtotal 2	5	2,345.1			29	5	0							

COAL-FIRED POWER PLANTS IN THE MID-ATLANTIC REGION

UTILITY	PLANT	UNIT	NAMEPLATE CAPACITY (MW)	COAL (%)	START YEAR	AGE IN 1992	PHASE I UNIT	FGD INSTALLED	COAL USE (1,000 TONS)	BTU/LB	SULFUR (%)	ASH (%)	STATE OF ORIGIN
Virginia Power Co.	Mr. Storm	1	570.2		1965	27	Yes		4,247	12,311	1.77	14.13	MD,PA,WV
		2	570.2		1966	26	Yes						
		3	522.0		1973	19	Yes						
	Utility subtotal 1	3	1,662.4			24	3	0					
Total West Virginia	13	33	14,957.4	98%	1982	30	14	2	33,092	12,411	1.76	11.75	

CCT demonstration project site

Sources:

Cost and Quality of Fuels for Electric Utility Plants 1990, DOE/EIA-01191(90), August 1991, Table 10 and Table 1A

Inventory of Power Plants in the United States 1990, DOE/EIA-0095(90), October 1991, Table 20

Clean Air Act Amendments of 1990, Public Law 101-549, November 15, 1990

Note: Summary total averages are not weighted averages.

NON-UTILITY GENERATORS

Power Purchaser	Generating Company	Capacity (MW)
VERGEMIA		
Virginia Power Co.	Westraaco	68.0
Virginia Power Co.	Stone Container	48.5
Virginia Power Co.	Merck	6.0
Virginia Power Co.	Park 500-Philmont	19.6
Virginia Power Co.	Chesapeake	48.5
Virginia Power Co.	Union Camp	18.6
Virginia Power Co.	Cargill	1.8
Virginia Power Co.	James River Cogen	114.8
Virginia Power Co.	Cogenrix	114.8
Virginia Power Co.	Weyerhaeuser	28.4
Virginia Power Co.	Ultrasonics	50.0
Virginia Power Co.	Ultrasonics	60.0
Virginia Power Co.	Cogenrix-Rich	215.1
Total Virginia	13	804.8
WEST VERGEMIA		
Virginia Power Co.	Nortex, Inc.	80.0
Total West Virginia	1	80.0

Appendix B
Utility Planning Framework

Utility Planning Framework

Decisions about how utilities will meet the load requirements of their customers are made within the context of integrated resource planning. All states in the region, except West Virginia, require utilities to do integrated resource planning. An underlying principle is that electric customers' power requirements should be met by the "least-cost" alternatives. Although integrated resource planning is required only of investor-owned utilities, municipal and cooperative utilities generally employ the least-cost principle in their planning processes as well.

However, while least cost certainly is a very important criterion, it is not the only one utilities consider in the planning process. The following three criteria also seem to be used universally among utilities in Region 3:

1. Greatest flexibility—Short lead-time and minimum capital risk (based on an assumption that the future is very uncertain and program directions may need to change rapidly).
2. Maximizes the fuel of choice—Long-term availability and stability and the uncertainty of price and supply.
3. Environmental impact risks—Minimal and manageable long-run impacts, permitting requirements, emissions limits, uncertainty about potential unknown future impacts, and hazardous or toxic waste impacts.

In addition to these criteria, some utilities listed additional screening factors and three weighted timeframes (near-, mid-, and long-term). A composite list of these criteria follow:

- Economics—Customer and company (considered by Pennsylvania Power & Light to be most important in the near-term).
- Socio-political—Environmental political/regulatory, and social impacts.
- Technological—Planning flexibility, operating flexibility, availability (becomes more important over time as capacity ages).
- Service to customers—Reliability and customer acceptance (becomes more important over time).
- Participant test—Participant benefits and cost/benefits and impact on customer (especially important to demand-side options).
- Utility test—Utility cost/benefit, utility net present value, and impacts on utility revenue requirements (applicable to both demand and supply options).

-
- Rate impact measurement test—Impacts of a resource choice (demand or supply) on the average price of electricity.

In general, integrated resource planning involves the following activities:

- Forecasting future loads
- Evaluating demand-side management alternatives for their potential impact on future load (e.g., their ability to reduce peak loads, shape load profiles, conserve energy, and improve energy efficiency)
- Evaluating existing generating capacity and projecting needs for additional power to meet the load forecast
- Evaluating supply-side alternatives with potential for meeting the projected load
- Comparing and ranking demand-side and supply-side alternatives and evaluating them against multiple objectives and criteria
- Selecting the least-cost alternatives that together meet the forecast load requirements

The process may be repeated or iterated to "fine tune" the selection of demand and supply options. The outcome of the process is an integrated resource plan, or IRP, which public service commissions usually review and approve. IRPs are updated periodically to incorporate new policies, changing situations, and new information.

It is within the context of least-cost or integrated resource planning that utilities evaluate the competitiveness of supply and demand options. Moreover, this planning process shapes many of the choices that utilities will make concerning alternative environmental technologies and emissions control equipment.

Opportunities for the commercial deployment of CCTs exist within the alternatives on the supply side of the integrated resource planning process. The supply strategy a utility selects is, in general, a subset of the following composite list of supply-side options:

- Get the most out of existing facilities
 - Optimize the use of existing capacity
 - Return cold-reserve generating units to service
 - Expand maintenance programs
 - Extend the life of existing units
 - Aggressively shape load profiles and shave peak loads
 - Promote conservation and efficient utilization
 - Repower aging units
- Retire older, inefficient units
- Arrange load-diversity exchanges with non-affiliated utilities

-
- Sell power or capacity
 - Sell power to other utilities under short- or long-term contracts
 - Sell interests in excess capacity to other utilities
 - Buy power or capacity
 - Purchase bulk power from affiliated and non-affiliated utilities under short- or long-term contracts
 - Purchase generating capacity from affiliated utilities, non-affiliated utilities, or non-utility generators
 - Purchase power through competitive bidding from non-utility generators
 - Add new utility-owned generating capacity (peaking, intermediate, and/or baseload)

Among all these supply-side alternatives, only two offer potential markets for CCTs:

- Repowering and extending the life of aging units
- Adding baseload generating capacity

Specific technologies are evaluated more or less rigorously in order for a utility to rank technology alternatives for selection as supply-side resources within an integrated resource planning framework. Following are some of the technical factors that utilities consider:

- Unit performance and operating cost
- Construction cash flow
- Commercial and developmental status
- Maturity level
- Licensing and lead-time risks
- Cost risk
- Capital cost
- Fixed operating and maintenance costs
- Variable operating and maintenance costs
- Fuel costs at various capacity factors
- Capacity factor
- Total levelized \$/kW as a function of capacity factor (including fixed charges)

Several utilities indicated that they use the Electric Power Research Institute's Technology Assessment Guide (TAG) as a basis for ranking capital and variable operating costs, among other things.

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