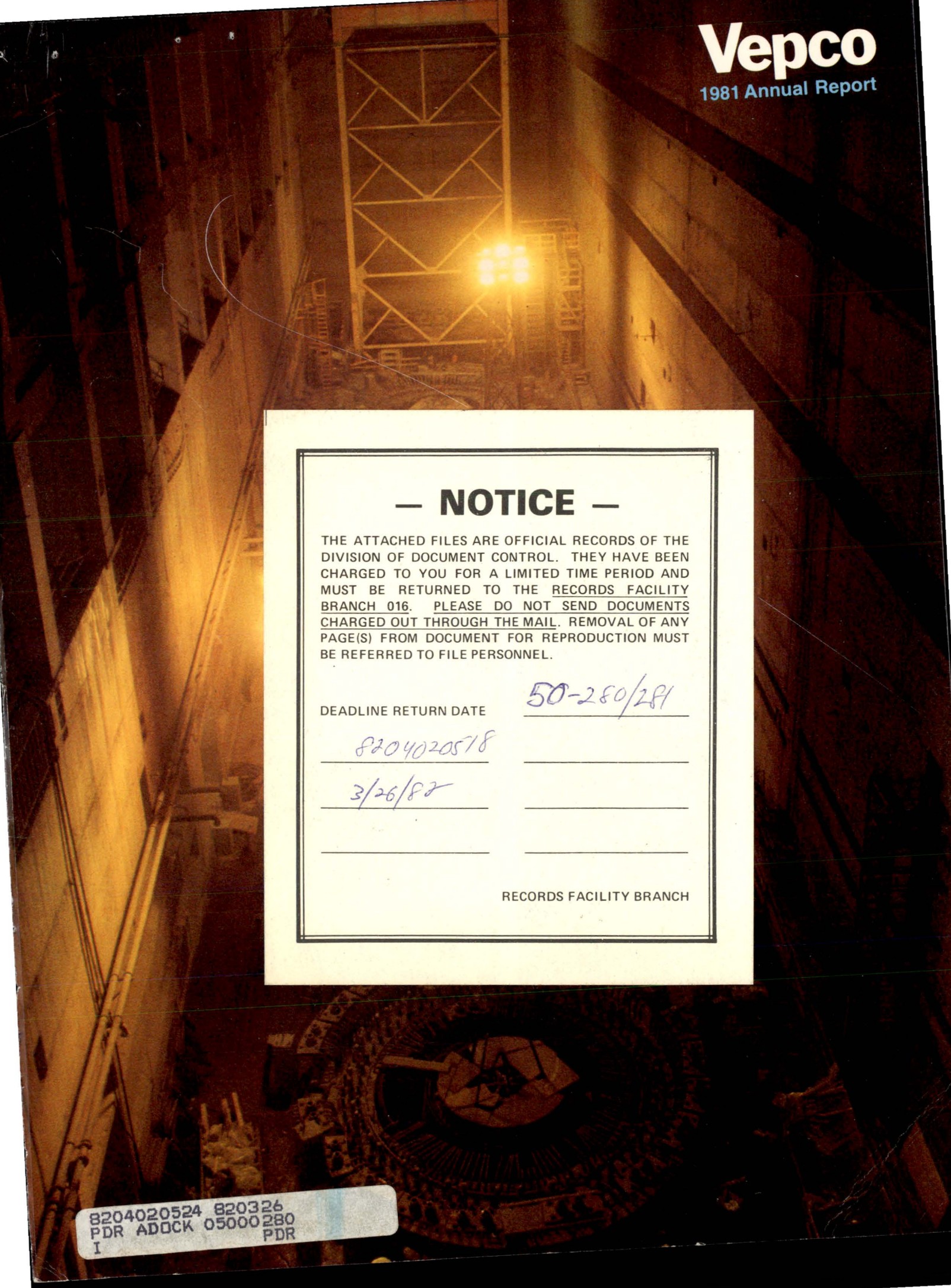
Vepco

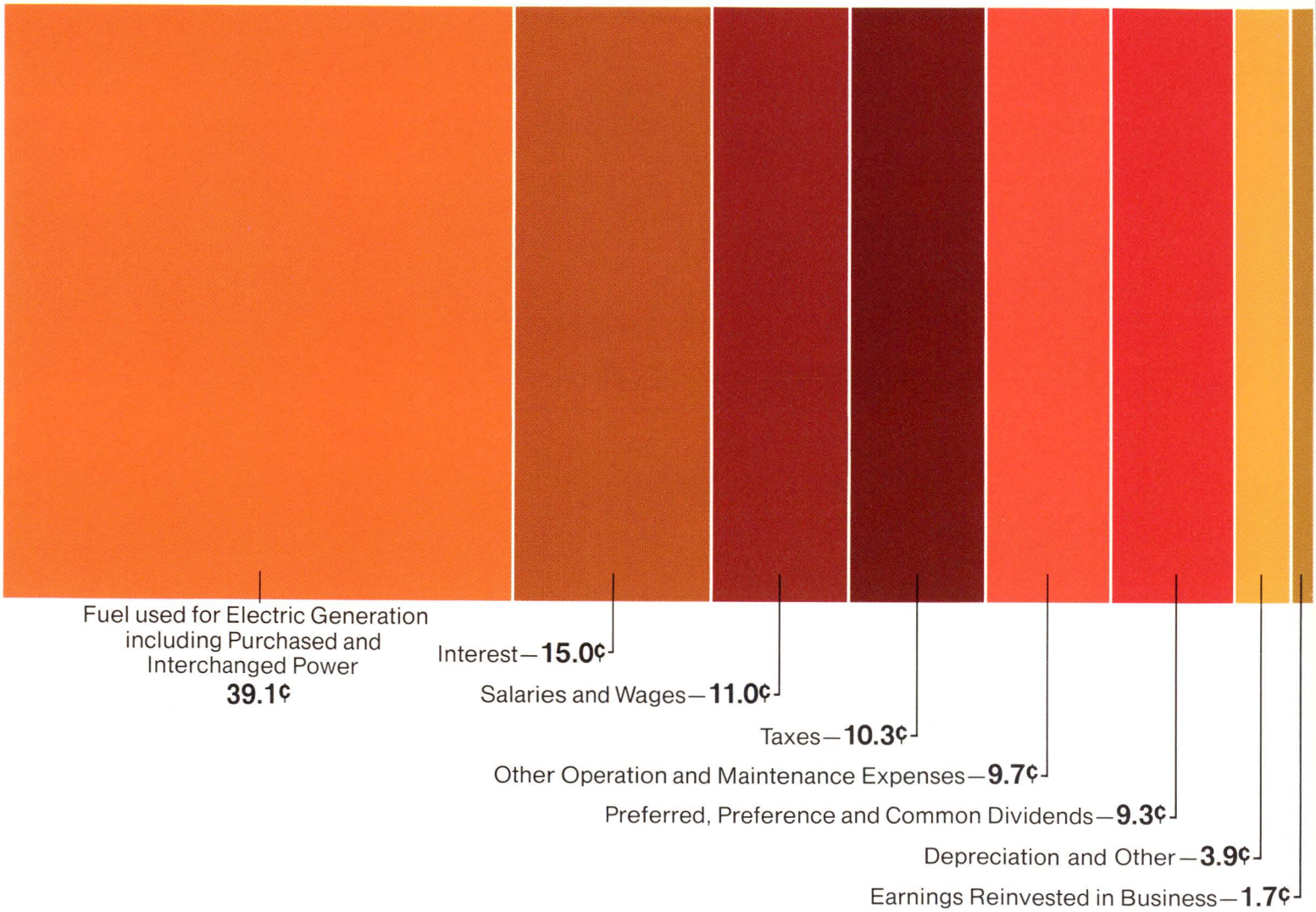
1981 Annual Report



On the Cover

Construction progresses in the turbine building at Bath County Pumped Storage Station. The 2.1 million kilowatt project is now 60 percent complete.

Disposition of the 1981 Revenue Dollar



Contents

1981 Highlights

	1981	1980	Increase (Decrease)	% Increase (Decrease)
Financial				
Total Operating Revenues	**$2,161,853,000**	$2,119,774,000	$ 42,079,000	2.0
Total Operating Expenses	**$1,693,221,000**	$1,730,242,000	$(37,021,000)	(2.1)
Net Income	**$ 237,780,000**	$ 241,620,000	$ (3,840,000)	(1.6)
Balance Available for Common Stock	**$ 180,614,000**	$ 184,329,000	$ (3,715,000)	(2.0)
Average Shares of Common Stock Outstanding	**101,856,000**	95,520,000	6,336,000	6.6
Stockholders—Common, Preferred and Preference	**213,700**	206,800	6,900	3.3
Earnings Per Share of Common Stock	**$1.77**	$1.93	$(.16)	(8.3)
Dividends Per Share of Common Stock	**$1.425**	$1.40	$.025	1.8
Book Value Per Share of Common Stock	**$18.64**	$18.63	$.01	0.1
Capital Expenditures	**$ 676,295,000**	$ 681,120,000	$ (4,825,000)	(0.7)
Long-Term Financings	**$ 421,693,000**	$ 480,874,000	$(59,181,000)	(12.3)
Operations				
System Output—Megawatt-hours (thousands)	**42,889**	42,489	400	0.9
Year-End Capability—Megawatts	**10,959**	10,830	129	1.2
Service Area Peak Load—Megawatts	**8,638**	8,484	154	1.8
Customers—Electric—Heating	**352,048**	325,728	26,320	8.1
—Other	**1,029,052**	1,021,372	7,680	0.8
Total Electric	**1,381,100**	1,347,100	34,000	2.5
Customers—Gas	**121,400**	120,100	1,300	1.1
Average Residential Use—Electric—Kilowatt-hours	**10,948**	11,056	(108)	(1.0)
Employees—Full Time	**11,487**	10,580	907	8.6

Virginia Electric and Power Company • One James River Plaza • Richmond, Virginia 23261

To Our Stockholders:

Steps taken in 1980 to improve all elements of the Company's operations became giant strides in 1981. Achieving those improvements, many of which included costly upgrading of plant equipment, was an expensive but necessary investment in the future. The progress made in meeting operational goals during 1981 will begin to reap significant financial rewards in 1982, and will position Vepco favorably for the rest of the decade and beyond.

The goals set were to: increase the nuclear component in our energy supply mix; continue our aggressive conversion of oil-fired units to coal; improve productivity of all fossil generating stations; and reduce our external financing requirements. The results were excellent.

Energy Supply

The improvement in Vepco's energy supply mix in 1981 was dramatic. Our four nuclear units were on line during the year and performed well. As a result, nuclear units generated 41 percent of our total energy supply. This increase from 27 percent nuclear generation in 1980 exceeded our goal for the year. Coal generation amounted to 31 percent for the year, up from 25 percent in 1980. With an aggressive program to convert oil-fired units to coal our dependence on expensive oil-fired generation dropped from 19 percent in 1980 to 8 percent in 1981.

Nuclear Units

The return to service of Surry Power Station Unit 1 in July marked the completion of the massive construction project to replace the steam generators on both nuclear units at Surry. This was the first such replacement project to be done in the world on commercial nuclear reactors.

The total cost was about $113 million, but was money well spent. These two nuclear units cost approximately $257 a kilowatt of capacity when they were originally built. The steam generator replacement increased the total cost to almost $330 a kilowatt, but it would cost more than three times that amount today to construct new nuclear generating units of similar size and quality.

Although both our North Anna nuclear units experienced outages in 1981 as a result of problems with turbine rotors and transformers, both non-nuclear components, the resourcefulness of our engineering, construction and operational team kept these outages to a minimum. Both units finished the year with good performance records.

Fossil Fuel Units

The most important capital improvement project underway is the conversion of four large, coal-fired units from forced to balanced draft combustion. Phase one of this project—making modifications necessary prior to installing new equipment—was completed in 1981. Phase two—the installation of balanced draft combustion hardware—will be completed in 1983. This conversion project will lead to reduced maintenance costs and improved efficiency of these units.

The improvement program extends into virtually every aspect of the fossil fuel plant operations—upgraded personnel qualifications and training, increased staffing, major renovations of existing equipment, and improved administrative procedures.

This program is scheduled for completion by 1984, but we began seeing positive results in 1981. The forced-outage rate at our five largest coal-fired units was significantly reduced, and their availability was increased. Our smaller coal-fired units also operated extremely well during the year.

We completed conversion of our sixth oil unit to coal—Possum Point Unit 3. As of 1981, the 1.6 million kilowatts of capacity Vepco has converted accounted for over a third of all oil to coal conversions in the United States.

William W. Berry, President and T. Justin Moore, Jr., Chairman of the Board

New Gas Division

The Company in 1981 established a new Gas Division with the name Virginia Natural Gas. By mid-1982, the division will have about 415 employees assigned to it, all of whom are devoting full-time to gas operations. We are confident this new division will lead to even better service to our 120,000 gas customers, and an expansion of our gas market.

Meeting New Demand

We anticipate peak demand to grow between 2 to 3 percent a year in our service area during the remainder of the 1980s and 1990s. The Bath County Pumped Storage Project and North Anna Unit 3, our fifth nuclear unit which is now under construction, will give us the means of meeting projected demand growth through 1991, with adequate reserves. We initiated in 1981 a major three-year study of two conventional and a dozen non-conventional means of meeting or reducing growth in power demand for the rest of the 1990s. The study will help us to identify the lowest cost means of meeting or reducing our future power demand.

Reducing Financial Burden

We also made significant progress in 1981 in decreasing the financing burden of our current construction projects at Bath and North Anna. Vepco agreed to sell 20 percent of the Bath County Project, and to sell or sell capacity of an additional 20 to 30 percent of the facility, to Allegheny Power System, Inc. (APS). Subject to obtaining all regulatory approvals, we would receive an initial payment of approximately $190 million.

The Company also agreed in principle to sell portions of our North Anna Power Station to the Old Dominion Electric Cooperative. If the sale is completed by the mid-1982 target date, we will receive about $300 million for the existing facilities, and about $500 million in the future as Old Dominion's share of future costs of North Anna Unit 3.

Rate Decisions

In 1981, we obtained rate increases amounting to $222 million on an an-

nual basis. While we did not achieve all we hoped for, there were significant gains.

Our Virginia service area accounts for 1.3 million retail customers and 85 percent of our revenues. In August, the State Corporation Commission granted $132 million of the $190 million we requested and authorized a 15 percent return on equity with an opportunity for 15.5 percent, if certain conditions are met.

We do not consider this an adequate return in view of current economic circumstances, but it improves upon the 13.5 percent return that had been authorized since 1975. The commission confirmed that Vepco's cancellation of North Anna Unit 4 was a prudent decision and authorized recovery of the Company's investment and cancellation costs. The commission also authorized the Company to earn cash income on additional expenditures for North Anna Unit 3 and other new projects commencing after September 1, 1981. This will lower Vepco's future external financing requirements.

The commission did not allow us to earn on the unamortized balance of the North Anna Unit 4 project, which was cancelled late in 1980. This was a particularly regrettable decision because we strongly believe that Vepco's stockholders are entitled to a return on this investment.

The North Carolina Utilities Commission in October granted a rate increase of $12.9 million, which was 78 percent of our request. The commission also permitted the recovery over a 10-year period of costs associated with the cancellation of North Anna Unit 4, including the inclusion of the unamortized balance of such costs in the rate base. At the same time, the commission reduced our authorized return on equity to 10 percent as a penalty for alleged substandard performance of fossil units in 1979. We considered an appeal, but decided that filing a new rate case in early 1982 was the quickest and best means of correcting this grossly inadequate authorized return on equity. On January 25, 1982, the Company filed a general rate increase for $20.5 million with a proposed 17.5 percent return on common equity.

Earnings

Vepco has undertaken a number of programs that will have major long-term positive effects on earnings. Though some of these programs will have a strong or moderate positive impact in the short term, the immediate effect of others on 1981 earnings was negative. These negative impacts, combined with high interest rates and a weak economy, resulted in Vepco's earnings dropping 16 cents per share, from $1.93 in 1980 to $1.77 in 1981.

We are confident, however, that our financial performance over a number of years will be improved for having taken these steps.

If the sale of a portion of the Bath County Project had been completed in 1981 it would have had a positive effect on 1981 earnings of $3.3 million. Assuming further regulatory approvals, we can still look forward to positive effects from this sale in 1982 and beyond.

Vepco successfully sought authorization from the Virginia State Corporation Commission to earn a cash return on expenditures for new projects and on additional expenditures for North Anna Unit 3 after September 1, 1981. During the current year, this had a small positive effect. But in the long term it will have a strong positive impact by increasing cash flow and reducing financing requirements.

Two other Vepco actions—the cancellation of North Anna Unit 4 and the planned sale of a portion of the North Anna Power Station to the Old Dominion Electric Cooperative—are having or will have short-term negative effects on earnings, which will become positive impacts in the long term.

The failure of the Virginia State Corporation Commission to allow Vepco to earn on the unamortized balance of the investment in the cancelled North Anna Unit 4 hurt our earnings in 1981. In the long term, however, the cancellation will have a positive effect on earnings by reducing Vepco's external financing requirements.

Similarly, the sale of a portion of the North Anna Power Station will have a short-term negative impact on recorded earnings as a result of the loss of sales which would otherwise be made to the Cooperative, and the loss of return on investment applicable to the facilities being sold to the Cooperative. But if the sale is completed in 1982, as hoped, Vepco will receive $300 million initially and an estimated $500 million during the remaining construction of North Anna Unit 3. This will allow us to reduce our financing requirements.

Our coal conversion program has a short-term negative impact because of the cost of financing the project. But these conversions provide immediate benefits to our customers by reducing fuel costs and they facilitate improved rate decisions over the longer term.

The major program we have underway to improve our coal-fired units also has a negative immediate impact because of its cost. But these improvements also will reduce fuel costs and improve our regulatory climate, thereby benefitting both customers and stockholders in the long term.

Three external factors also are affecting our current earnings and future prospects: high interest rates during much of 1981; changes in Federal tax law; and the condition of the economy.

High interest rates, combined with the sensitivity of a large share of Vepco's debt to short-term interest rate increases, produced interest costs $56 million greater in 1981 than in 1980. If interest rates fall, there will be a positive effect on Vepco's earnings in 1982.

The accelerated depreciation provisions of the Economic Recovery Tax Act of 1981 had little impact this year, but in 1982 and beyond they will improve cash flow and indirectly benefit earnings. The new tax treatment of reinvested dividends beginning in 1982 will help us obtain additional capital.

Finally, Vepco's earnings were adversely affected in 1981 by the national economic slowdown. Improvement in the national economy in the future will have significant positive effects on the Company's sales and earnings.

We are confident for all these reasons that the long-term prospects for Vepco point to improved financial results in the future. As evidence of that confidence, the Board in October increased the quarterly dividend by 2.5 cents per share to 37.5 cents per quarter for an indicated annual rate of $1.50.

During the past several years, Vepco has been making the difficult transition into a new era of expensive energy. We now are positioned and organized to adapt promptly to new uncertainties. The progress we made in improving our power stations and operations in 1981 provide the basis for the improved financial performance we are confident will come in the years ahead.

T. Justin Moore, Jr.
Chairman of the Board

William W. Berry
President

Financial Results

Revenues

Vepco's operating revenues in 1981 totaled $2.2 billion, up $42.1 million, or 2 percent over 1980. Our electric business generated $2,069.8 million, on sales of 39.9 billion kilowatt-hours. Vepco's gas business generated $92.1 million, a 31 percent increase over 1980.

The small increase in total operating revenues was the result of reduced fuel revenues, and a generally sluggish national economy.

Expenses

Total operating expenses were $1.7 billion, down $37.0 million, or 2 percent from 1980—primarily because of reduced fuel expenses. In 1981, fuel expenses, including purchased and interchanged power costs, were $845.0 million, down $171.0 million from 1980, a 17 percent decrease. We were able to achieve this reduction in fuel cost because of the increased nuclear component in our total power generation mix, and generally stabilizing prices in all fuels.

Earnings and Dividends

Earnings were down 16 cents per share, from $1.93 in 1980 to $1.77 in 1981. However, the quality of earnings—the proportion of cash in recorded earnings—was improved over 1980. The Company paid its holders of common stock dividends of $1.425 per share in 1981, compared with $1.40 per share in 1980. In October, 1981, Vepco increased the quarterly common stock dividend by 2.5 cents raising the quarterly dividend from 35 cents to 37.5 cents, and the indicated annual rate to $1.50, compared to $1.40 per share in 1980.

The following table shows the Company's high and low sales prices of common stock, principally traded on the New York Stock Exchange, and dividends paid for the last two years.

1980	High	Low	Dividends
First Quarter	12⅜	9⅛	$ .35
Second Quarter	12¼	9¾	.35
Third Quarter	12	10¼	.35
Fourth Quarter	11⅛	9½	.35
			$1.40

1981	High	Low	Dividends
First Quarter	11⅞	10⅛	$ .35
Second Quarter	12⅜	10⅝	.35
Third Quarter	12½	10¾	.35
Fourth Quarter	13⅛	10⅛	.37½
			$1.42½

On December 31, 1981 there were 190,735 holders of record of the Company's common stock.

Rate Relief

The Company aggressively pursued rate relief in all of its major jurisdictions during 1981. With inflation rapidly escalating our maintenance and operating expenses, other than fuel costs, this additional rate relief was needed to improve our financial health, and to permit us to provide for future growth in demand and continued reliable service.

Rate increases granted in 1981 by regulatory authorities and negotiated with governmental customers total $222 million on an annual basis.

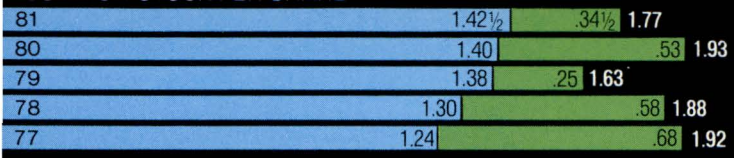
- The Virginia State Corporation Commission granted rate relief of $131.8 million effective August 29. The commission's order established a return on equity in the range of 15 to 15.5 percent but set the level of return at 15 percent for the present. This was up from the 13.5 percent return on equity set in 1975, but below the 16.5 percent requested by Vepco. The commission allowed an overall return of 10.68 percent.
- The North Carolina Utilities Commission granted a $12.9 million rate increase effective August 1, representing 78 percent of Vepco's request. The commission's order authorized a return on equity of 10 percent with an overall return of 9.37 percent. The decision permitted Vepco to earn a cash return on construction work in progress in the rate base through March 31, 1981 (1979 test year). The commission also approved the recovery over a 10-year period of costs associated with the cancellation of North Anna Unit 4 and permitted the inclusion of the unamortized balance of such costs in the rate base.
- The West Virginia Public Service Commission granted the Company an increase of $2.4 million effective January 1, 1981. The commission authorized an overall rate of return of 10.41 percent based on a 14.5 percent return on equity.
- On August 26, the Federal Energy Regulatory Commission (FERC) approved a settlement increase of $16.5 million effective January 14, 1981 for the Company's cooperative and municipal customers. This increase was attributable to the commercial operation of North Anna Unit 2.
- The FERC also allowed an increase of $38 million to go into effect September 1, 1981, subject to refund. The Company's requested increase was based on an overall cost of capital of 11.01 percent, including 15 percent return on common equity. On December 31, 1981, the Company filed with the FERC a proposed settlement with the cooperative and municipal customers for a combined increase of $32.4 million.
- Vepco's electric rates to a number of state, county and municipal customers, and Federal government agencies, are established by negotiation rather than by regulation.

Large Federal government customers, such as military installations and the General Services Administration (GSA), have agreed to abide by rate decisions rendered by the FERC for Vepco's municipal resale customers. Accordingly, Vepco received an annual increase of $4.4 million effective January 14, 1981, attributable to North Anna Unit 2 going into service. Additionally, these Federal customers began paying a general increase of $8.4 million effective September 1, 1981, subject to refund.

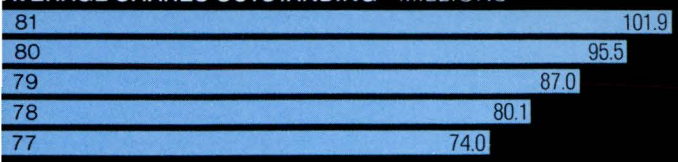
Vepco's rates for the National Aeronautics and Space Administration (NASA) are established by separate negotiations. Agreement with NASA was reached in 1981 for an annual increase of $1.3 million.

Vepco still has many long-term contracts for electricity at extremely low rates with municipalities in Virginia. Expiration of one of these contracts in 1981 resulted in an increase in revenues from the City of Richmond of $6.4 million at an annual rate effective December 1, 1981. Between now and January 1, 1983, several other large municipal customers' long-term contracts will expire, resulting in a further increase of revenues of approximately $15 million per year.

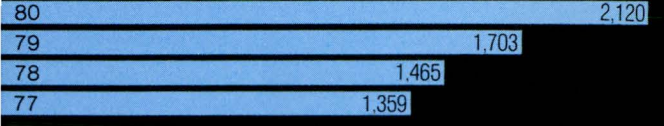
EARNINGS: DIVIDENDS RETAINED EARNINGS
—COMMON STOCK PER SHARE



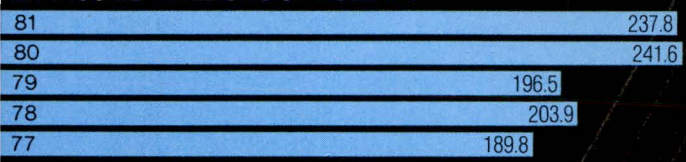
AVERAGE SHARES OUTSTANDING—MILLIONS



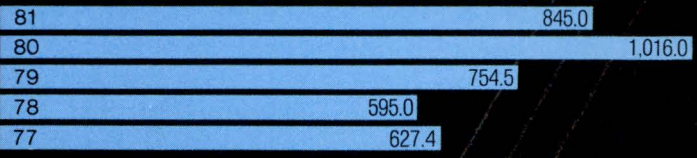
REVENUES—MILLIONS OF DOLLARS



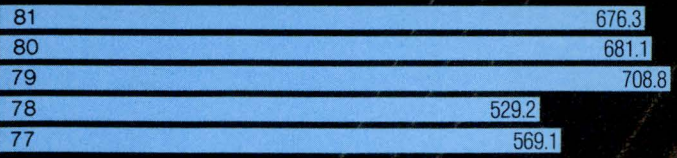
NET INCOME—MILLIONS OF DOLLARS



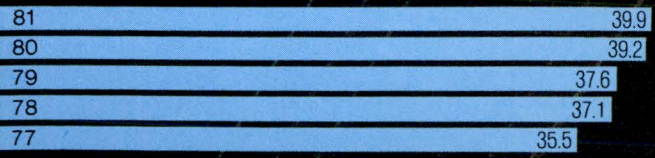
FUEL EXPENSES—ELECTRIC INCLUDING PURCHASED AND INTERCHANGED POWER—MILLIONS OF DOLLARS

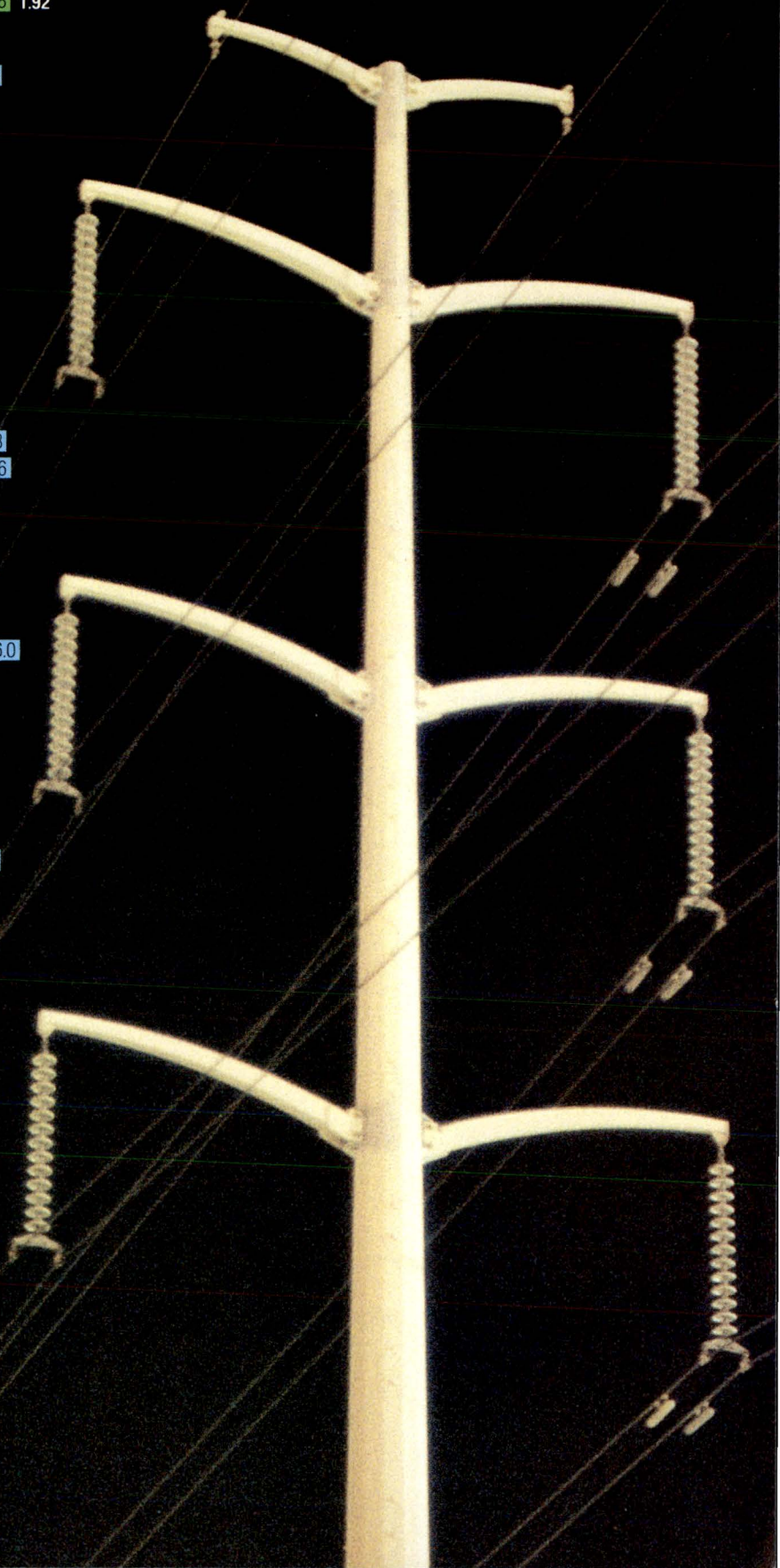


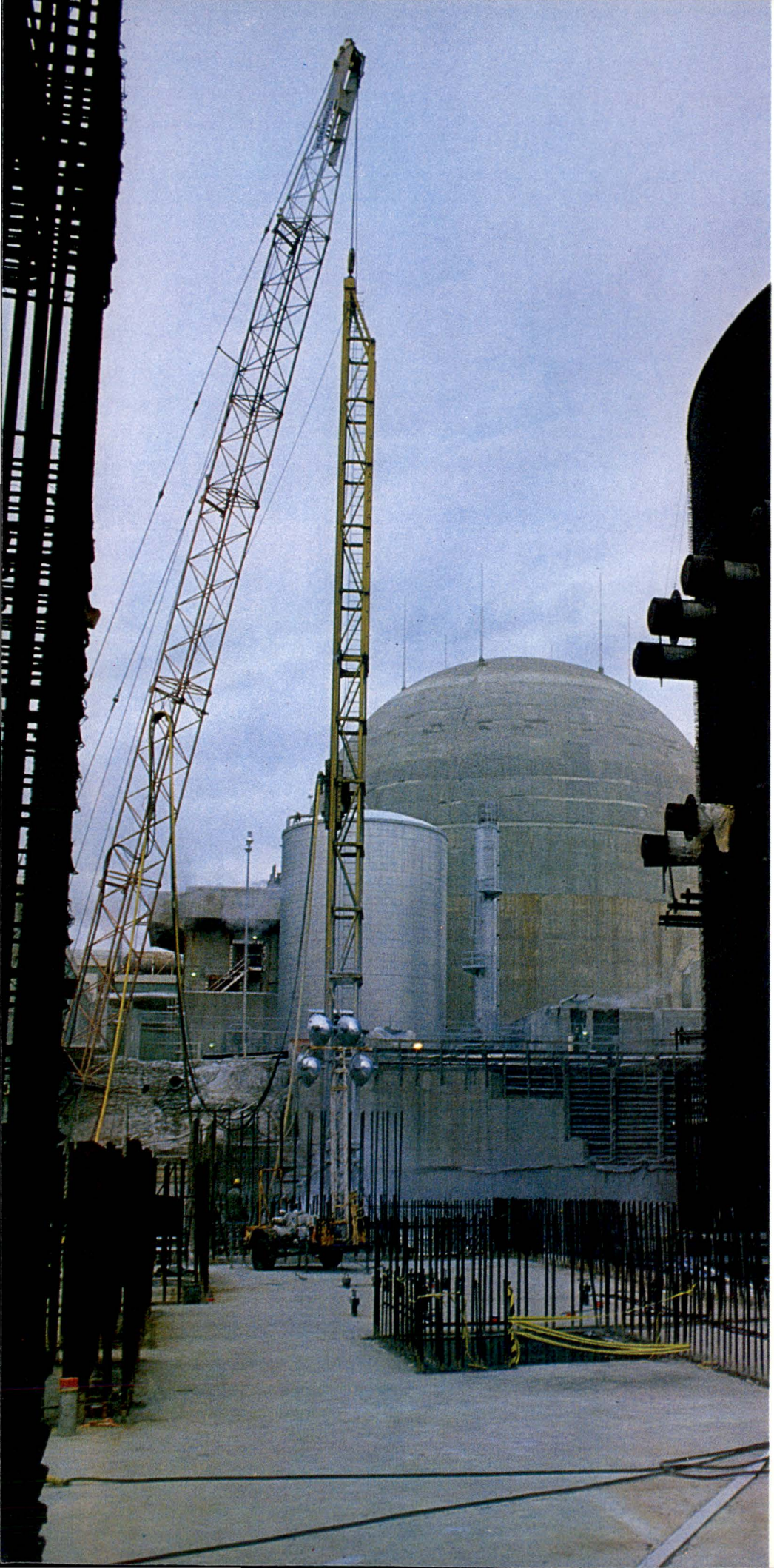
CAPITAL EXPENDITURES—MILLIONS OF DOLLARS



SALES OF ELECTRICITY—MILLIONS OF Mwh







Vepco achieved a greatly improved energy supply mix in 1981 as a result of increased efficiency of its nuclear and fossil unit operations, combined with continuing oil-to-coal conversions.

In 1981, the Company's four nuclear units accounted for 41 percent of Vepco's total energy supply, versus 27 percent in 1980. Coal units provided 31 percent of the total energy supply mix in 1981. At the same time, oil-fired generation decreased from 19 percent of the total energy supply mix in 1980, to 8 percent in 1981.

This meant that the number of kilowatt-hours produced by Vepco's coal-fired units increased 21 percent from 10.8 billion kilowatt-hours in 1980, to 13.1 billion kilowatt-hours in 1981. Similarly, the energy output from Vepco's nuclear units increased 55 percent in 1981, from 11.5 billion kilowatt-hours in 1980 to 17.8 billion in 1981.

This increased nuclear component in the generation mix enabled Vepco to reduce its fuel expenses in 1981 by $171.0 million—from $1,016.0 million in 1980 to $845.0 million in 1981. We are projecting a 47 percent nuclear component in the power generation mix for 1982, and consequently another reduction in total fuel costs.

Nuclear Units

Surry Power Station Unit 1 returned to service on July 8, 1981, following completion of a massive construction project to replace its three steam generators. By completing this project about two months ahead of schedule, Vepco reduced system fuel expenses by approximately $31 million. Vepco previously completed replacement of the steam generators in Surry Unit 2 in August 1980.

These replacement projects were necessitated by a problem that is generic to nuclear units of the design employed at Surry, and one that still confronts many U.S. utilities. They were the first such replacements ever performed on commercial nuclear reactors, and established a standard of engineering and construction excellence for other companies.

Both Surry units operated at high capacity factors in 1981. Capacity factor is a measure of a generating unit's productivity. A generating unit operating at full power every day of the year would have a capacity factor of 100 percent. This theoretical maximum

Construction continues on North Anna Unit 3. Units 1 and 2 are in service and performing at top capacity.

Current Operations

cannot be attained in practice because nuclear units require periodic outages for maintenance and refueling.

Following the successful completion of the steam generator replacement, Surry Unit 1 operated at a capacity factor of 77 percent. Surry Unit 2 operated at a capacity factor of 84 percent.

North Anna Units 1 and 2 also performed well during the year. North Anna Unit 2 achieved a capacity factor of 71 percent in 1981. North Anna Unit 1 was out of service from January 1 to April 10 for scheduled refueling, required seismic reanalysis of piping systems and replacement of a turbine rotor. Due to this outage, North Anna Unit 1 had a capacity factor of only 58 percent for the year. However, once it returned to service on April 10, the unit operated at a capacity factor of 82 percent to the end of the year.

Vepco's team of engineering, construction and operational personnel demonstrated considerable ingenuity and skill in achieving these levels of nuclear operations.

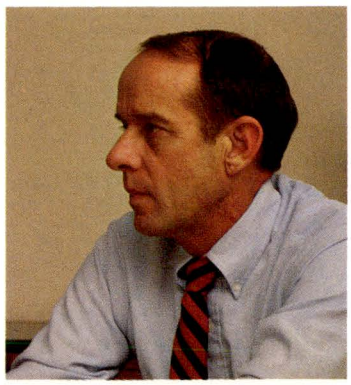
Although North Anna Unit 2 experienced failure of several main transformers in June and July 1981, Vepco operations and construction personnel turned this to advantage by accomplishing many design modifications that had been scheduled for a planned fall maintenance outage. This allowed Vepco to cancel the fall outage, allowing uninterrupted operation which contributed significantly to the unit's high net operating capacity for the year.

During the outage on North Anna Unit 1 last winter, a turbine inspection revealed cracks in the discs of one of the low-pressure turbine rotors. Normally, procuring and installing a replacement rotor would take many months, adding significantly to the length of the outage. However, Vepco personnel quickly located a replacement rotor in Pennsylvania, and overcame unique transportation problems posed by the rotor's enormous size. The Vepco team's resourcefulness allowed the turbine repairs to be completed without affecting the duration of the outage.

Fossil Station Operations

The centerpiece of Vepco's continuing program to improve the efficiency of its fossil stations is the conversion of four large coal-fired units from pressurized to balanced draft combustion. These conversions will increase the operating availability of these units, and will significantly reduce future maintenance costs.

These complex projects are most economically done in two phases. The first phase, consisting of modifications to existing equipment, was completed in 1981. The installation of new equipment to complete the conversion of all four units will be accomplished by 1983.



Power Group staff meeting including (left to right) E.A. Baum, A.L. Parrish, III, W.C. Spencer, J.I. Oatts (top picture) and (below) J.H. Ferguson and R.H. Leasburg.

Electrostatic Precipitators

To meet the stringent air quality standards imposed in the 1970s, Vepco is installing new electrostatic precipitators or upgrading existing equipment to control particulate emissions from coal-fired units. Installation and testing of a new precipitator was completed at Chesterfield Unit 5 in 1980, and modification of an existing precipitator was begun on Chesterfield Unit 6. Precipitator construction projects were underway on six other coal units during the year. When this precipitator program is completed in 1984, it will allow Vepco to operate its coal-fired units at full power, increasing their efficiency and the amount of electricity they can generate.

Four additional precipitators are planned for units to be converted to coal by 1986.

During 1981, significant progress also was made in improving the current availability and reliability of the major coal-fired units in the system: Mt. Storm Units 1, 2, and 3, and Chesterfield Units 5 and 6.

These five units, with combined capacity of 2.5 million kilowatts, showed a 4 percent increase in operating availability and a 5 percent decrease in forced outage rate in 1981 compared to 1980. Vepco's smaller fossil units also showed operational improvement during the year, with a 7 percent increase in operating availability and a 3 percent decrease in the forced outage rate. This encouraging improvement over the year came as a result of both administrative adjustments and major investments in upgrading plant equipment.

Longwall Mining System

Yet another significant improvement in Vepco's fossil operations in 1981 was the installation of a longwall mining system at our Laurel Run Mine, adjacent to our Mt. Storm Power Station in West Virginia. This $6 million system, which went into service in September, three months ahead of schedule, cuts coal in 400-foot strips at a much faster rate than conventional mining techniques. During its four months of operation in 1981, it produced an average of 833 tons of coal per eight-hour shift, an increase of almost 600 tons per shift over the old continuous mining system.

Coal Conversions

Vepco is conducting the nation's largest program of converting oil-fired units to coal. On February 11, 1981, Possum Point Unit 3 returned to service following conversion, the sixth oil-fired unit converted to coal since the

The longwall mining system greatly improved coal production at our Laurel Run Mine.

Company began the program in 1975. These six units, with a total capacity of 1.6 million kilowatts, represent more than one-third of all the oil-to-coal conversions in the country. With these six converted units burning coal instead of oil in 1981, Vepco was able to reduce fuel costs significantly by displacing millions of barrels of higher-cost oil.

In 1981, the Company added four more oil units—Portsmouth Units 1 and 2, and Possum Point Units 1 and 2—to the conversion program. These units, with a combined capacity of 345,000 kilowatts, will be converted from oil to coal early in 1986. When the entire conversion program is completed in 1986, 14 units with a total capacity of 2.5 million kilowatts will have been converted. This enormous shift from oil-fired to coal-fired units will save customers an estimated $1 billion in fuel costs through 1986.

Price Performance

The Company's continuing shift away from expensive oil-fired units to nuclear and coal-fired units enabled it to reduce its average price per kilowatt-hour in 1981, to 6.08 cents compared to 6.13 cents in 1980. Over the same period of time, the average rate of inflation as measured by the Consumer Price Index (CPI) increased 10.4 percent.

Over the next decade, we expect our rates to increase in line with, or less than, the CPI. This should have beneficial effects on our regulatory environment.

Conservation, Load Management and Cogeneration

Conservation, load management and cogeneration can allow Vepco to delay the need for building costly new generating facilities. Building new generating capacity is unattractive because current regulation does not allow full recovery of the cost of new capital.

Programs already underway in conservation, load management and cogeneration reduced, or helped to meet, 100,000 kilowatts of demand in 1981. To step up those efforts, Vepco established on July 1, 1981, the Economic Development and Energy Services Department.

In addition to working with our customers, the new department assists state and local governments in the Company's service area in seeking new business and industry, emphasizing energy-efficient development that will result in as small an increase in demand as possible.

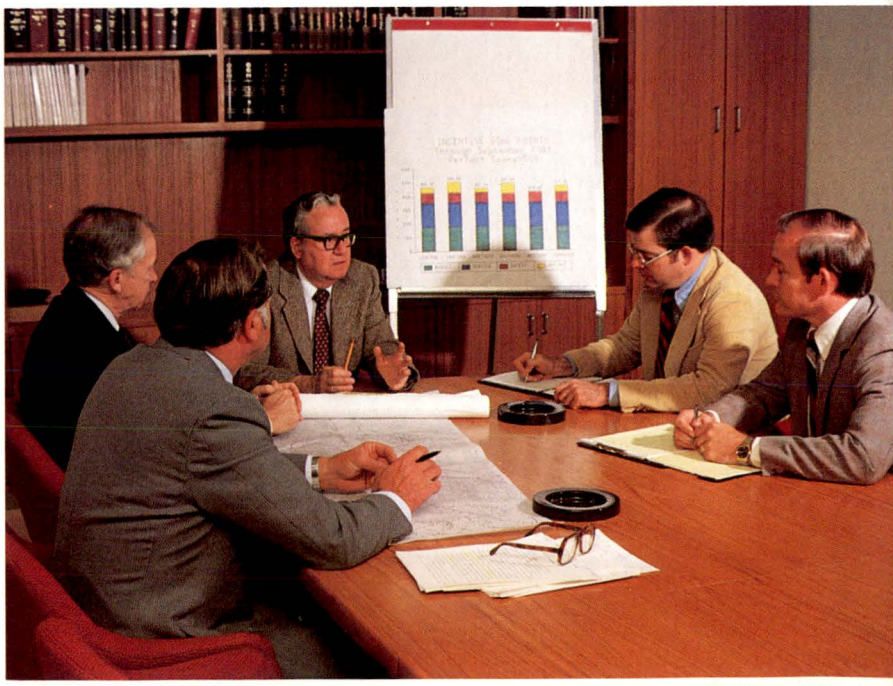
In 1981, the department initiated a Home Energy Audit Program using instant computer analysis to evaluate cost and effectiveness data for customers. This program was implemented in selected areas in each division in 1981, and will be expanded in 1982.

The Company also continued to perform industrial and commercial energy audits for small and medium-sized firms that lack sophisticated energy management programs. These audits reduced Vepco's summer peak demand by an estimated 71,000 kilowatts, and winter peak demand by 62,000 kilowatts.

Test programs for time-of-usage rates were continued. In these programs, lower rates are charged for electricity used during off-peak periods, thereby saving customers money and enabling Vepco to reduce its peak demand. Pilot direct load management programs that allow the Company to control customers' water heaters, and development of cogeneration potential with industrial customers that use process steam or produce combustible wastes, also were continued in 1981.

Transmission and Distribution

During 1981, the Company expanded its Supervisory Control and Data Acquisition System (SCADA), a computerized system designed to localize and identify power outages. This system allows Vepco to restore service more rapidly, and reduce the manhours required to make repairs.



The Commercial Operations group discusses Vepco's Energy Conservation Program (left to right) G.C. Headley, Jr., W. Bugg, Jr., W.L. Proffitt, R.C. Steele, III, and J.L. Causey.

As the result of a spell of record-breaking temperatures in parts of Vepco's service area, a new summer peak load of 8,638 Mw was established on June 16, 1981. This exceeded by 1.8 percent the previous peak of 8,484 Mw set in August of last year. The 1981 winter peak demand of 8,451 Mw set in January was surpassed on January 12, 1982, when a new winter peak of 8,879 Mw occurred.

Projected future growth in load under normal weather conditions is the major factor determining the need for new capacity. Variations in load as a result of extreme weather are one of the factors that must be considered in setting capacity reserve margins required for reliable service.

Unless it is constrained by demand-reducing programs, peak demand in Vepco service territory is expected to grow between 2 to 3 percent a year through the mid-1990s. By the year 1995, peak demand for electricity will increase by nearly 3.0 million kilowatts compared to its level in 1981.

We anticipate winter loads will grow at a faster rate than summer loads because electric space heating in the Vepco service area is expected to increase further from its current 25 percent to 34 percent in 1990. This is expected to produce a balance of winter and summer peaks by the mid-1980s. The balance in peaks will improve the load factor of our generating equipment. Load factor is the ratio of average use, during a specified time interval, to the peak use during the same interval.

Bath County and North Anna Unit 3

To meet part of the forecasted increase in demand, Vepco now has under construction the Bath County Pumped Storage Project, with 2.1 million kilowatts of capacity. If the agreement to sell part of the Bath County capacity to APS is approved (see Financial Support), Vepco's share will be 1.05 million to 1.26 million kilowatts.

The Bath County Project is now 60 percent complete. Three of six units are scheduled to go into service in late 1985, and the remaining three units in mid-1986. When it is completed, Bath County will be the world's most powerful pumped storage facility, and will give Vepco an economical means of meeting daily peaks in power demand.

Steel linings are being installed in tunnels which will carry water from upper to lower reservoirs at Bath County Pumped Storage Station.

Meeting Future Demand

The Company also is building North Anna Unit 3, its fifth nuclear unit. This unit is scheduled to go into service in 1989 with 907,000 kilowatts of capacity. Construction on the project, which was slowed in 1979 while the Company reassessed its entire construction program, will be reintensified in 1982. Construction of North Anna Unit 3 was approximately 8 percent complete by year's end, with work underway on major structural support systems for the basic foundation design.

During 1981, Vepco assumed project management responsibilities from the general contractors on the Bath County Project. Vepco had previously assumed these responsibilities on the North Anna Unit 3 Project in 1980. The Company also negotiated a new engineering and design services contract on North Anna Unit 3, which took effect on October 1, 1981. These steps will afford Vepco significantly increased flexibility and control over engineering as well as the construction of both projects.

With these two projects providing approximately 2 million kilowatts of additional capacity to the Vepco system by 1989, the Company will have the means to meet projected demand growth through 1991 with a reserve margin of about 25 percent.

However, the Company is faced with the decision of how best to meet the additional demand of almost 3 million kilowatts between 1992 and the end of the century.

Alternative Energy Sources

The Company initiated in November 1981 a 3-year study to compare a dozen non-conventional and two conventional means of meeting or reducing projected future growth in electricity demand.

The study will investigate the possibilities for increased conservation, load management and cogeneration. It also will evaluate the use of solar units in homes and businesses, low-head hydro, wind turbines, fuel cells, combined cycle systems, solar photovoltaic cells, and three non-conventional fuels: peat, municipal waste and wood.

These non-conventional options will be compared with each other, and with conventional coal and gas generation, to determine the lowest cost method of meeting projected demand. Because of the time required to build and license conventional generating stations, if they prove to be the best choice, the decision on how to proceed must be made no later than 1985.

These options include deliberate measures to reduce demand below the levels being forecast. Vepco already has conservation, load management and cogeneration programs that are expected to reduce 1989 power demand by more than 360,000 kilowatts.

Alternate Energy Study meeting including (left to right) W.L. Proffitt, G.C. Headley, W.N. Thomas, Irene M. Moszer, M.L. Brehmer and J.H. Ferguson (below left).

Reviewing construction of electrostatic precipitators at Chesterfield Power Station are (left to right) A.L. Parrish III, S.C. Brown, Jr. and W.C. Spencer.

In 1981, Vepco raised a total of $421.7 million in outside capital, including $181.0 million in term loans, $138.0 million in First and Refunding Mortgage Bonds, $47.3 million in Bath County Hydroelectric Trust Funds and $55.4 million of common stock sales and subscriptions, to finance its 1981 construction program. It also entered into agreements for the sale of portions of the Bath County Project and the North Anna Power Station, including North Anna Unit 3 which is now under construction. These sales would enable the Company to reduce substantially its future financing requirement

Bath County Project Sale

Vepco and APS signed an agreement in principle on June 19, 1981, for the sale of a portion of the Bath County Pumped Storage Project to APS. The agreement is subject to the approval of Federal and state regulatory agencies, which we hope to receive in 1982.

The Company agreed to sell 20 percent of the Bath County Project, and to sell or sell capacity of an additional 20 to 30 percent of the facility, to APS. Subject to obtaining necessary regulatory approvals, Vepco would receive about $190 million from APS for the 20 percent ownership interest. Subsequently, the Company would receive about $143 million from APS as reimbursement for future expenditures. If APS chooses to increase its interest in Bath County to 40 percent, Vepco's share of the project costs would be reduced by about an additional $300 million. All state regulatory approvals have been obtained except for Pennsylvania and Maryland. In Maryland, hearings have been completed and a decision is pending. In Pennsylvania, hearings on a show cause order are presently scheduled to begin in early March, but this schedule is in dispute. The Company cannot predict the outcome or timing of these proceedings, but would hope to close the sale later in 1982.

North Anna Sale

On October 21, 1981, after nearly 7 years of negotiation, Vepco agreed in principle to sell portions of its North Anna Power Station to Old Dominion Electric Cooperative.

The agreement calls for the cooperative to purchase 25 percent of North Anna Unit 2, 18 percent of North Anna Unit 3 which is now under construction, and 12.5 percent of the common facilities at the North Anna Power Sta-

Transmission lines span the Rappahannock River.

Financial Support

tion. Under terms of the agreement Old Dominion would pay Vepco approximately $300 million for existing facilities to be purchased by Old Dominion, if a mid-1982 target date for completing the agreement is met. Subsequently, Old Dominion would pay its proportionate share of the on-going construction costs of North Anna—about $500 million—as well as proportionate shares of operating and maintenance costs.

The final agreement is subject to approval by the Virginia State Corporation Commission, the West Virginia Public Service Commission, the Nuclear Regulatory Commission (NRC), the FERC and REA.

Stock Sales

Vepco sold 2 million shares of common stock on September 9, 1981, to a limited number of institutional investors represented by a single investment advisor. Proceeds to the Company were $22.3 million.

Customer Stock Purchase Plan

In September 1981, Vepco issued 544,163 shares of common stock valued at more than $6 million to more than 13,000 customers, who completed the first year (1980–81) of the Company's Customer Stock Purchase Plan. This unique installment purchase plan devised by Vepco in 1980 has been adopted by a number of other companies.

The plan permits Vepco customers to avoid brokerage fees and select the amount of their monthly installment payments, which can be as little as $10. More than 20,000 customers have enrolled in the 1981–82 plan.

Dividend Reinvestment Plan

The Administration's 1981 tax package includes several provisions that may be of long-term benefit to our stockholders and customers alike. For the individual stockholder, the new law provides an incentive to participate in automatic dividend reinvestment plans.

The first $750 of dividends ($1,500 if filing a joint return) received in the form of newly issued common stock from a qualified plan is not taxed as dividend income. Instead, the cost basis for the stock received from the reinvested dividends would be zero. When the stock, if held more than a year, is sold, the taxpayer would pay taxes at the capital gains rate. The change is effective for dividends paid after December 31, 1981.

Employee Relations

Vepco made important progress in improving employee relations during 1981. Several improvements and changes were implemented based on a Company-wide employee attitude survey and recommendations made by an employee task force in 1980.

To assist managerial development and improve supervisory skills, the Company increased supervisory training by 30 percent, with about 780 supervisors participating. In an effort to provide greater professional opportunities for employees, reduce costs and achieve a higher level of quality control, Vepco is reducing its use of consultants, especially in the engineering and construction area. Instead, it is assigning employees to work with consultants, and to take over the consultants' responsibilities when possible.

On March 20, 1981, Vepco became one of the first 10 companies to receive approval from the NRC of its Nuclear Security Personnel Training and Qualifications Plan. The plan, with more than 200 security personnel qualified, was put into effect 2 years ahead of a deadline set by the NRC.

Senior Staff meeting including (left to right) J.T. Rhodes, R.F. Hill, C.M. Jarvis, E.L. Crump, Jr., P.G. Edwards and B.D. Johnson (pictured above).

Discussing financing plans are (left to right) D.S. Brollier, L.R. Robertson, O.J. Peterson, III, S.B. Robertson, and J.R. Frazier, Jr.

Vepco established on October 2, 1981, a separate gas division to conduct its gas distribution operations in Tidewater Virginia, where it serves approximately 120,000 gas customers in the Norfolk-Newport News area. This service territory extends from Virginia Beach to Williamsburg.

The division's new name is Virginia Natural Gas, and by mid-1982 will have about 415 employees.

The new division reflects the Company's confidence in the continued growth of its gas business, and the corresponding need for managers and employees in the division to focus entirely on gas operations.

Prior to the reorganization, Vepco's gas and electric operations were managed jointly. While the reorganization will have no effect on gas rates in the short term, both customers and Vepco will benefit from the new structure in the long term.

Greater efficiency will be achieved in the gas business by a team of managers and employees concentrating solely on its operations. The restructuring will allow the development of greater expertise in this component of Vepco's business, especially among those employees who formerly had responsibility for both gas and electric operations. Inevitably, it will enable Vepco to provide even better service to its gas customers, and will lead to improved financial results for the Company by allowing more aggressive marketing of gas services.

The new division consists of two districts serving customers north and south of Hampton Roads. Vepco has purchased a 24-acre tract in Norfolk, as a site for the division headquarters, met shop and the Southern district office.

The Northern district operations will be based in a structure now under construction on a 13-acre site in Newport News. This building is scheduled fo completion by the late summer of 1982

Increased Sales

After a period of stagnation in the 1970s when gas was in short supply, the gas business now is entering a new period of growth. The 1978 Natural Gas Policy Act, which provided for eventual price deregulation of new natural gas by 1985, already has led to a major increase in supply. Gas industry forecasts predict demand, particularly in industrial and commercial

M.N. Early and E.C. Keeling inspect Virginia Natural Gas facilities.

Gas Operations

markets, could increase dramatically as a result of oil displacement and new industrial growth.

The emerging strength of Vepco's gas market was demonstrated in 1981 by the growth in Gas Division sales. Sales reached 19,738,000 mcf (thousand cubic feet), a 13 percent increase over 1980.

This growth was aided by the addition of Owens-Illinois Corp. to the division's list of customers during the year. Using 600,000 mcf annually, Owens-Illinois is now the division's largest firm customer. Anheuser-Busch, an already well-established customer, tripled its gas usage in 1981, making it the largest interruptible customer in the division system.

Total revenues amounted to $92.1 million in 1981, a 31 percent increase over 1980. Significant revenue increases were registered in all four of the division's customer classes: Residential (19 percent); Commercial-firm (30 percent); Industrial-firm (88 percent); and Interruptible (56 percent).

Yorktown Conversion

Vepco began conversion in 1981 of the Yorktown Power Station Unit 3 from an oil-fired unit to one which will burn a mixture of oil and gas. By the spring of 1982, 16 percent of this unit's fuel supply will be gas.

While the savings in fuel costs from this conversion will depend on future oil and gas prices, Vepco estimates that by converting Yorktown Unit 3 to a mixed oil-gas unit the Company will save customers $15 million in fuel costs in future years.

To accommodate the conversion, Vepco also began construction in 1981 of a 20-inch gas pipeline, which is scheduled for completion in the spring of 1982. When completed, the $3.5 million pipeline will run 8 miles from the Lee Hall section of Newport News to the Yorktown Power Station.

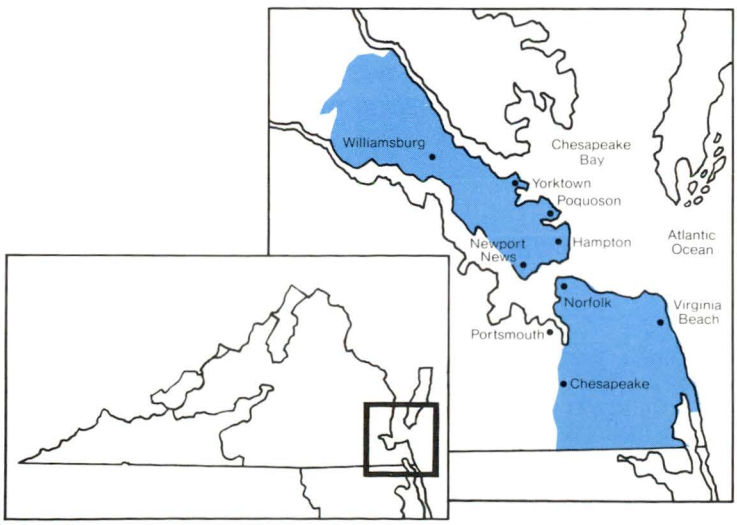
Rate Case Results

On June 30, 1981, the Company filed a request with the Virginia State Corporation Commission (SCC) for a 3.8 percent increase in gas revenue, or about $2.8 million on an annual basis. The increase was based on a test year ending March 31, 1981. The Company also requested an increase in the rate of return on common equity from 13.5 percent to 16.5 percent.

On November 16, 1981, the commission granted a $2 million increase in revenue effective November 23, 1981, or about 71 percent of the requested amount. The rate increase raised the monthly bill of a typical space heating customer 1 percent, from $76.52 to $77.30. The SCC increased Vepco's rate of return on common equity to 15 percent.

Virginia Natural Gas

Virginia Natural Gas Service Area



Virginia Natural Gas Operating Statistics

	Years				
	1981	1980	1979	1978	1977
Operating revenues (thousands):					
Residential	**$ 42,036**	$ 35,323	$ 29,380	$ 30,621	$ 26,640
Commercial and industrial	**49,539**	34,411	25,346	20,000	17,981
Other	**514**	522	655	418	302
Total gas operating revenues	**$ 92,089**	$ 70,256	$ 55,381	$ 51,039	$ 44,923
Population served at retail-estimated	**981,000**	971,000	875,000	875,000	875,000
Number of customers:					
Residential	**112,220**	111,164	109,902	110,390	111,188
Commercial and industrial-firm	**9,182**	8,885	8,718	8,861	9,035
Interruptible	**69**	59	36	37	39
Total gas customers	**121,471**	120,108	118,656	119,288	120,262
Sales—Mcf (thousands)	**19,738**	17,495	16,307	15,303	15,065
Output—Mcf manufactured (thousands)	**244**	57	74	236	650
Mcf natural gas purchased (thousands)	**20,755**	18,906	17,499	16,407	15,448
Miles of main	**2,123**	2,108	2,095	2,096	2,099

Maurice L. Gamell, M.N. Early and E.C. Keeling in Virginia Natural Gas Control Room.

Construction of Virginia Natural Gas pipeline will facilitate partial conversion to gas at the Yorktown Power Station.

1981 Financial Report

Virginia Electric and Power Company

Description of Business

The electric business of the Company is conducted in most of Virginia and in parts of North Carolina and West Virginia. In its service area it sells electricity to retail customers (including governmental agencies), and at wholesale to rural electric cooperatives and municipalities. A division of the Company (Virginia Natural Gas) provides gas service in the Norfolk-Newport News area (except Portsmouth) and in the area extending from Newport News to and including Williamsburg.

Selected Financial Data

	Millions of Dollars (except per share amounts)				
	1981	1980	1979	1978	1977
Operating revenues	**$2,162**	$2,120	$1,703	$1,465	$1,359
Operating income	**469**	390	316	305	265
Balance for common stock	**181**	184	141	150	142
Earnings per share of common stock	**1.77**	1.93	1.63	1.88	1.92
Dividends paid per share of common stock	**1.425**	1.40	1.38	1.30	1.24
Total assets	**7,058**	6,511	5,961	5,211	4,802
Net utility plant	**6,013**	5,586	5,229	4,686	4,305
Long-term debt and preferred stock subject to mandatory redemption	**3,487**	3,216	2,941	2,681	2,407

Management's Discussion and Analysis of Financial Condition and Results of Operations

LIQUIDITY. Since the Arab oil embargo in 1974, the Company has experienced internal cash generation below the desired levels. More recently, the substantial increases in the use of fossil fuels and replacement power for unanticipated nuclear unit outages and for the steam generator repairs to Surry Nuclear Units 1 and 2, delays in obtaining recovery of these increased costs in rates and increased financing costs have offset to some extent the effect of substantial rate increases.

As a result of several reductions in projected load growth, together with escalating construction costs, financing constraints upon the Company and regulatory constraints upon nuclear power, the Company has canceled three nuclear units and deferred in-service dates for one other nuclear unit and six pumped storage units since 1974. In spite of the cancellations and deferments, construction expenditures during this period have required substantial sales of securities.

Internal cash generation during 1982 will be affected not only by the availability of the Company's nuclear generating units and the cost of fossil fuel or replacement power, but also by the level of capital expenditures, the cost of funds to the Company to finance those expenditures, the outcome of rate proceedings and the possible consummation of plans to sell a portion of the Bath County Pumped Storage Project and North Anna Station (see Capital Resources below).

Liquidity for electric utilities like the Company, which have large amounts committed for construction projects, depends to a great extent on the ability to obtain outside funds, since charges to present customers are not designed to fund total construction costs for future generating capacity.

CAPITAL RESOURCES. The 1982 capital requirements result principally from the estimated $799 million of capital expenditures and $95 million of refunding and mandatory cash sinking fund obligations of long-term debt and Preferred Stock. The Company presently expects that approximately 56% of these capital requirements will be obtained from internal sources, about 21% from the sale of a portion of the Bath County Pumped Storage Project (discussed below) and the remainder will be financed through sales of securities of various types, with the long-term objective of achieving and maintaining capitalization ratios in the range of 52% long-term debt, 13% Preferred and Preference Stock and 35% Common Equity.

Capital expenditures are generally financed initially by sales of commercial paper. To support these borrowings the Company has available bank lines of credit amounting to $416 million.

Commercial paper is refunded by means of the sales of intermediate and long-term debt and equity securities; but an earnings limitation of the Mortgage would have permitted the issuance at December 31, 1981 of $607 million of additional Bonds assuming an interest rate of 16.5% for additional Bonds. Another earnings limitation would permit no additional shares of Preferred Stock to be issued.

The construction program and related expenditures and financing can continue to change as a result of, among other factors, higher than anticipated inflation, additional regulatory and environmental costs, further changes in the rate of growth in peak demand, licensing and construction delays, results of rate proceedings and the possible consummation of sales of certain facilities.

On October 21, 1981, the Company agreed in principle with Old Dominion Electric Cooperative (ODEC) on the major terms of an arrangement for the purchase by ODEC of an ownership interest of 25% in North Anna Unit 2, 18% in North Anna Unit 3 and 12.5% in common facilities. The members of ODEC participating in this purchase arrangement are 12 Virginia cooperatives served by the Company at wholesale. The purchase is subject to the negotiation and execution of definitive agreements and to the receipt of required regulatory approvals. If definitive agreements can be reached and the necessary approvals are granted in 1982, the Company would receive approximately $300 million for existing facilities, and ODEC would pay its proportionate share of future costs of the North Anna Station. No assurance can be given that negotiations will be completed and the necessary regulatory approvals obtained.

The Company and Allegheny Power System, Inc. (APS) have signed agreements for sale of a part of the Bath County

Pumped Storage Project ($762 million invested through December 31, 1981). Under the agreements, APS is to purchase first an undivided interest of approximately 20% in the Project. APS is to fulfill the remainder of its 40% obligation through further purchases of undivided interests in the Project or through a capacity purchase agreement. Also, APS will be entitled to increase its 40% obligation up to 50% before December 31, 1984.

The agreements are subject to receipt of required regulatory approvals. After obtaining those approvals, the agreements provide for APS to pay approximately 20% of the Project's cost incurred through a closing date (anticipated to be during the first quarter of 1982) and to continue to pay approximately 20% of ongoing construction costs through part of 1984 (based on the present construction schedule). If the total Project costs exceed the present estimate, APS would not be obligated to pay for any portion of the excess, but if APS does not pay its proportionate share of such excess costs, its ownership interest would be correspondingly reduced. The Company estimates that it will receive about $190 million in cash for the acquisition by APS of an approximate 20% ownership interest, calculated on the basis of a first quarter 1982 closing. The Company would receive additional cash reimbursements for future expenditures, a reduction in its capital requirements or a combination of both, in the amount of about $143 million for APS's acquisition of this 20% ownership interest. In addition, if APS elects to increase its ownership interest to 40%, the Company's share of the Project costs would be reduced by about an additional $300 million.

If the necessary regulatory approvals are not received in order to consummate the sale as planned, the Company may reduce its capital expenditures for 1982, including Project expenditures, or obtain additional financing, or a combination of the foregoing, to cover any delay in receipt or failure to receive the proceeds from the sale to APS. If Project expenditures scheduled for 1982 were significantly reduced, the in-service dates for the Project would likely be deferred. A deferral for one year in the in-service dates for the Project (total cost presently estimated at $1.7 billion) could result in additional Project costs of $300 million or more.

RESULTS OF OPERATIONS. Due to the effects of inflation, delays in obtaining a nuclear unit license, unscheduled outages of nuclear and coal fired units, rapidly escalating costs of oil, major maintenance and repairs at most of the fossil units, increased depreciation and maintenance associated with additional power station units placed in service and increased costs of capital and capital expenditures, expenses have risen substantially during the past several years, and as a result, the Company has been granted substantial rate increases during these years.

After giving effect to the adjustments discussed in Note N to Financial Statements for the reduction in the provision for Federal income taxes resulting from the refund made to FERC jurisdictional customers and the refinement in the Company's method of amortizing investment tax credits, the balance for Common Stock decreased $3.7 million from 1980 to 1981. The decrease reflects the loss of allowance for funds used during construction ("AFC") due to the cancellation of North Anna Unit 4 and the impact of inflation on operating and financing costs offset, in part, by additional revenues from rate increases, increased sales, decreased fuel costs and the termination of certain customers' contracts as discussed in Note N to Financial Statements.

Electric revenues changed from 1979 through 1981 principally as a result of the following:

	Revenues Increase (Decrease) From Prior Year (Millions of Dollars)	
	1981	1980
Rate increases and fuel cost recovery	**$(16.1)**	$321.2
Unit sales (excluding effect of above)	**35.2**	76.8
Other, net	**1.1**	3.6
Total	**$20.2**	$401.6

Gas Revenues represent about 4.3% of total revenues. In 1981 the Company established Virginia Natural Gas, a new Gas Division. With the Company again permitted to connect new gas customers, substantial numbers of residential and significant industrial customers have been added. As a result of increased sales to customers and deregulation of natural gas pricing, gas revenues should continue to increase in the future but not to a level that would be significant compared to electric operations.

Fuel and purchased and interchanged power expenses have fluctuated from 1979 through 1981 as a result of changes in fuel costs, increased sales and the availability of coal-fired generation purchased from neighboring utilities at a cost less than the Company's oil-fired generation. The average cost of fuel consumed per kilowatt-hour generated is shown below:

	Mills Per Kilowatt-hour		
	1981	1980	1979
Nuclear	**6.52**	8.09*	5.27
Coal—Mt. Storm (mine-mouth)	**21.80**	17.16	13.80
—Other	**22.18**	20.36	20.61
Oil	**57.31**	44.73	31.45
Total System	**17.77**	21.76	20.44

* Includes generation at North Anna Unit 2 priced at the cost of displaced fuel during preliminary operations. Actual costs were 6.19 mills per kilowatt-hour.

Kilowatt-hour output by energy source is shown below:

	1981	1980	1979
Nuclear	**41%**	27%	17%
Coal—Mt. Storm (mine-mouth)	**13**	13	17
—Other	**18**	12	10
Oil	**8**	19	33
Purchased and interchanged	**19**	27	19
Other	**1**	2	4
	100%	100%	100%

The Company plans to convert most of its oil-fired generation to coal by the end of 1986. The Company has retired certain older and less efficient units (Chesterfield Units 1 & 2) and has placed 4 oil-fired units aggregating 474 Mw, in a non-operating cold reserve status and plans to convert these to coal.

Maintenance and depreciation expenses have increased since 1979 principally as a result of the addition of North Anna Unit 2 in December 1980, the Company's program for improvement of generating unit capability, and increased costs for labor and materials.

For information with respect to *Federal income and other taxes* see Notes B and D to Financial Statements.

Continuation of the Company's capital expenditures and the related financing together with increases in construction and nuclear fuel costs and changes in internally generated funds and costs of capital have resulted in increases in the amounts of *interest charges*.

AFC for other (equity) funds decreased in 1981 principally as a result of the cancellation of construction of North Anna Unit 4 in November 1980 and of the placing in service of North Anna Unit 2 in December 1980. As a result of approval by the Virginia Commission to discontinue AFC for Virginia jurisdictional customers on all new projects commenced after September 1, 1981 and to discontinue AFC on all expenditures for North Anna Unit 3 after that date, the amounts accrued in future years should decline further. These reductions of AFC have been reflected in increased Virginia jurisdictional rates.

AFC for borrowed funds did not decrease in 1981 because of the effect of the Bath County Project Financing. Decreases in the accrual of AFC-borrowed in future years as a result of the discontinuance of AFC applicable to Virginia jurisdictional customers will be offset to some extent by this project financing, depending on the amounts and cost of borrowings.

INFLATION. From the mid 1940's until the early 1970's customer demand increased so rapidly that the cost per kilowatt-hour to the customer declined. With the persistent high rates of inflation and rapid rises in oil costs during the 1970's, and significant decrease in the rate of growth of demand, the Company has required substantial amounts of rate relief including increases in fuel cost recovery billings.

An estimate of the effect of inflation measured by constant dollar accounting and current cost accounting for selected financial data is presented in Note O to Financial Statements.

Report of Management

The management of Virginia Electric and Power Company is responsible for all information and representations contained in the financial statements and other sections of the annual report. The financial statements, which include amounts based on estimates and judgments of management, have been prepared in conformity with generally accepted accounting principles. Other financial information in the annual report is consistent with that in the financial statements.

Management maintains a system of internal accounting control designed to provide reasonable assurance at a reasonable cost that the Company's assets are safeguarded against loss from unauthorized use or disposition and that transactions are executed and recorded in accordance with established procedures. This system includes written policies, an organizational structure designed to ensure appropriate division of responsibilities, careful selection and training of qualified personnel and a program of internal audits.

The financial statements have been examined by Coopers & Lybrand, independent certified public accountants. Their examination is conducted in accordance with generally accepted auditing standards and includes a review of the Company's accounting systems, procedures and internal controls, and the performance of tests and other auditing procedures sufficient to provide reasonable assurance that the financial statements neither are materially misleading nor contain material errors.

The Audit Committee of the Board of Directors, composed entirely of directors who are not officers or employees of the Company, meets periodically with the independent auditors, the executive manager-internal auditing and management to discuss auditing, internal accounting control and financial reporting matters and to ensure that each is properly discharging its responsibilities. Both the independent auditors and the executive manager-internal auditing periodically meet alone with the Audit Committee and have free access to the Committee at any time.

VIRGINIA ELECTRIC AND POWER COMPANY

Report of Independent Certified Public Accountants

To the Stockholders and Board of Directors of Virginia Electric and Power Company:

We have examined the balance sheets of Virginia Electric and Power Company as of December 31, 1981 and 1980, and the related statements of income, earnings reinvested in business and changes in financial position for each of the five years in the period ended December 31, 1981. Our examinations were made in accordance with generally accepted auditing standards and, accordingly, included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

In our opinion, the financial statements referred to above present fairly the financial position of Virginia Electric and Power Company as of December 31, 1981 and 1980, and the results of its operations and the changes in its financial position for each of the five years in the period ended December 31, 1981, in conformity with generally accepted accounting principles applied on a consistent basis.

Coopers & Lybrand

New York, New York
February 3, 1982

COOPERS & LYBRAND

Virginia Electric and Power Company
Statements of Income

	Years				
	1981	1980	1979	1978	1977
	(Thousands of Dollars)				
Operating revenues (Notes A and K)					
Electric	**$2,069,764**	$2,049,518	$1,647,928	$1,413,866	$1,313,937
Gas	**92,089**	70,256	55,381	51,039	44,923
Total	**2,161,853**	2,119,774	1,703,309	1,464,905	1,358,860
Operating expenses:					
Operation:					
Fuel used in electric generation (Notes A and E)	**555,466**	674,996	559,998	585,625	575,151
Purchased and interchanged power	**289,558**	341,011	194,547	9,384	52,273
Other (Note E)	**309,147**	250,848	210,840	183,906	153,514
Maintenance (Note A)	**138,147**	123,962	103,856	90,317	69,885
Depreciation (Notes A and F)	**174,120**	145,032	136,280	117,481	98,527
Amortization of abandoned project costs (Note C)	**12,203**	6,933	7,292	6,760	3,173
Taxes—Federal income (Notes A and B)	**93,669**	70,004	69,744	72,658	59,736
—Other (Note D)	**120,911**	117,456	104,358	93,499	81,174
Total	**1,693,221**	1,730,242	1,386,915	1,159,630	1,093,433
Operating income	**468,632**	389,532	316,394	305,275	265,427
Other income:					
Allowance for other funds used during construction (Note A)	**44,264**	73,206	66,603	64,002	72,361
Miscellaneous, net (Note N)	**16,236**	2,973	1,282	2,209	(305)
Income taxes associated with miscellaneous, net	**(7,607)**	(550)	(308)	(867)	(358)
Total	**52,893**	75,629	67,577	65,344	71,698
Income before interest charges	**521,525**	465,161	383,971	370,619	337,125
Interest charges:					
Interest on long-term debt	**280,012**	234,561	204,392	184,947	168,885
Other	**44,276**	28,530	12,417	6,677	5,748
Allowance for borrowed funds used during construction (Note A)	**(40,543)**	(39,550)	(29,305)	(24,869)	(27,301)
Total	**283,745**	223,541	187,504	166,755	147,332
Net income	**237,780**	241,620	196,467	203,864	189,793
Preferred and preference dividends	**57,166**	57,291	55,123	53,588	47,719
Balance for common stock	**$ 180,614**	$ 184,329	$ 141,344	$ 150,276	$ 142,074
Shares of common stock—average for year (thousands)	**101,856**	95,520	86,965	80,060	74,025
Earnings per share of common stock	**$1.77**	$1.93	$1.63	$1.88	$1.92
Cash dividends paid per common share	**$1.425**	$1.40	$1.38	$1.30	$1.24

( ) Denotes red figure.
The accompanying notes are an integral part of the financial statements.

Virginia Electric and Power Company
Balance Sheets

Assets

		December 31, 1981		December 31, 1980
		(Thousands of Dollars)		
UTILITY PLANT (Note A):				
Electric		**$7,032,549**		$6,445,405
Gas		**75,949**		66,289
Common		**22,918**		16,892
Total (includes $1,618,880,000 plant under construction [1980—$1,451,292,000]).		**7,131,416**		6,528,586
Less accumulated depreciation (Note F)		**1,263,867**		1,118,308
		5,867,549		5,410,278
Nuclear fuel (less accumulated amortization of $210,879,000 [1980—$131,321,000])		**145,339**		176,187
Net utility plant		**6,012,888**		5,586,465
INVESTMENTS:				
Nonutility property at cost or written-down amounts (less allowance of $7,657,000 [1980—$7,546,000])		**5,472**		6,327
Subsidiary companies at equity (includes advances of $14,758,000 [1980—$13,659,000])(Notes A and M)		**21,282**		19,851
Net investments		**26,754**		26,178
CURRENT ASSETS:				
Cash (Note I)		**16,669**		26,290
Temporary cash investments				8,500
Accounts receivable:				
Customers	**$186,665**		$181,745	
Other	**25,560**		20,050	
	212,225		201,795	
Less allowance for doubtful accounts	**2,002**	**210,223**	1,360	200,435
Accrued unbilled revenues		**93,551**		83,123
Materials and supplies at average cost or less:				
Plant and general (including construction materials)	**76,924**		55,515	
Fossil fuel	**129,557**	**206,481**	130,203	185,718
Prepayments:				
Taxes	**28,964**		32,959	
Other	**18,712**	**47,676**	11,806	44,765
Total current assets		**574,600**		548,831
DEFERRED DEBITS:				
Abandoned project costs (less accumulated amortization of $36,361,000 [1980—$24,158,000])(Note C)		**193,112**		172,720
Deferred fuel costs (Note A)		**137,000**		78,104
Deferred interest charges (Note A)		**22,740**		19,818
Pollution control project funds		**37,667**		45,570
Unamortized expense on debt		**8,971**		8,754
Other		**44,099**		25,053
Total deferred debits		**443,589**		350,019
		$7,057,831		$6,511,493

The accompanying notes are an integral part of the financial statements.

Capital and Liabilities

	December 31, 1981	December 31, 1980
	(Thousands of Dollars)	
PREFERRED STOCK SUBJECT TO MANDATORY REDEMPTION—		
$100 par, cumulative (Note G)	**$ 326,927**	$ 328,911
PREFERRED STOCK NOT SUBJECT TO MANDATORY REDEMPTION—		
$100 par, cumulative (Note H)	**289,014**	289,014
PREFERENCE STOCK NOT SUBJECT TO MANDATORY REDEMPTION—		
no par, cumulative; authorized 30,000,000 shares (Note H)	**57,360**	57,360
COMMON STOCKHOLDERS' EQUITY (Note H):		
Common stock—no par	**1,457,072**	1,400,874
Other paid-in capital	**24,516**	25,352
Earnings reinvested in business, as annexed	**470,888**	435,430
Total common stockholders' equity	**1,952,476**	1,861,656
LONG-TERM DEBT (Note J)	**3,160,014**	2,887,114
CURRENT LIABILITIES:		
Securities due within one year (Notes G and J)	**94,983**	124,276
Loans payable, pending permanent financing (Note I)	**164,938**	83,721
Accounts payable, trade	**87,742**	111,674
Customer deposits	**14,424**	11,884
Payrolls accrued	**16,611**	13,498
Taxes accrued	**74,730**	53,606
Interest accrued	**83,192**	76,501
Deferred income taxes (Notes A and B)	**14,313**	14,856
Other	**89,263**	80,826
Total current liabilities	**640,196**	570,842
DEFERRED CREDITS:		
Uranium settlement (Note M)	**160,914**	142,172
Accumulated deferred income taxes (Notes A and B):		
Liberalized depreciation	**203,714**	149,867
Abandoned project costs	**73,384**	63,514
Other	**34,591**	26,040
Deferred investment tax credits (Notes A and B)	**109,647**	106,808
Other (Note E)	**49,594**	28,195
Total deferred credits	**631,844**	516,596
COMMITMENTS AND CONTINGENCIES (Note M)		
	$7,057,831	$6,511,493

Virginia Electric and Power Company
Statements of Earnings Reinvested in Business

	Years				
	1981	1980	1979	1978	1977
	(Thousands of Dollars)				
Balance at beginning of year	**$435,430**	$384,600	$364,215	$318,507	$328,115
Net income (see "Statements of Income")	**237,780**	241,620	196,467	203,864	189,793
Total	**673,210**	626,220	560,682	522,371	517,908
Cash dividends:					
Preferred stock subject to mandatory redemption:					
$7.325 preferred	**5,128**	5,128	5,128	5,128	5,128
$8.40 preferred	**6,720**	6,720	6,720	6,720	6,720
$9.125 preferred	**1,807**	1,825	1,825	1,825	1,825
$8.20 preferred	**4,920**	4,920	4,920	4,920	1,134
$8.60 preferred	**3,087**	3,189	3,291	3,392	
$8.625 preferred	**3,191**	3,191	3,191	1,785	
$8.925 preferred	**2,499**	2,499	153		
Preferred stock not subject to mandatory redemption:					
$5.00 preferred	**533**	533	533	533	1,447
$4.04 preferred	**52**	52	52	52	404
$4.20 preferred	**62**	62	62	62	420
$4.12 preferred	**134**	134	134	134	515
$4.80 preferred	**351**	351	351	351	1,440
$7.72 preferred	**2,702**	2,702	2,702	2,702	2,702
$8.84 preferred	**3,094**	3,094	3,094	3,094	3,094
$7.45 preferred	**2,980**	2,980	2,980	2,980	2,980
$7.20 preferred	**3,240**	3,240	3,240	3,240	3,240
$7.72 preferred (1972 Series)	**3,860**	3,860	3,860	3,860	3,860
$9.75 preferred	**5,850**	5,850	5,850	5,850	5,850
Preference stock not subject to mandatory redemption:					
$2.90 preference	**6,960**	6,960	6,960	6,960	6,960
Common stock	**144,937**	133,005	120,638	103,474	91,225
Total dividends	**202,107**	190,295	175,684	157,062	138,944
Transfer to common stock as authorized by Board of Directors					60,000
Other deductions, net	**215**	495	398	1,094	457
Total	**215**	495	398	1,094	60,457
Balance at end of year	**$470,888**	$435,430	$384,600	$364,215	$318,507

The accompanying notes are an integral part of the financial statements.

Virginia Electric and Power Company
Statements of Changes in Financial Position

	Years				
	1981	1980	1979	1978	1977
	(Thousands of Dollars)				
SOURCE OF FUNDS:					
Funds provided by operations:					
Net income	**$ 237,780**	$241,620	$ 196,467	$203,864	$189,793
Items not affecting working capital:					
Provision for depreciation (Notes A and F)	**174,120**	145,032	136,280	117,481	98,527
Amortization of nuclear fuel (Note A)	**79,558**	52,170	25,576	29,702	14,526
Amortization of abandoned project costs (Note C)	**12,203**	6,933	7,292	6,760	3,173
Allowance for other funds used during construction (Note A)	**(44,264)**	(73,206)	(66,603)	(64,002)	(72,361)
Allowance for borrowed funds used during construction (Note A)	**(40,543)**	(39,550)	(29,305)	(24,869)	(27,301)
Deferred income taxes (Notes A and B)	**72,226**	52,177	66,545	14,668	31,536
Deferred investment tax credits, net (Notes A and B)	**6,711**	6,627	(5,250)	34,827	19,009
Total funds provided by operations	**497,791**	391,803	331,002	318,431	256,902
Funds provided by financing and other sources:					
Mortgage bonds (Note J)	**138,000**	75,000	235,000	213,000	150,000
Preferred stock subject to mandatory redemption (Note G)			28,000	37,000	60,000
Common stock (Note H):					
Public offering	**22,290**	53,950	64,050	68,275	70,400
Automatic dividend reinvestment plan	**18,387**	16,379	12,926	11,690	9,229
Employee savings plan and TRASOP	**7,975**	6,261	7,222	4,774	4,213
Customer stock purchase plan subscriptions	**6,701**	2,474			
Bath County hydroelectric trust (Note J)	**47,340**	201,810			
Term notes (Note J)	**181,000**	125,000	60,000	104,750	108,500
Pollution control project funds	**7,903**	(37,734)	3,914	(8,019)	(721)
Increase (decrease) in loans payable	**81,217**	(48,009)	128,293	(49,613)	26,550
Uranium settlement (Note M)	**18,742**	11,826	130,346		
Total funds provided by financing and other sources	**529,555**	406,957	669,751	381,857	428,171
	$1,027,346	$798,760	$1,000,753	$700,288	$685,073
APPLICATION OF FUNDS:					
Utility plant expenditures (excluding AFC)	**$ 542,331**	$536,049	$ 551,881	$422,857	$394,875
Nuclear fuel (excluding AFC)	**49,157**	32,315	60,967	17,458	74,531
Abandoned project costs (Note C)	**32,595**	1,332	(2,542)	2,631	16,050
Dividends on common, preferred and preference stocks	**202,107**	190,295	175,684	157,062	138,944
Increase (decrease) in deferred fuel costs (Note A)	**58,896**	(11,146)	85,867	(29,898)	(18,812)
Increase (decrease) in deferred interest charges (Note A)	**2,922**	5,357	11,907	2,553	(3,078)
Securities reacquired or repaid	**124,276**	65,300	74,883	97,273	58,250
Increase (decrease) in investment (net of repayment of advances) in subsidiary companies (Notes A and M)	**1,431**	(372)	797	4,345	3,137
Increase (decrease) in working capital other than loans payable*	**8,339**	(31,757)	42,136	36,551	14,684
Other, net	**5,292**	11,387	(827)	(10,544)	6,492
	$1,027,346	$798,760	$1,000,753	$700,288	$685,073
Changes in the individual amounts comprising working capital other than loans payable* were as follows:					
Accounts receivable	**$ 9,788**	$ 38,537	$ 33,842	$ 17,215	$ 1,687
Uranium settlement (Note M)		(41,000)	41,000		
Accrued unbilled revenues	**10,428**	(10,679)	32,395	(2,523)	4,965
Materials and supplies	**20,763**	14,047	42,675	7,284	26,392
Accounts payable, trade	**23,932**	16,010	(73,271)	19,350	1,775
Taxes accrued	**(21,124)**	(27,843)	8,027	(20,426)	(4,842)
Interest accrued	**(6,691)**	(7,217)	(4,633)	(11,388)	(6,916)
Deferred income taxes (Notes A and B)	**543**	2,460	1,464	4,657	(2,537)
Other, net	**(29,300)**	(16,072)	(39,363)	22,382	(5,840)
	$ 8,339	$ (31,757)	$ 42,136	$ 36,551	$ 14,684

* Does not include reclassification as current liabilities of maturing long-term debt and cash sinking fund obligations of debt and preferred stock as follows: 1981—$94,983,000; 1980—$124,276,000; 1979—$62,093,000; 1978—$75,293,000; and 1977—$89,433,000.

The accompanying notes are an integral part of the financial statements.

Notes to Financial Statements

A. Significant Accounting Policies:

General:

The Company's accounting practices are prescribed by the Uniform Systems of Accounts promulgated by the regulatory commissions having jurisdiction.

Revenues:

Operating revenues are recorded on the basis of service rendered.

Utility Plant and Depreciation:

Utility plant is recorded at original cost which includes labor, materials, services, allowance for funds used during construction and other indirect costs. The cost of depreciable utility plant retired and cost of removal, less salvage, are charged to accumulated depreciation.

The cost of maintenance and repairs is charged to the appropriate operating expense and clearing accounts. The cost of renewals and betterments is charged to the appropriate utility plant account, except the cost of minor replacements which is charged to maintenance expense.

The present value of estimated decommissioning costs of $134,624,000 for nuclear units in service (assuming mothballing) is being charged to customers subject to the jurisdiction of the Virginia Commission. For the remaining jurisdictions, estimated decommissioning costs are being recorded on the straight-line depreciation method based upon estimated service lives.

Nuclear Fuel:

Progress payments are being made for fuel to be owned or leased.

Amortization of owned nuclear fuel is provided on a unit of production basis sufficient to amortize the cost over the estimated service life. Effective in 1978, the North Carolina Commission granted approval to recover the cost of permanent storage of spent fuel in base rates and the Federal Energy Regulatory Commission (FERC) allowed the recovery of these costs through the fuel clause. For periods subsequent to these two decisions, operating expenses include reprocessing costs for Virginia jurisdictional customers, permanent storage costs for North Carolina jurisdictional customers and projection of interim storage costs only for FERC jurisdictional customers.

Subsidiaries:

The Company has two wholly-owned subsidiaries. Laurel Run Mining Company is engaged in the underground mining of coal, which is utilized solely by the Company. Virginia Nuclear, Inc. was organized to explore for uranium reserves; however, no such activities are presently being conducted.

Federal Income Taxes:

The Company's practice is to reduce the current provision for Federal income taxes to reflect the tax benefit resulting from the use of the double-declining-balance method of depreciation for property additions, the adoption of the Asset Depreciation Range and Class Life Systems, and the adoption of the Accelerated Cost Recovery System. Effective with property additions placed in service in 1974, the Company has provided deferred income taxes on the aforementioned benefit and, subsequently, has provided deferred taxes on other differences between book income and income taxable for Federal income taxes to the extent permitted by the regulatory commissions having jurisdiction.

Investment Tax Credits:

Accumulated investment tax credits are being amortized over the service lives of the property giving rise to such credits. An additional investment tax credit of 1% related to the Tax Reduction Act Stock Ownership Plan (TRASOP) does not affect net income and is recorded as a liability until the contribution is made to the TRASOP trust.

Allowance for Funds Used During Construction:

The applicable regulatory Uniform Systems of Accounts defines AFC as the net cost for the period of construction of borrowed funds used for construction purposes and a reasonable rate on other funds when so used.

The Company separately determines rates and reports amounts applicable to borrowed funds, calculated on a net of tax basis, and to equity funds. In accordance therewith, for 1981, 1980, 1979, 1978 and 1977, aggregate rates of 8.06%, 7.79%, 7.80%, 7.54% and 7.75%, respectively, were employed for the accrual of AFC.

For expenditures on the Bath County Pumped Storage Project after December 31, 1979, AFC is being accrued in an amount equal to the net of tax cost of borrowings associated with the Project Financing.

In August 1981, the Virginia Commission granted rate relief of $131.8 million that included the Company's proposal to eliminate AFC on additional construction expenditures for North Anna 3 and on all new projects commencing after September 1, 1981.

Deferred Fuel Costs:

The Company is deferring for accounting and rate-making purposes that portion of the cost of fuel consumed which, through the application of the annual fuel factor, may result in increased operating revenues in a later period. In the event that future developments dictate a change in the fuel adjustment billing lag period or in the fuel cost base, the Company will request regulatory approval to recover through billings to customers any unrecovered deferred fuel costs.

Deferred Interest Costs:

The Company charges to operations an interest cost associated with variable interest rate loans based on the interest rate ceiling stated in the loan agreements. Amounts paid in excess of the amounts charged to operations are deferred pending refund from the applicable lending institutions.

Retirement Annuity Plan:

The Company has a contributory retirement annuity plan and funds pension costs accrued. Prior service cost arising out of amendments to the plan in 1979 and changes in actuarial assumptions in 1977 are being provided in the accounts and funded on the basis of future salaries of participants currently covered by the plan.

Leases:

The Company's practice is to account for all leases as operating leases in accordance with the rate-making practices presently in effect.

Reclassification:

Certain amounts in the 1980 financial statements have been reclassified to conform to the 1981 presentation.

B. Federal Income Taxes:

Details of Federal income taxes were as follows:

	Years				
	1981	1980	1979	1978	1977
	(Thousands of Dollars)				
Computed tax expense on book income before Federal income taxes at statutory rate	**$155,966**	$143,600	$122,599	$133,147	$119,946
(Decreases) increases resulting from:					
Excess of tax over book depreciation	**(14,354)**	(12,982)	(4,301)	(16,402)	(9,956)
AFC	**(39,011)**	(51,868)	(44,118)	(42,658)	(47,838)
Investment tax credits, amortization*	**(8,843)**	(5,171)	(5,820)	(5,467)	(4,539)
Other, net*	**(89)**	(3,575)	1,384	4,038	2,123
	(62,297)	(73,596)	(52,855)	(60,489)	(60,210)
Federal income tax expense	**$ 93,669**	$ 70,004	$ 69,744	$ 72,658	$ 59,736
Currently payable	**$ 14,732**	$ 11,200	$ 8,449	$ 23,163	$ 9,191
Tax effects of timing differences:					
Abandoned project costs	**9,870**	38,582	(4,421)	(1,822)	31,175
Fuel related items:					
Current year deferred fuel adjustment	**19,149**	(19,087)	47,054	(21,681)	(9,588)
Reprocessing/disposal costs on nuclear fuel	**(13,063)**	(7,988)	(8,067)	(6,791)	(6,385)
Fuel expense nuclear plant testing	**(2,410)**	(3,663)			
Nuclear fuel—owned	**5,572**	(2,669)	(4,452)	(487)	
Liberalized depreciation	**53,847**	41,108	32,418	38,509	13,101
Virginia gross receipts taxes	**(1,429)**	(2,460)	(1,464)	636	2,375
Nuclear decommissioning costs	**(994)**	(764)			
Spare parts inventory adjustment	**(3,117)**	4,120			
Accelerated amortization	**(1,547)**	(1,547)	(1,547)	(1,547)	(1,547)
Indirect construction costs	**2,310**	2,800	3,463	3,154	2,912
Cost of removal of property retirements	**2,057**	3,729	3,545	2,484	1,696
Customer accounts reserve	**(812)**				
Variable prime interest	**2,293**				
Contributions in aid of construction				2,203	(2,203)
Other	**500**	16	16	10	
	72,226	52,177	66,545	14,668	31,536
Investment tax credits	**15,554**	11,798	570	40,294	23,548
Investment tax credits, amortization*	**(8,843)**	(5,171)	(5,820)	(5,467)	(4,539)
Net deferred investment tax credits	**6,711**	6,627	(5,250)	34,827	19,009
Federal income tax expense	**$ 93,669**	$ 70,004	$ 69,744	$ 72,658	$ 59,736

*See Note N to Financial Statements for the effects on the 1981 provision for Federal income taxes of a rate refund and a change in amortization of investment tax credits applicable to nuclear fuel.

The Company has investment tax credit carry-forwards of $137,374,000, of which $6,885,000, $18,870,000, $63,372,000 and $48,247,000 will expire, unless used, in 1993, 1994, 1995, and 1996 respectively.

C. Abandoned Project Costs:

In March 1977, the Company canceled the construction of Surry Units 3 and 4, for which $98.2 million was expended at December 31, 1981. The Company amortizes such costs, net of Federal income taxes, over a ten-year period as incurred, for accounting and rate-making purposes.

In November 1980, the Company canceled the construction of North Anna Unit 4 due primarily to reduced load growth projections, high financing costs, the uncertainty surrounding the regulation of nuclear power and the Company's load management programs which are estimated to result in a delay of additional generating capacity requirements. Expenditures at December 31, 1981 amounted to $127.7 million net of transfers of certain parts and equipment to other projects. After additional costs which may be incurred, the loss is presently estimated to be $154.5 million. The Virginia and North Carolina Commissions approved the recovery of cancellation costs in base rates over a ten-year period, effective in August 1981 and October 1981 respectively. Additionally, the North Carolina Commission permitted the inclusion of the unamortized balance of such costs in rate base. The Company has requested similar rate-making treatment from the West Virginia Commission and the FERC.

D. Supplementary Income Statement Information:

The amounts of royalties, advertising costs and research and development costs were not significant. Taxes other than Federal income taxes charged to expenses were as follows:

	Years				
	1981	1980	1979	1978	1977
	(Thousands of Dollars)				
Taxes, other than Federal income taxes:					
Real estate and property	**$ 33,577**	$ 29,182	$ 28,462	$26,333	$25,257
State and local gross receipts	**65,750**	71,838	60,934	54,865	49,812
State income	**47**	162	57	505	248
Other	**21,537**	16,274	14,905	11,796	5,857
Total	**$120,911**	$117,456	$104,358	$93,499	$81,174

E. Leases:

Rents charged to expenses consisted of the following:

	Years				
	1981	1980	1979	1978	1977
	(Thousands of Dollars)				
Operating leases:					
Nuclear fuel	**$38,989**	$21,140	$11,632	$35,491	$29,518
Combustion turbines	**5,451**	5,524	5,611	5,694	5,935
Other (principally buildings and teleprocessing equipment)	**10,771**	11,206	10,583	8,427	6,648
Total	**$55,211**	$37,870	$27,826	$49,612	$42,101

In 1971, the Company sold and leased back 28 combustion turbines for a term of 20 years (plus two optional five-year renewal terms). Annual rental payments are $6,444,000 during the second ten year term. Additional rentals were accrued during the first ten years when payments represented only interest, so that the annual effect on net income would be equalized over the twenty-year period. Deferred credits other, at December 31, 1981, include $19,828,000 with regard to such accruals. Had the lease been capitalized, the net asset value and present value of the lease commitment would be $20,591,000 and $42,601,000, respectively, at December 31, 1981 and $22,721,000 and $42,601,000, respectively, at December 31, 1980.

The Company has heat supply contracts for the nuclear fuel for Surry Units 1 and 2 providing for an aggregate commitment of $110 million at December 31, 1981. Quarterly payments are charged to income in amounts sufficient to pay for the fuel burned during each quarter (excluding reprocessing and permanent disposal costs) plus interest. Had the contracts been capitalized, the net asset value and present value of these commitments would be $98,930,000 and $101,822,000, respectively, at December 31, 1981 and $99,118,000 and $102,398,000, respectively, at December 31, 1980.

In 1974, the Company sold and leased back three office buildings for terms of twenty years (plus two optional five-year renewal terms). Annual rental payments are $730,000 during the initial terms of the leases. In 1978, the Company leased a newly constructed headquarters office building for a term of thirty years (plus four optional five-year renewal terms). Annual rental payments are $2,993,000 during the initial term of the lease. Had the leases been capitalized, the net asset value and present value of the lease commitments would be $35,565,000 and $39,490,000, respectively, at December 31, 1981 and $37,087,000 and $40,106,000, respectively, at December 31, 1980.

If the Company had capitalized the above noted leases and contracts, the increase in operating expenses would not have been material.

The Company is responsible for expenses in connection with the leased turbines, nuclear fuel and buildings noted above, including insurance, taxes and maintenance.

F. Depreciation:

The provision for depreciation based on mean depreciable plant has been as follows:

	Electric	Gas	Common
1981	3.3%	3.1%	4.1%
1980	3.3	3.1	4.0
1979	3.3	3.1	4.4
1978	3.2	3.1	2.4
1977	3.1	2.6	2.3

G. Preferred Stock Subject to Mandatory Redemption:

Preferred Stock subject to mandatory redemption was represented by 3,289,104 shares outstanding at December 31, 1981, as follows:

Dividend	Authorized and Outstanding Shares	Entitled Per Share Upon Voluntary Liquidation Redemption: Amount	Through	And Thereafter To Amounts Declining In Steps To
$7.325	700,000	$110.00	3/31/83	$101.00 after 3/31/88
8.40	800,000	115.00	3/31/84	100.00 after 3/31/04
9.125	192,000	107.00	9/19/86	102.00 after 9/19/91
8.20	600,000(1)	115.00	9/20/87	100.41 after 9/20/96
8.60	347,104(2,4)	107.00	12/20/87	100.00 after 12/20/97
8.625	370,000(3)	108.63	6/20/83	100.00 after 6/20/02
8.925	280,000(5)	108.93	9/20/84	100.00 after 9/20/09
Total	3,289,104(6)			
Less shares due within one year	19,834(6)			
Balance	3,269,270(7)			

(1) Issued September 1977. (2) Issued December 1977. (3) 355,000 shares issued in May 1978 and 15,000 shares issued in September 1978. (4) No voluntary redemption prior to December 20, 1982. (5) Issued November 1979. (6) Sinking Fund requirements call for annual redemption at $100 per share as follows:

Series	Annual Sinking Fund Requirements Shares	Beginning	Ending	Series	Annual Sinking Fund Requirements Shares	Beginning	Ending
$8.60	8,000	Dec. 1978	Dec. 2010	$8.625	18,500	June 1984	June 2002
9.125	11,834	Sept. 1981	Sept. 2000	8.925	10,500	Sept. 1984	Sept. 2009
8.20	30,000	Sept. 1983	Sept. 1996	8.40	32,000	April 1985	April 2009
7.325	28,000	April 1984	April 2008				

(7) Maturities through 1986 are as follows: 1982-$1,983,000; 1983-$4,983,000; 1984-$10,683,000; 1985-$13,883,000; and 1986-$13,883,000.

The total number of authorized shares for all Preferred Stock is 7,500,000 shares. Upon involuntary liquidation, all Preferred Stock shares are entitled to receive $100 per share plus accrued dividends. Dividends are cumulative and payable March 20, June 20, September 20 and December 20.

H. Preferred and Preference Stock Not Subject to Mandatory Redemption, Common Stock and Other Paid-In Capital:

Preferred Stock Not Subject to Mandatory Redemption:

Preferred Stock not subject to mandatory redemption was represented by 2,890,140 shares outstanding at December 31, 1981, as follows:

Dividend	Authorized and Outstanding Shares	Entitled Per Share Upon Voluntary Liquidation Redemption: Amount	Through	And Thereafter To Amounts Declining In Steps To
$5.00	106,677	$112.50		
4.04	12,926	102.27		
4.20	14,797	102.50		
4.12	32,534	103.73		
4.80	73,206	101.00		
7.72	350,000	103.50	5/31/84	$101.50 Thereafter
8.84	350,000	107.00	8/31/82	101.00 after 8/31/85
7.45	400,000	103.00	2/29/84	101.00 Thereafter
7.20	450,000	106.00	1/31/82	101.00 after 1/31/85
7.72(1972 Series)	500,000	106.00	9/30/82	101.00 after 9/30/85
9.75	600,000	106.50	2/28/86	101.00 after 2/28/91
Total	2,890,140			

Preference Stock Not Subject to Mandatory Redemption:

In 1975, the Company issued 2,400,000 shares of $2.90 Dividend Preference Stock at $23.90 per share which aggregated $57,360,000. The Preference Stock is redeemable at the Company's option and declines in steps to $25.25 on May 1, 1990. Upon liquidation, all shares are entitled to receive $25 per share plus accrued dividends. Dividends are cumulative and payable March 20, June 20, September 20 and December 20.

Common Stock:

Common Stock was represented by 104,768,299 shares outstanding at December 31, 1981. In addition, 2,259,435 shares (based on the conversion price of $22.125 per share) are reserved for conversion of the 3⅝% Convertible Debentures due May 1, 1986. During the years 1977 through 1981 the following changes in Common Stock occurred:

Year	Public Offering		Dividend Reinvestment and Customer Installment Plans		Employee Savings and Stock Ownership Plans		Total Outstanding	
	Shares	Additions to Capital Account	Shares	Additions to Capital Account	Shares	Additions to Capital Account	Shares	Capital Account
1981	2,000,000	$22,290,000	2,119,961	$25,097,483	694,181	$7,974,573	104,768,299	$1,457,072,496(1)
1980	5,000,000	53,950,000	1,505,423	18,852,552	574,622	6,261,638	99,954,157	1,400,874,668(1)
1979	6,000,000	64,050,000	1,049,874	12,925,755	583,138	7,222,482	92,874,112	1,319,303,162
1978	5,000,000	68,275,000	827,514	11,689,651	337,143	4,774,135	85,241,100	1,235,104,925
1977	5,000,000	70,400,000	626,886	9,229,553	284,167	4,212,884	79,076,443	1,150,366,139(2)
							73,165,390(3)	1,006,523,702

(1) Includes $835,772 and $2,507,316 of transfers from Other Paid-In Capital in 1981 and 1980,respectively.
(2) In May 1977, $60,000,000 was transferred from Earnings Reinvested in Business to the Common Stock account as authorized by the Board of Directors.
(3) Outstanding January 1, 1977.

On May 8, 1979, the number of authorized shares was increased from 95,000,000 to 120,000,000.

Other Paid-In Capital:

In 1977, the Company solicited tenders of shares of certain series of Preferred Stock in exchange for shares of $8.60 Dividend Preferred Stock. The difference between the stated value of the shares exchanged and that of the $8.60 Dividend series shares amounting to $27,859,000, net of cash paid for fractional shares, was transferred to Other Paid-In Capital.

In 1981 and 1980, the Company transferred $836,000 and $2,507,000, respectively, associated with $8.60 Dividend shares redeemed to the Common Stock account.

I. Short-Term Loans and Compensating Balances:

	Year End			Daily Average Outstanding		
	Maturity	Amount	Interest Rate At End of Year(1)	Amount	Interest Rate(1)	Maximum Outstanding
1981						
Commercial paper.....	(2)	$148,896,000	13.61%	$184,608,000	16.60%	$279,395,000
Master notes.....	(3)	9,542,000	12.75	2,965,000	14.26	18,237,000
Pollution control notes	(3)	6,500,000	9.55	5,781,000	8.81	9,660,000
1980						
Commercial paper.....	(2)	72,003,000	18.25	155,772,000	13.54	280,525,000
Master notes.....	(3)	2,058,000	15.00	3,520,000	10.47	12,300,000
Pollution control notes	(2)	9,660,000	7.26	5,177,000	7.09	9,660,000
1979						
Commercial paper.....	(2)	122,543,000	14.25	69,736,000	11.03	175,750,000
Master notes.....	(3)	6,937,000	12.25	3,520,000	9.98	6,937,000
Pollution control notes	(2)	2,250,000	7.25	203,000	7.25	2,250,000

(1) Weighted average interest. (2) Principally 30 to 90 days. (3) Maximum 180 days.

Available bank lines of credit amounted to $415,975,000 at December 31, 1981, including $200,000,000 applicable to revolving credit agreements effective through August 30, 1985. The Company maintains compensating balances of up to 10% or pays fees in lieu of balances in connection with its lines of credit. Utilization under the lines of credit may require additional balances or fees. Compensation for the revolving credit agreements are consistent with the requirements for the lines of credit.

J. Long-Term Debt:

Long-term debt outstanding at December 31, 1981:

First and refunding mortgage bonds(1):	
Series J 3¼%, due 1982	$ 20,000,000
Series DD 10½%, due 1983	75,000,000
Series K 3⅛%, due 1984	25,000,000
Series L 3¼%, due 1985	25,000,000
Series A 6⅞%, due 1985	8,000,000*
Series M 4⅛%, due 1986	20,000,000
Series N 4½%, due 1987	20,000,000
Series O 3⅞%, due 1988	25,000,000
1981 Series A 15¾%, due 1989	100,000,000**
Series P 4⅝%, due 1990	25,000,000
Series Q 4⅞%, due 1991	30,000,000
Series R 4⅜%, due 1993	30,000,000
Series S 4½%, due 1993	30,000,000
Series FF 11%, due 1994	108,750,000
Series EE 11%, due 1994	80,000,000
Series T 4½%, due 1995	60,000,000
1981 Series B 15¾%, due 1996	8,000,000**
1981 Series C 15¾%, due 1996	30,000,000**
Series U 5⅛%, due 1997	50,000,000
Series V 6⅞%, due 1997	50,000,000
Series KK 8.95%, due 1998	55,000,000
Series W 7⅛%, due 1999	85,000,000
Series X 7¾%, due 1999	75,000,000
Series Y 9%, due 2000	83,725,000
1980 Series A 12½%, due 2000	75,000,000
Series Z 8⅞%, due 2000	83,725,000
Series AA 7⅜%, due 2001	90,000,000
Series BB 7½%, due 2001	50,000,000
Series CC 7⅜%, due 2002	100,000,000
Series C 6.15%, due 2003	8,000,000*
1979 Series B 9.95%, due 2004	135,000,000
Series A 8½%, due 2005	18,000,000*
Series GG 10%, due 2005	100,000,000
Series HH 9¼%, due 2006	100,000,000
Series B 6¾%, due 2006	20,000,000*
Series II 8¾%, due 2006	100,000,000
Series JJ 8⅝%, due 2007	150,000,000
Series LL 9⅝%, due 2008	150,000,000
1979 Series A 10¼%, due 2009	100,000,000
Total	2,398,200,000
Term notes ($181,000,000 issued in 1981)(2)	521,000,000
Convertible debentures 3⅝%, due 1986	49,990,000
Pollution control revenue bonds(3)	44,750,000
Bath County project financing(4)	249,150,000
	3,263,090,000
Less amounts due within one year:	
Sinking fund obligations(1)	13,250,000
Term notes(2)	57,500,000
First and Refunding Mortgage Bonds	20,000,000
Pollution Control Revenue Bonds(3)	2,250,000
Less unamortized discount—net of premium	10,076,000
Total long-term debt	$3,160,014,000

* Pollution Control Series. ** Issued in 1981.

The Company redeemed $122,293,000 of long-term debt and sinking fund obligations due in 1981. Maturities (including cash sinking fund obligations) are as follows: 1982—$93,000,000; 1983—$148,000,000; 1984—$270,000,000; 1985—$422,900,000, and 1986—$105,115,000.

(1) The Mortgage provides for sinking funds as follows:

	Commencing	Annual Sinking Fund Requirements
Series J through CC	*	$10,000,000
Series EE and FF	Begun	13,250,000
Series KK	1984	2,750,000
1979 Series A and B	1985	10,750,000
1980 Series A, 1981 Series A, Pollution Control Series A	1986	6,125,000
1981 Series C	1987	4,875,000
Pollution Control Series B	1992	250,000
Pollution Control Series C	1989	375,000

* The Company may satisfy these requirements by waiving the privilege to issue an equal amount of Bonds by substituting property therefor and intends to do so in 1982.

Substantially all of the Company's property is subject to the lien of the Mortgage.

(2) Term Notes:

Principal Amount	Maturity	Variable Interest Rate: Percentage of Base Lending Rate of	Variable Interest Rate: Not to Exceed an Average of	Fixed Interest Rate
$ 50,000,000	1982	115%	8⅞%	
5,000,000	1982			8¼%
2,500,000	1982			11⅜
10,000,000	1983			8¼
2,500,000	1983			11⅜
5,000,000	1983			8⅝
500,000	1983	60	8½	
39,500,000	1983	60	9½	
6,000,000	1984			8.55
10,000,000	1984			8¼
5,000,000	1984	115	9.9	
5,000,000	1984	107½	9.9	
50,000,000	1984			10¼
25,000,000	1984			11⅞
25,000,000	1984	65	11	
25,000,000	1984			14.82
25,000,000	1984			14¾
25,000,000	1984			12¾
20,000,000	1985	115	8¾	
5,000,000	1985			8⅝
15,000,000	1985			15¼
5,000,000	1985			15½
15,000,000	1985			11⅞
25,000,000	1985			14⅘
50,000,000	1985			16.72
10,000,000	1987			14½
50,000,000	1988	*	9	
10,000,000	1995			12⅜
$ 521,000,000				

* 118% of the higher of commercial paper rate plus ½ of 1% or base lending rate. Interest not to be less than 8%.

(3) Pollution Control Revenue Bonds:

Principal Amount	Maturity	Interest Rate	Mandatory Sinking Fund Requirements: Annual Amount	Mandatory Sinking Fund Requirements: Commencing
$ 4,000,000	1982-83*	7.3-7.4%	None	
4,250,000	1989	8.0	$250,000	Begun
			500,000	1984
			750,000	1987
22,000,000	2002	5⅝	500,000	1990
14,500,000	2004	8¾	750,000	1990
$44,750,000				

* $2,000,000 of the $4,000,000 principal amount of Serial Bonds mature annually.

(4) In 1980, the Company issued a collateral note securing borrowings of a trust which is financing construction expenditures (including interest) after 1979 on the Bath County Pumped Storage Project. Borrowings under the present arrangements, which increased by $47,340,000 during 1981, are limited to $250 million and mature on December 31, 1985. Weighted average interest for 1981, including fees for supporting lines of credit, amounted to 17.6%.

K. Effect of Rate Increases on Operating Revenues:

In 1981, the Company obtained rate relief of about $222 million on an annual basis from the three State Commissions, FERC and non-jurisdictional customers.

Rate increases and decreases, exclusive of fuel cost recovery, which became effective for portions of the following years increased (decreased) operating revenues for the respective years by the approximate amounts shown:

	(Millions of Dollars)				
	1981	1980	1979	1978	1977
Electric	**$92.2***	$36.4	$56.4	$56.9	$3.0
Gas	**(.2)**	(.7)	.4		

* Includes approximately $15.5 million subject to refund.

L. Retirement Annuity Plan:

Costs to the Company under the plan were: 1981—$11,187,000; 1980—$11,186,000; 1979—$9,697,000; 1978—$8,586,000; and 1977—$7,594,000. At January 1, 1981, the date of the latest available actuarial report the unfunded liability of the plan amounted to approximately $12.7 million.

The present value of benefits, as of January 1, 1981, as determined by the actuaries, was as follows:

Vested accumulated plan benefits	$125,756,000
Nonvested accumulated plan benefits	16,373,000
Total	$142,129,000
Plan net assets available for benefits	$159,027,000

A 7% rate of return is used in determining the present value of vested and nonvested accumulated plan benefits.

M. Commitments and Contingencies:

The Company has made substantial commitments in connection with its construction program, which is presently estimated to be $799 million for 1982. Additional financing is contemplated in connection with this program.

The major portion of Laurel Run Mining Company's mining equipment is leased. As guarantor, the Company has a contingent liability for annual lease payments of $1.0 million in 1982 and $.8 million in 1983.

The FERC has directed the Company to write-off $6.3 million ($4.3 million of AFC and $2.0 million of other costs) associated with a boiler implosion in 1974 at Yorktown Unit 3 which the Company has capitalized on its books. The Company has filed an appeal of FERC's decision in the Federal Circuit Court of Appeals.

In 1979, settlement was reached in the Westinghouse uranium dispute which provides for cash and discounts on uranium and goods and services over the period 1979-1997 which are estimated to equal the value of contracts litigated had they been fully performed by Westinghouse. Through December 31, 1981, the Company had received $176 million in cash and goods and services, $29 million of which was received in 1981. Settlement proceeds are applied to reduce fuel expenses to the extent that fuel expenses reflect higher costs as a result of the breached contracts. In 1979 the Company filed with the Internal Revenue Service a request for a ruling that the value received from the settlement be treated as a reduction in fuel expense over the life of the nuclear fuel, and not as taxable income in the year of the settlement. The ruling, received on June 1, 1981, held that cash and the value of discounts on purchases of equipment and services accrued at the time of settlement and could be used to offset the damages in the cost of replacement uranium acquired up to the date of settlement. This treatment was not extended to replacement uranium acquired after the date of settlement. The Company, together with other utilities involved in the Westinghouse settlement, is pursuing a legislative remedy to this problem. If the Company is required to pay taxes as a result of the settlement, such provision would be normalized in order to match the tax effect of the settlement with the credit to fuel expenses per books.

A group of utilities, including the Company, has established Nuclear Electric Insurance Limited (NEIL), a mutual insurance company that provides insurance for replacement power costs resulting from an accident at a nuclear site. The Company has purchased the maximum coverage available, which is $2.3 million per week per unit for the first 52 weeks of coverage and $1.15 million per week per unit for the next 52 weeks, subject to an initial 26-week deductible period. In addition, NEIL began providing excess property damage insurance through a separate program that commenced on November 15, 1981 and which is ultimately to provide $500 million of property insurance coverage to meet losses in excess of $500 million. The company has committed to purchase the maximum amount available, subject to regulatory approvals. The annual premiums for the current year are $6.7 million for the replacement power insurance. The premiums for the excess property coverage will be $1.9 million for the initial year. Each program also obligates participants to a retrospective premium adjustment for six years following each policy year. These adjustments are not to exceed five times the annual premium, in the case of the replacement power insurance, and 7.5 times the annual premium, in the case of the excess property coverage, in the event that losses exceed the accumulated funds of the applicable program.

For a discussion of possible sales of power station projects and related facilities see *Capital Resources* under MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

N. Quarterly Financial Data (Unaudited):

The following amounts (not examined by independent certified public accountants) reflect all adjustments, consisting of only normal recurring accruals, necessary in the opinion of the Company for a fair statement of the results for the interim periods, except as disclosed below for the adjustments recorded in the third and fourth quarter of 1981 and the fourth quarter of 1980.

Quarter	Operating Revenues	Operating Income	Balance for Common Stock	Earnings Per Share of Common Stock	Quarter	Operating Revenues	Operating Income	Balance for Common Stock	Earnings Per Share of Common Stock
1981	(Thousands of Dollars)				1980	(Thousands of Dollars)			
1st	$554,203	$106,544	$40,260	$.40	1st	$572,820	$88,649	$40,173	$.43
2nd	484,984	97,194	23,491	.23	2nd	473,472	79,395	28,395	.30
3rd	567,628	141,427	63,992	.63(2,3)	3rd	576,472	107,780	57,311	.60
4th	555,038	123,467	52,871	.51(1)	4th	497,010	113,708	58,450	.60(4)

Results for interim periods may fluctuate as a result of weather conditions, rate relief and other factors.

(1) In December 1981, eleven of the Company's North Carolina municipal customers terminated contracts for electric service by the Company to purchase their own generating capacity from another utility. Accordingly, the Company agreed to phase out its wholesale power contracts with these customers over a two-year period beginning December 30, 1981, in return for a payment to the Company on that date of approximately $15.5 million. Of this amount, $13.3 million was credited to other income with a resulting increase in balance for common stock and earnings per share of $7.2 million and $.07, respectively, and $2.2 million was credited to accumulated amortization of nuclear fuel.

(2) From September 1978 through August 1981 the Company provided a reserve for the difference between interim rates in effect for FERC jurisdictional customers and estimated final rates. The Company neither sought nor received regulatory approval to provide deferred taxes on this reserve which was not considered to be deductible for Federal income tax purposes until a refund was made. As a result of a final rate order received in the third quarter of 1981, a refund substantially equal to the amount previously provided was made. The tax benefit of this refund had the effect of reducing the Company's 1981 provision for Federal income taxes by $12,419,000 and of increasing 1981 earnings per share by $0.12.

(3) Beginning in the third quarter of 1981 the investment tax credit applicable to nuclear fuel is being amortized over the average burn life of the fuel, which is three years, rather than over the average composite life of all plant assets. This refinement of the Company's method of amortizing the tax credits had the effect of reducing the 1981 provision for Federal income taxes by $5,292,000 (including $3,305,000 applicable to periods prior to 1981) and of increasing 1981 earnings per share by $.05. The effect of this refinement on the results of operations of periods prior to 1981 would not have been significant.

(4) In the fourth quarter of 1980, the Company began accounting on an inventory basis for spare parts and equipment which had been expensed. The effect of the adjustment, which amounted to $8.9 million ($4.8 million net of Federal income taxes), was to increase earnings per share by $.05.

O. Supplementary Data On Changing Prices (Unaudited):

The following supplementary information is supplied in accordance with the requirements of FASB Statement No. 33, Financial Reporting and Changing Prices, for the purpose of providing certain information about the effects of changing prices. It should be viewed as an estimate of the approximate effect of inflation, rather than as a precise measure.

Constant dollar amounts represent historical costs stated in terms of dollars of equal purchasing power, as measured by the Consumer Price Index for All Urban Consumers (CPI-U). Current cost amounts reflect the changes in specific prices of plant from the date the plant was acquired to the present, and differ from constant dollar amounts to the extent that specific prices have increased more or less rapidly than prices in general.

The current cost of property, plant and equipment, which includes intangible plant, property held for future use and construction work in progress, represents the estimated cost of replacing existing plant assets and was determined by indexing the surviving plant by the Handy-Whitman Index of Public Utility Construction Costs. The current cost of land and general plant was determined by using the CPI-U. The current year's provision for depreciation on the constant dollar and current cost amounts of property, plant and equipment was determined by applying the Company's depreciation rates to the indexed plant amounts.

Fuel used in electric generation has been restated to reflect the constant dollars and current cost of nuclear fuel. The cost of other types of fuel used in electric generation and gas purchased for resale have not been restated since these costs are considered to be current.

Fuel inventories, with the exception of nuclear fuel, have not been restated from their historical cost in nominal dollars. The nuclear fuel inventory is considered an integral part of the plant investment and, therefore, should be restated and adjusted to net recoverable cost. As indicated above, other types of fuel inventories have not been restated since the costs of these assets are considered to be current.

Preferred stock subject to mandatory redemption has been classified as a monetary liability in determining the gain from decline in purchasing power of dollars related to net amounts owed, in accordance with the definition of a monetary liability in FASB Statement No. 33.

As prescribed in Statement 33, income taxes were not adjusted.

To properly reflect the economics of rate regulation in the Statement of Income from Continuing Operations, the adjustment of property, plant and equipment to net recoverable cost should be offset or combined, as appropriate, by the gain from the decline in purchasing power of the dollars related to net amounts owed. During a period of inflation, holders of monetary assets suffer a loss of general purchasing power while holders of monetary liabilities experience a gain. The gain from the decline in purchasing power of the dollars related to net amounts owed is primarily attributable to the substantial amount of debt which has been used to finance property, plant and equipment. Since the depreciation on this plant is limited by regulation to the recovery of historical costs, a holding gain on debt is not allowed and the Company is limited to recovery of the embedded cost of the asset.

Statement of Income from Continuing Operations Adjusted for Changing Prices (Unaudited)

	For The Year Ended December 31, 1981		
	Conventional Historical Cost	Constant Dollar Average 1981 Dollars	Current Cost Average 1981 Dollars
		(Thousands of Dollars)	
Operating revenues	$2,161,853	$2,161,853	$2,161,853
Fuel used in electric generation	555,466	587,028	611,589
Depreciation	174,120	367,351	395,036
Other operating and maintenance expense	869,966	869,966	869,966
Federal income taxes	93,669	93,669	93,669
Interest expense (net of allowance for borrowed funds used during construction)	283,745	283,745	283,745
Other income and deductions-net	(52,893)	(52,893)	(52,893)
	1,924,073	2,148,866	2,201,112
Income (loss) from continuing operations (excluding adjustment to net recoverable cost)	$ 237,780	$ 12,987*	$ (39,259)
Increase in specific prices (current cost) of property, plant and equipment held during the year**			$1,561,522
Adjustment to net recoverable cost		$ (272,258)	(901,598)
Effect of increase in general price level			(879,936)
Excess of increase in general price level over increase in specific prices after adjustment to net recoverable cost			(220,012)
Gain from decline in purchasing power of dollars related to net amounts owed		307,911	307,911
Net		$ 35,653	$ 87,899

* Including the adjustment of property, plant and equipment to net recoverable cost, the loss from continuing operations on a constant dollar basis would have been $259,271,000 for 1981.

** At December 31, 1981, current cost of property, plant and equipment, net of accumulated depreciation and amortization, was $11,243,476,000, while historical cost or net cost recoverable through depreciation and amortization was $6,012,888,000.

Five Year Comparison of Selected Supplementary Financial Data Adjusted for Effects of Changing Prices (Unaudited)

	Years Ended December 31,				
	1981	1980	1979	1978	1977
	(In Thousands* of Average 1981 Dollars)				
Operating revenues	$2,161,853	$2,339,653	$2,134,229	$2,042,170	$2,039,413
Historical cost information adjusted for general inflation					
Income from continuing operations (excluding adjustment to net recoverable cost)	$12,987	$97,295	$101,489		
Income (loss) per common share (after dividend requirements on preferred and preference stock)	$(0.43)	$0.35	$0.38		
Net assets at year-end at net recoverable cost	$2,423,401	$2,331,269	$2,463,378		
Current cost information					
Income (loss) from continuing operations (excluding adjustment to net recoverable cost)	$(39,259)	$54,488	$47,256		
(Loss) per common share (after dividend requirements on preferred and preference stock)	$(0.95)	$(0.09)	$(0.25)		
Excess of increase in general price level over increase in specific prices after adjustment to net recoverable cost	$220,012	$479,689	$574,166		
Net assets at year-end at net recoverable cost	$2,423,401	$2,331,269	$2,463,378		
General information					
Gain from decline in purchasing power of dollars related to net amounts owed	$307,911	$429,314	$465,314		
Cash dividends declared per common share	$1.42	$1.55	$1.73	$1.81	$1.87
Market price per common share at year-end	$11.37	$10.95	$12.44	$18.80	$21.22
Average consumer price index (1967 = 100)	272.4	246.8	217.4	195.4	181.5

* Except per share amounts and indexes.

Ten Year Comparative Summary of Performance

(Thousands of Dollars)

	1981	1980	1979	1978
Operating revenues:				
Electric	**$2,069,764**	$2,049,518	$1,647,928	$1,413,866
Gas	**92,089**	70,256	55,381	51,039
Total operating revenues	**2,161,853**	2,119,774	1,703,309	1,464,905
Expenses (operation and maintenance)	**1,292,318**	1,390,817	1,069,241	869,232
Depreciation	**174,120**	145,032	136,280	117,481
Amortization of abandoned project costs	**12,203**	6,933	7,292	6,760
Taxes:				
Federal income:				
Currently payable (refundable)	**14,732**	11,200	8,449	23,163
Investment tax credits, including carry-back	**15,554**	11,798	570	40,294
Investment tax credits, amortization	**(8,843)**	(5,171)	(5,820)	(5,467)
Deferred—accelerated amortization	**(1,547)**	(1,547)	(1,547)	(1,547)
—liberalized depreciation	**53,847**	41,108	32,418	38,509
—other	**19,926**	12,616	35,674	(22,294)
Other	**120,911**	117,456	104,358	93,499
Total operating expenses	**1,693,221**	1,730,242	1,386,915	1,159,630
Operating income	**468,632**	389,532	316,394	305,275
Other income:				
Allowance for other funds used during construction	**44,264**	73,206	66,603	64,002
Allowance for funds used during construction				
Miscellaneous, net	**8,629**	2,423	974	1,342
Total other income	**52,893**	75,629	67,577	65,344
Income before interest charges	**521,525**	465,161	383,971	370,619
Interest charges:				
Interest on long-term debt	**280,012**	234,561	204,392	184,947
Other	**44,276**	28,530	12,417	6,677
Allowance for borrowed funds used during construction	**(40,543)**	(39,550)	(29,305)	(24,869)
Total interest charges	**283,745**	223,541	187,504	166,755
Income before cumulative effect of change in accounting method	**237,780**	241,620	196,467	203,864
Cumulative effect to January 1, 1974 of accruing estimated unbilled revenues, net of taxes				
Net income	**237,780**	241,620	196,467	203,864
Dividends paid:				
On preferred and preference stock	**57,170**	57,290	55,046	53,588
On common stock	**144,937**	133,005	120,638	103,474
Total dividends	**202,107**	190,295	175,684	157,062
Earnings reinvested in business	**$ 35,673**	$ 51,325	$ 20,783	$ 46,802
Shares of common stock—average for year (thousands)	**101,856**	95,520	86,965	80,060
Earnings per share of common stock	**$1.77**	$1.93	$1.63	$1.88
Dividends paid per share of common stock	**$1.42½**	$1.40	$1.38	$1.30
Pay-out ratio	**80%**	72%	85%	69
Return of capital:				
Common stock dividends	**40.22%**	100.000%	(2)	
Preferred stock dividends		3.300%		
Preference stock dividends		100.000%		
Utility plant at original cost	**$7,487,634**	$6,836,094	$6,307,644	$5,626,671
Utility plant expenditures	**$ 676,295**	$ 681,120	$ 708,756	$ 529,186
Accumulated depreciation and amortization	**$1,474,746**	$1,249,629	$1,079,142	$ 940,958
Capitalization:				
Preferred and preference stock	**$ 675,284**	$ 677,268	$ 678,451	$ 651,634
Common equity	**1,952,476**	1,861,656	1,731,762	1,627,179
Debt (excluding short-term debt)	**3,263,090**	3,019,053	2,681,360	2,460,060
Total capitalization	**$5,890,850**	$5,557,977	$5,091,573	$4,738,873
Short-term debt—pending permanent financing	**$ 164,938**	$ 83,721	$ 131,730	$ 3,437
Capitalization ratios:				
Preferred and preference stock	**12%**	12%	13%	14
Common equity	**33**	34	34	34
Debt (excluding short-term debt)	**55**	54	53	52

(1) Includes non-recurring cumulative effect of change in accounting for unbilled revenues of $.24 per share.
(2) 1979 Return of capital was 33.02% for the first quarter and 91.95% for the remainder of the year.

1977	1976	1975	1974	1973	1972	1971
1,313,937	$1,060,663	$ 998,933	$ 735,962	$ 524,963	$ 445,668	$ 390,370
44,923	43,413	34,403	28,050	26,000	25,185	23,302
1,358,860	1,104,076	1,033,336	764,012	550,963	470,853	413,672
850,823	647,965	629,162	478,716	278,750	264,906	218,846
98,527	95,191	89,805	77,757	68,436	53,058	49,950
3,173						
9,191	2,209	(1,142)	(7,678)	(1,010)	(6,850)	8,652
23,548	35,568	2,286	(3,195)	3,901	7,368	1,952
(4,539)	(3,028)	(2,452)	(2,412)	(2,413)	(2,225)	(2,062)
(1,547)	(1,547)	(1,547)	(1,547)	(1,547)	(1,547)	(1,547)
13,101	12,320	9,360	3,202			
19,982	3,229	20,873	5,018	7,265	1,356	1,050
81,174	71,413	57,169	48,216	42,170	36,629	33,514
1,093,433	863,320	803,514	598,077	395,552	352,695	310,355
265,427	240,756	229,822	165,935	155,411	118,158	103,317
72,361						
	80,429	66,873	65,735	57,359	58,451	39,993
(663)	491	544	411	336	(156)	142
71,698	80,920	67,417	66,146	57,695	58,295	40,135
337,125	321,676	297,239	232,081	213,106	176,453	143,452
168,885	147,481	122,951	94,058	78,350	67,554	58,130
5,748	7,409	19,556	23,214	10,684	5,162	3,274
(27,301)						
147,332	154,890	142,507	117,272	89,034	72,716	61,404
189,793	166,786	154,732	114,809	124,072	103,737	82,048
			12,353			
189,793	166,786	154,732	127,162	124,072	103,737	82,048
47,719	43,821	35,971	30,419	24,147	16,472	12,216
91,225	82,923	70,786	60,165	54,796	46,905	41,993
138,944	126,744	106,757	90,584	78,943	63,377	54,209
$ 50,849	$ 40,042	$ 47,975	$ 36,578	$ 45,129	$ 40,360	$ 27,839
74,025	68,137	60,854	52,100	47,021	41,883	37,829
$1.92	$1.80	$1.95	$1.86(1)	$2.13	$2.08	$1.85
$1.24	$1.22½	$1.18	$1.18	$1.16½	$1.12	$1.12
64%	67%	60%	71%	55%	54%	60%
72.654%	25.267%		100.000%	49.407%	100.000%	96.724%
			100.000%		55.565%	
5,109,099	$4,609,416	$4,142,900	$3,739,395	$3,298,447	$2,847,614	$2,416,130
569,068	$ 481,601	$ 432,139	$ 460,912	$ 486,709	$ 472,819	$ 380,268
803,604	$ 700,254	$ 609,304	$ 545,296	$ 476,121	$ 414,941	$ 373,834
619,109	$ 583,807	$ 503,807	$ 446,447	$ 366,447	$ 296,447	$ 201,447
1,493,521	1,334,639	1,211,282	1,042,677	948,369	810,121	680,800
2,238,400	2,038,150	1,803,150	1,578,350	1,289,890	1,242,440	1,070,440
4,351,030	$3,956,596	$3,518,239	$3,067,474	$2,604,706	$2,349,008	$1,952,687
53,050	$ 26,500	$ 110,050	$ 256,945	$ 220,150	$ 88,400	$ 61,800
14%	15%	14%	15%	14%	13%	10%
34	34	35	34	36	34	35
52	51	51	51	50	53	55

Ten Year Operating Statistics

ELECTRIC DEPARTMENT	1981	1980	1979	1978
Operating revenues (thousands):				
Residential	**$ 814,152**	$ 806,156	$ 637,519	$ 563,56
Commercial	**541,264**	534,241	431,191	392,10
Industrial	**261,825**	281,316	220,814	182,90
Other sales of electric energy	**436,663**	413,022	347,276	268,21
Other electric revenues	**15,860**	14,783	11,128	7,09
Total operating revenues—electric	**$2,069,764**	$2,049,518	$1,647,928	$1,413,86
Population served at retail—estimated	**3,638,000**	3,579,000	3,523,000	3,465,00
Number of customers:				
Residential	**1,238,530**	1,208,500	1,174,351	1,138,47
Commercial	**123,939**	120,869	117,965	115,12
Industrial	**920**	920	920	92
Other	**17,749**	16,878	15,873	15,44
Total customers	**1,381,138**	1,347,167	1,309,109	1,269,95
Sales of electricity—Mwh (thousands):				
Residential	**13,399**	13,154	12,397	12,40
Commercial	**9,816**	9,597	9,161	9,17
Industrial	**6,416**	6,459	6,460	6,15
Other	**10,275**	10,035	9,557	9,34
Total sales of electricity	**39,906**	39,245	37,575	37,06
Losses and miscellaneous system uses	**2,983**	3,244	2,909	2,90
Total distribution—energy supply	**42,889**	42,489	40,484	39,96
Source of electricity—Mwh (thousands):				
Steam—Fossil	**16,539**	18,840	24,301	24,43
—Nuclear	**17,818**	11,466	7,055	14,09
Hydro	**263**	616	1,122	96
Other	**201**	208	356	39
Net purchased and interchanged	**8,068**	11,359	7,650	6
System output	**42,889**	42,489	40,484	39,96
Interchange deliveries for account of others	**325**	326	325	32
Company's service area output	**43,214**	42,815	40,809	40,29
Company's service area peak load—Mw	**8,638**	8,484	7,929	7,80
Power supply available for peak load—Mw				
Generating capability:				
Steam—Fossil	**6,112**	6,144	6,321	6,32
—Nuclear	**3,199**	2,329	2,448	2,44
Hydro	**326**	326	326	32
Other	**439**	439	439	43
Total generating capability	**10,076**	9,238	9,534	9,53
SEPA power disposed of in Company's service area	**165**	165	165	16
Available for firm peak load	**10,241**	9,403	9,699	9,69
Purchase (sale) outside service area	**900**	1,300	300	30
Available for service area peak load	**11,141**	10,703	9,999	9,99
BTU per kilowatt-hour generated	**11,170**	11,235	11,067	11,01
Average fuel cost per KWH generated-mills	**17.77**	21.76	20.44	14.0
Electric line—pole miles	**42,502**	42,297	42,149	41,69
Underground construction—miles of route	**10,775**	10,127	9,314	8,39

* Excludes the cumulative effect to January 1, 1974 of accruing estimated unbilled revenues shown as a nonrecurring item on the income statement, r of taxes.

1977	1976	1975	1974	1973	1972	1971
524,336	$ 420,150	$ 402,889	$ 308,834	$ 229,860	$ 191,924	$ 169,113
365,340	298,681	288,357	211,486	150,758	130,599	113,646
176,573	144,770	137,181	106,309	66,131	58,785	48,375
242,686	193,096	166,854	106,018	75,170	61,440	56,392
5,002	3,966	3,652	3,315	3,044	2,920	2,844
,313,937	$1,060,663	$ 998,933	$ 735,962*	$ 524,963	$ 445,668	$ 390,370
,415,000	3,365,000	3,315,000	3,270,000	3,225,000	3,185,000	3,150,000
,100,876	1,071,528	1,041,234	1,018,346	989,471	954,374	920,839
111,662	108,197	105,942	105,531	103,253	100,175	98,223
920	920	918	916	910	894	874
14,922	14,462	14,881	13,045	12,350	11,817	11,392
,228,380	1,195,107	1,162,975	1,137,838	1,105,984	1,067,260	1,031,328
11,867	11,137	10,373	9,850	9,911	8,775	8,121
8,762	8,455	7,970	7,307	7,330	6,471	5,980
6,022	6,011	5,404	5,658	5,535	5,136	4,683
8,806	8,510	7,741	7,120	7,268	6,529	5,902
35,457	34,113	31,488	29,935	30,044	26,911	24,686
2,792	2,261	2,585	2,518	2,335	2,199	2,019
38,249	36,374	34,073	32,453	32,379	29,110	26,705
26,403	27,090	23,562	22,819	22,311	23,710	24,335
9,481	7,740	8,969	5,953	6,857	370	
444	599	988	774	949	1,071	825
625	407	226	629	459	558	323
1,296	538	328	2,278	1,803	3,401	1,222
38,249	36,374	34,073	32,453	32,379	29,110	26,705
325	326	325	325	315	312	307
38,574	36,700	34,398	32,778	32,694	29,422	27,012
7,902	7,040	7,133	6,734	6,900	6,232	5,295
6,321	6,321	6,321	5,684	4,866	4,306	4,334
1,550	1,576	1,576	1,576	1,576	788	
326	326	326	326	326	326	326
439	454	469	530	530	530	530
8,636	8,677	8,692	8,116	7,298	5,950	5,190
165	165	165	165	165	132	132
8,801	8,842	8,857	8,281	7,463	6,082	5,322
300	313	316	251	122	680	610
9,101	9,155	9,173	8,532	7,585	6,762	5,932
10,933	10,739	10,892	10,868	10,673	10,529	10,382
15.23	12.94	13.06	12.43	4.98	4.63	4.28
41,446	41,186	40,663	40,121	39,578	39,055	38,404
7,794	6,824	6,266	5,641	4,772	4,055	3,367

Directors

	Membership of Committees of the Board ○ Committee Chairman ● Member ■ Ex Officio				
	Finance	Audit	Nominating	Organization and Compensation	Employee Benefit
John B. Bernhardt, President Virginia National Bankshares Inc., Norfolk	●		●		
William W. Berry, President	■				■
James F. Betts, President Continental Financial Services Company, Richmond				●	●
Milton L. Drewer, Jr., President First American Bank of Virginia, McLean	●	●			
Mrs. Mary C. Fray, Culpeper					●
Bruce C. Gottwald, President Ethyl Corporation, Richmond	●				
Dr. Allix B. James, President Emeritus Virginia Union University, Richmond					○
T. Justin Moore, Jr., Chairman of the Board of Directors	○			■	
William S. Peebles, III, President W. S. Peebles and Company, Inc., Lawrenceville		○	●		
Shirley S. Pierce, President The Ahoskie Fertilizer Company, Inc., Ahoskie, N.C.					●
Kenneth A. Randall, President, The Conference Board, New York	●			●	
William T. Roos, President, Penn Luggage, Inc., Hampton		●			●
Roy R. Smith, Chairman of the Board Smith's Transfer Corporation, Staunton				○	
William F. Vosbeck, Jr., President VVKR Incorporated, Alexandria			○	●	

Officers

T. Justin Moore, Jr., Chairman of the Board
and Chief Executive Officer, Age 56
William W. Berry, President and Chief Operating Officer, Age 49
Jack H. Ferguson, Executive Vice President, Age 50

Senior Vice Presidents

Samuel C. Brown, Jr., Power Station Engineering
and Construction, Age 56
John I. Oatts, Power Operations, Age 52
William L. Proffitt, Commercial Operations, Age 52

Vice Presidents

Wadsworth Bugg, Jr., Age 60
Paul G. Edwards, Age 43
Gerald C. Headley, Jr., Age 47
Robert F. Hill, Age 45
Charles M. Jarvis, Age 53
B. D. Johnson, Vice President and Controller, Age 49
Ronald H. Leasburg, Age 48
O. James Peterson, III, Vice President and Treasurer, Age 46
James T. Rhodes, Age 40
William C. Spencer, Age 49
William N. Thomas, Age 58

Corporate Secretary

S. Brooks Robertson, Age 64

Division Vice Presidents

Northern Division, James P. Cox, Jr., Age 63
Eastern Division, William H. Blackwell, Jr., Age 52
Southern Division, Randolph D. McIver, Age 51
Western Division, Richard W. Carroll, Age 63
Central Division, David W. Poole, Age 57
Virginia Natural Gas, Eugene C. Keeling, Age 58

Stock and Convertible Debenture Listings

New York Stock Exchange
Symbol—**VEL**

Transfer Agents—Registrars

United Virginia Bank, Richmond
The Chase Manhattan Bank, N.A., New York

Annual Meeting

April 21, 1982

Cassette Recordings of this 1981 Annual Report are available as a service to the visually impaired. Requests should be directed to the Corporate Secretary of the Company.

William W. Berry T. Justin Moore, Jr. John B. Bernhardt

William T. Roos Mrs. Mary C. Fray

James F. Betts Dr. Allix B. James

William F. Vosbeck, Jr. Roy R. Smith

William S. Peebles, III

Bruce C. Gottwald

Milton L. Drewer, Jr. Kenneth A. Randall

Shirley S. Pierce

Vepco
Virginia Electric and Power Company
P.O. Box 26666 • Richmond, Virginia 23261