Charles H. Cruse
Vice President
Nuclear Energy

1650 Calvert Cliffs Parkway
Lusby, Maryland 20657
410 495-4455

Constellation
Nuclear

Calvert Cliffs
Nuclear Power Plant

A Member of the
Constellation Energy Group

August 15, 2001

U. S. Nuclear Regulatory Commission
Washington, DC 20555

ATTENTION: Director, Nuclear Reactor Regulation

SUBJECT: Calvert Cliffs Nuclear Power Plant
Unit Nos. 1 & 2; Docket Nos. 50-317 & 50-318
Guarantee of Retrospective Premium

In accordance with the requirements of 10 CFR 140.21, we are attaching the guarantee of payment of deferred premiums for our Calvert Cliffs Nuclear Power Plant reactors.

Exhibit I	A copy of the 2000 Annual Report to Shareholders of Constellation Energy Group containing certified financial statements
Exhibit II	A copy of quarterly financial statements as of June 30, 2001
Exhibit III	A copy of Projected Cash Flow for the twelve months ended July 31, 2002
Exhibit IV	Narrative statement on curtailment/deferment of capital expenditures (if any) to ensure that retrospective premiums up to $10 million per reactor year for each nuclear incident would be available for payment.

Should you have questions regarding this matter, we will be pleased to discuss them with you.

Very truly yours,

for
C. H. Cruse
Vice President - Nuclear Energy

CHC/MJY/bjd

Attachments: As stated

cc: Document Control Desk, NRC

(Without Attachments)
R. S. Fleishman, Esquire
J. E. Silberg, Esquire
Director, Project Directorate I-1, NRC
D. M. Skay, NRC

H. J. Miller, NRC
Resident Inspector, NRC
R. I. McLean, DNR

M004

EXHIBIT I

2000 ANNUAL REPORT TO SHAREHOLDERS

Calvert Cliffs Nuclear Power Plant, Inc.
August 15, 2001

CONSTELLATION ENERGY GROUP

ANNUAL REPORT

2000

2 the power of two

C01

1

Be a leader in the wholesale merchant energy business in North America.

C02

2

Provide premier utility and energy-related services in Maryland and its surrounding region.

1 Constellation Energy Group + 1 BGE Corp.

focused on what they do best.

Constellation Energy Group

C03

2

for several years,

two strategies …

and now,

two companies.

Poindexter's Perspective
Chris Poindexter talks about accomplishments, strategy, and the future as 2 powerful companies. *(page 5)*

The Power 2 Compete
Constellation Energy is building itself into one of the country's top merchant energy businesses. *(page 10)*

The Power 2 Deliver
BGE Corp. will deliver energy and more to local retail customers and value to shareholders. *(page 16)*

Constellation Energy Group

2000 Annual Report to Shareholders

250 West Pratt Street
Baltimore, Maryland 21201
www.constellationenergy.com

Constellation Energy Group (NYSE: CEG) is a holding company that includes a group of competitive energy businesses focused mostly on power marketing and merchant generation in North America and the Baltimore Gas and Electric Company (BGE), a regulated energy delivery company in Central Maryland. In 2000, combined revenues totaled $3.9 billion.

Constellation Energy announced on October 23, 2000, that it intends to separate its wholesale merchant energy and retail energy businesses into two stand-alone publicly traded companies. It expects to receive all required approvals for separation by mid- to late-2001.

Merchant Energy

Constellation Power Source Holdings
Our integrated domestic merchant energy company provides wholesale customers in North America with solutions to their energy needs.

2000 Highlights:

- Ranked in the top 10 of U.S. power marketers for the year by *Power Markets Weekly*.
- Delivered nearly 160 million megawatt-hours in the national wholesale market.
- Assumed control of more than 6,200 megawatts of generation formerly owned by BGE, bringing its total power capacity controlled to more than 9,000 megawatts.
- Began construction on nearly 2,500 megawatts of new gas-fired merchant plants planned to come online in 2001 and 2002 in strategic areas across the country.

Constellation Nuclear
Our nuclear generation and consulting business brings together our pioneering experience and expertise in the nuclear power industry.

2000 Highlights:

- Announced on December 12 it would purchase Nine Mile Point nuclear power plants in Scriba, N.Y., which will add 1,550 megawatts to our merchant energy supply portfolio.
- Calvert Cliffs Nuclear Power Plant subsidiary:
  - Became first commercial generating plant in the U.S. to be granted 20-year extensions of its operating licenses.
  - Had its best performance in its 26-year history, setting a generation record of 13.8 million megawatt-hours in 2000, eclipsing the previous record of 13.3 million megawatt-hours set in 1998.
  - Finished among the leading nuclear plants for the fifth consecutive year for worker safety as measured by the Occupational Safety and Health Administration.

Utility and Retail Energy Services

Baltimore Gas and Electric Company
Our regulated gas and electric delivery utility serves more than 1.1 million electric and nearly 600,000 gas customers in Central Maryland.

2000 Highlights:

- Implemented retail customer choice of electric supply and transferred its generating assets to Constellation Energy's merchant energy businesses on July 1.
- Set a record low for the number of sustained electric service interruptions customers experienced.
- Set a gas delivery record on January 17, delivering 795,700 dekatherms, breaking its previous record set January 18, 1997, by 4 percent.
- Added nearly 14,000 new electric and 11,000 new gas customers to its delivery system.

BGE HOME
Our home products, commercial buildings, and electric and gas retail marketing business offers a wide range of energy products and services and commercial building systems primarily in Maryland.

2000 Highlights:

- Granted licenses to supply electricity in Maryland and gas in Pennsylvania.

Constellation Energy Source
Our energy products and services business provides customized energy solutions exclusively to commercial and industrial customers, primarily in the Mid-Atlantic region.

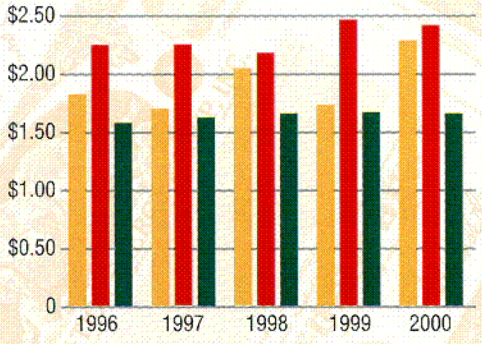
2000 Highlights:

- Closed national energy management consulting contracts with McCormick & Company, Rouse Company, and Mills Corporation; secured energy management contracts for Pittsburgh Steelers' new football stadium, Maryland's Department of Juvenile Services, and St. Mary's College.

C06

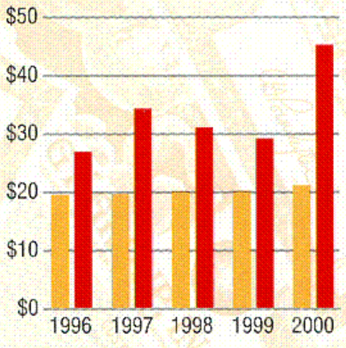
	2000	1999	% Change
	(In millions, except per share amounts)		
Common Stock Data			
Earnings per share			
Earnings per share before nonrecurring items	**$ 2.43**	$ 2.48	(2.0)%
Earnings per share before extraordinary item	**2.30**	2.18	5.5%
Earnings per share after extraordinary item	**2.30**	1.74	32.2%
Dividends declared per share	**$ 1.68**	$ 1.68	–
Average shares outstanding	**150.0**	149.6	0.3%
Return on reported average common equity			
Excluding nonrecurring charges to earnings	**11.9%**	12.3%	(3.3)%
Reported	**11.3%**	8.6%	31.4%
Book value per share—year end	**$ 20.95**	$ 20.01	4.7%
Market price per share—year end	**$ 45.06**	$ 29.00	55.4%
Market value of common stock—year end	**$ 6,783**	$ 4,337	56.4%
Financial Data			
Total revenues	**$ 3,879**	$ 3,786	2.5%
Income from operations	**$ 840**	$ 760	10.5%
Income before extraordinary item	**$ 345**	$ 326	5.8%
Extraordinary item, net of income taxes	**–**	(66)	–
Net income	**$ 345**	$ 260	32.7%
Assets			
Domestic merchant energy business	**$ 6,753**	$ 1,206	460.0%
Regulated utility business	**4,482**	7,228	(38.0)%
Other businesses and corporate items	**1,150**	1,250	(8.0)%
Total assets	**$ 12,385**	$ 9,684	27.9%
Total common equity	**$ 3,153**	$ 2,993	5.3%
Nonregulated capital expenditures	**$ 830**	$ 278	198.6%
Regulated capital expenditures	**$ 350**	$ 436	(19.7)%

Earnings and Dividends Declared Per Share of Common Stock



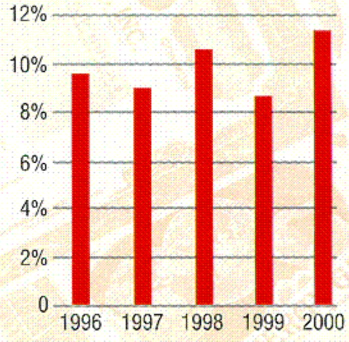
Earnings per Share—Reported
Earnings per Share—Before Nonrecurring Charges
Dividends per Share

Common Stock Market Price and Book Value Per Share



Book Value per Share
Market Price per Share

Return on Average Common Equity



C07

Perspective

The year 2000 was truly a defining period in our 185-year history. From successfully navigating the deregulation of our generation business to announcing our plan to separate our company into two, we took a giant leap forward in our journey to become a world-class, competitive energy business.

Taken together, our accomplishments last year paved the way for continued growth of our business and increasing returns for shareholders. In a year filled with highlights, here are some of the more notable ones:

- In March, the U.S. Nuclear Regulatory Commission granted a 20-year extension of the operating licenses of the two units at our Calvert Cliffs Nuclear Power Plant, making it the first commercial nuclear plant in the country to be granted renewed operating licenses.
- In July, as Maryland opened its electric market to customer choice, our utility generation assets were deregulated and transferred at book value from BGE to our merchant energy subsidiaries. All systems and processes were in place to make it a smooth transition to the competitive energy marketplace.
- In October, we announced a bold plan to separate our corporation into two publicly traded companies to take advantage of the distinct wholesale and retail markets that have evolved as the utility industry deregulates.
- In December, we announced we would become the majority owners of the two Nine Mile Point nuclear power plants in Scriba, New York, a move that will add 1,550 megawatts to our generation portfolio.
- In 2000, we began construction on more than 2,500 megawatts of new, gas-fired merchant plants scheduled to come on line in 2001 and 2002.

2000 Financial Highlights

Our financial results for 2000 reflect a dramatic shift in earnings from the regulated utility business to the nonregulated domestic merchant energy business. This shift began on July 1, 2000, when Maryland's electric industry restructuring law was implemented, and we transferred all of BGE's electric generation assets to our nonregulated subsidiaries.

Christian H. Poindexter

Chairman of the Board and Chief Executive Officer

Reported earnings in 2000 improved to $2.30 from $1.74 in 1999. This increase is primarily due to a nonrecurring charge related to the deregulation of BGE's electric generation business and other nonrecurring charges included in operations in 1999. However, when you exclude these one-time items, earnings from operations for 2000 declined slightly to $2.43 from the $2.48 level achieved in 1999, mostly because of the 6.5 percent electric rate reduction for residential customers effective July 1, 2000.

In addition, the Mid-Atlantic region experienced one of the mildest summers on record in 2000. As a result, in the third quarter of 2000, our residential electric sales were down 11 percent from the same period in 1999.

While earnings were somewhat disappointing, we accomplished much in successfully implementing the Maryland deregulation order and reorganizing our company. We are executing our strategy to grow the earnings contribution of our merchant energy business and are very excited about our future prospects.

In the stock market, the year 2000 was a recovery year for the electric industry—including Constellation Energy. Those companies that have taken a focused approach to growth in a deregulated market performed the best. As the market moved against the technology sector, investors returned to other sectors, favoring traditional companies with proven track records and earnings performance.

Since April 2000, our stock has continued to outperform the S&P and Dow Jones Industrial Average and has remained a favorite among a number of large investment houses.

California's Impact

Yet, as I write this letter, the entire electric industry sector is being influenced by the situation in California. The lack of any significant generating plant construction over the last 15 years, coupled with a rapidly growing economy, has resulted in a severe supply/demand mismatch complete with much higher energy prices in the wholesale market.

In addition, California's laws and regulatory environment have prevented the major utilities from recovering their higher energy costs from their retail consumers, severely eroding their liquidity. At times, this situation has had a chilling effect on the market value of stocks in the electricity sector.

While our stock price has reflected some of the market uncertainty that events in California are causing, our company and Maryland are in a vastly different and much better position. A list on page 8 briefly outlines some of the crucial points that differentiate our situation from California's.

A Defining Move

Over the past decade, we have been keenly aware of what competition is doing to our industry. With all the consolidation in the new markets, we knew we must have the financial strength and access to capital markets to fund our growth plans.

We also have become increasingly aware that moving forward as a combined company in today's world could compromise our market value.

The investment community appears to differentiate energy companies active in the faster-growing wholesale marketplace from those that are either vertically integrated utilities or focused purely on the retail energy delivery and services market. At this time, growth companies, like our merchant energy business, are being awarded higher market multiples in anticipation of the prospect of higher earnings growth rates.

For our company, the plan to separate our businesses is the next logical step in the fulfillment of our two-part strategy that we have articulated over the past three years:

- To be a leader in the wholesale merchant energy business in North America, and
- To provide premier utility and energy-related services in Maryland and its surrounding region.

By separating our company into the new Constellation Energy and BGE Corp., each business can focus on its core expertise and respective customer base. This allows each to compete more fully in its niche of the changing energy marketplace.

This strategy has established a new model for how vertically integrated utilities plan to move forward in the competitive market. At a time when others have chosen to sell off their nonregulated assets, we are the first to announce a complete separation into two stand-alone companies. With imitation being the sincerest form of flattery, other companies are considering or have decided to pursue similar plans.

We are executing our strategy to grow the earnings contribution of our merchant energy business and are very excited about our future prospects.

The New Constellation Energy Focused on Growth

To grow in the wholesale merchant energy arena, a company needs both strength and speed. Our plan to separate quickly advances a very aggressive growth strategy for the new Constellation Energy, our merchant energy business.

Our strength is enhanced by an investment from Goldman Sachs. Since 1997, we have shared a very successful business relationship through the creation of our power marketing operation, Constellation Power Source.

Building on that relationship, we announced in October that we entered into an agreement with Goldman Sachs under which it would become an equity owner of up to 17.5 percent of our merchant energy business.

This exclusive North American power business arrangement will complement our existing merchant energy skills. Also, it will help stimulate an aggressive plan to grow merchant energy earnings per share by 20 to 25 percent a year beginning in 2002.

To match these growth targets, we plan to increase the amount of power under our control from more than 9,000 megawatts today to an estimated 30,000 megawatts over the next five years.

Toward that end, we plan to build more than 7,500 megawatts of power plants in strategic locations across the country by 2005. We will also expand our portfolio through contractual agreements as well as acquisitions, something we have already begun with our purchase of the Nine Mile Point plants.

BGE Corp. Focused on Value

While the new Constellation Energy will fit the risk profile of a high-growth company, BGE Corp. will perform as a more traditional income stock that pays out a significant portion of earnings as dividends. The achievement of a targeted 3 to 5 percent annual earnings growth rate should provide a competitive total return for income-oriented investors.

By leveraging its existing skills and assets going forward, BGE Corp. should be well positioned to prosper.

Upon separation, BGE Corp. will focus on the retail energy needs of our customers, something we have been doing for 185 years. Building off a proud tradition of serving Central Maryland, this company knows the market better than any outside competitor. Plus, it has a well-established and comprehensive platform of businesses that provide the services retail energy customers both want and need. By leveraging its existing skills and assets going forward, BGE Corp. should be well positioned to prosper.

Baltimore Gas and Electric, our regulated energy delivery utility, will be BGE Corp.'s largest subsidiary and biggest contributor to earnings. Serving more than 1.1 million electric and nearly 600,000 gas customers in Central Maryland, it remains the state's largest delivery utility. It intends to continue to be a trusted and valued energy provider to its customers.

BGE Corp.'s core utility business will be augmented by its non-regulated affiliates—BGE HOME and Constellation Energy Source. These businesses already have a strong foothold in the area and provide the full spectrum of competitive energy-related services to a broad retail customer base.

We Begin a New Chapter

Following on the theme from our 1999 Annual Report—"What we call results are just beginnings"—we have indeed begun the newest chapter in our 185-year history.

By mid to late 2001, one company will become two, each with its own stock, its own name, and its own strategy for success. As a result, I believe the sum of Constellation Energy's parts will be greater than the whole.

No doubt, it's been a demanding time and each step has involved risks. Yet, I believe we have put this company where it needs to be to compete in the fast-changing energy marketplace. I am indebted to our employees, whose skill and hard work have positioned both companies to become well-regarded leaders in their respective markets. I am also grateful to the Board of Directors, who had the courage and vision to lead this company to pursue an aggressive but sound growth strategy.

As you read through this report, you'll learn more about the power of the two new companies we are creating. Based on the strength of our companies and the soundness of our strategy, we have much to look forward to in the year ahead.

Sincerely,

Christian H. Poindexter
Chairman and Chief Executive Officer
February 15, 2001

Q+A Your Questions

How does the separation plan affect my stock and dividends?

Your stock

First, there is nothing you need to do with your existing stock. When we separate, you will own shares of stock in both companies. We will be sending you more information on this process as we get closer to the separation.

From purely an investment perspective, the separation is good news because it expands investment options. Our new merchant energy business would likely appeal to investors who are growth-oriented and tolerant of more risk. BGE Corp. would likely appeal to our more traditional investor interested in income and more stable returns.

Investors will need to make decisions on what to do with their shares of stock based on how they assess each company's balance of risk and return.

Your dividends

For our merchant energy business, we have set ambitious earnings targets, to be driven by a rapid nationwide expansion in power generation. To fund this aggressive growth plan, we have changed the annual dividend policy. Effective April 2001, our annual dividend will be $.48 per share, reflecting an appropriate payout for BGE Corp. as a stand-alone company.

After separation, BGE Corp. expects to pay out dividends similar to other premier companies in the retail energy sector. The new Constellation Energy will not pay a dividend initially, reinvesting its earnings to fund its growth plans.

We understand how important the income from dividends is to a number of our shareholders. We announced our intention to change the dividend policy in October 2000 so we could give shareholders enough time to consult with their financial advisors and determine the best course of action.

Can California Short-Circuit Maryland?

Is the situation that has driven California's utilities deep into debt and threatened the state's power supply likely to be repeated in Maryland? The chances are remote because of some fundamental differences between the two states.

California often leads the nation in setting trends. It was the first state to deregulate, and its model has now become a blueprint for how not to move to a competitive power market. Maryland recognized key flaws in California's model and determined not to duplicate them.

But more important, California's electricity market is plagued by a lack of adequate supply to meet demand. Maryland does not have that problem. As part of the cohesive PJM (Pennsylvania-New Jersey-Maryland) Interconnection, the well-established power pool in the Mid-Atlantic area, Maryland benefits from the 19 percent reserve margin PJM requires.

Here are some of the other key differences between the two states' situations:

California

- Supply has lagged far behind demand. During peak periods in January 2001, reserves fell to less than 1.5%. A widespread system breakdown was averted in January by resorting to rolling blackouts.
- Electric demand is expected to grow by 1.7% over the next 10 years. Almost 10,000 megawatts (MW) of new generation is needed by 2003 to meet a 15% reserve margin. About 6,300 MW have been permitted; about 4,300 MW are under construction.
- The last significant power plant built in California was in 1986. It has been difficult to permit power plants in the state because of a cumbersome approval process for plant construction.
- The Independent System Operator (ISO) power pool is one of the country's newest. Regulators are adjusting price caps and market rules that discourage new generation.
- The ISO controls only the investor-owned utilities' portion of the transmission system, not the entire state. This limits its ability to maximize system efficiency and makes it difficult to respond to emergencies.
- California utilities have relied heavily on the spot market to purchase electricity, exposing the utilities and customers to volatile energy prices.
- A compressed time frame for the transition to competition has not allowed adequate time for the market to mature.
- Electric supply depends partially on out-of-state generators, including inexpensive hydro plants. Last summer's drought and lack of significant snow in the West has restricted hydro output.

Maryland

- Supply is adequate in the Maryland/PJM region. The projected reserves in the region for this summer are 21.6%. Thus, resources committed to serve PJM load meet the power pool's reserve obligation of 19%.
- Electric demand growth in the PJM region is expected to average 1.4% over the next decade. Although PJM peak load is expected to grow by 2,270 MW by 2003, almost 2,600 MW of new generating capacity will be added before summer 2001.
- According to PJM, the region has added about 4,500 MW over the past decade and has another 6,800 MW under construction or in the final stages of permitting to come on line by 2003. The plant construction permitting process is more streamlined.
- PJM is the most established power pool in the country, and the region's wholesale market is stable. Rules don't discourage building new generation.
- All transmission is under PJM's control. Significant power imports are not normally needed to meet load, but the system can respond to emergencies.
- Maryland utilities' energy supply relies on a more balanced approach, concentrating on more long-term, fixed-price contracts to supply customers.
- A six-year transition to competition for BGE residential customers allows the market time to mature.
- Maryland and the PJM system have much less reliance on hydro plants than do West Coast states. Generation supply is less linked to such factors as rainfall and snowmelt.

C08

TWO POWERFUL MANAGEMENT TEAMS

People 2 Watch

In the eight years he has been in charge, Chris Poindexter has pursued with unwavering resolve the goal of preparing the nation's oldest utility to face the new challenges of competition. Now he's making his boldest move yet—splitting the 185-year-old company into two. Here's a look at the management teams in place to lead each company.

Growing the Merchant Energy Business

When the separation is completed, **Chris Poindexter** will continue to serve as chairman and CEO of the new Constellation Energy Group, a national merchant energy business.

Joining him as co-presidents of the current as well as the new Constellation Energy are **Chuck Shivery**, who has been in charge of Constellation Power Source Holdings, and **Eric Grubman**, who joined Constellation Energy last October from Goldman Sachs.

Under Shivery's leadership, Constellation Power Source has grown from a start-up merchant energy company to a leading power marketer in North America. Grubman was a senior-level investment banker with broad experience in mergers and acquisitions and the energy industry before he joined Constellation Energy.

"This co-president team has brought together individuals with strong, complementary skills that already have enabled us to grow quickly," says Poindexter.

"Together they make a powerful team that combines both strong operational know-how with well-developed skills in mergers and acquisitions," Poindexter adds. "These qualities will serve us well as we continue to grow Constellation Energy into a top merchant energy business."

Developing a Strong Retail Services Business

With separation, BGE Corp. will become the parent of the company's utility and retail energy services businesses. Chosen to take over the helm of BGE Corp. as chairman, president, and CEO is Constellation Energy Vice Chairman **Ed Crooke**.

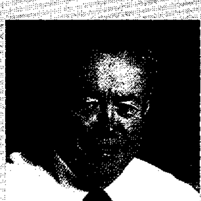
After retiring in January 2000, Crooke remained active on Constellation Energy's Board of Directors and continued to be instrumental in shaping the company's growth and retail strategies. Since returning to active service in October 2000, he has focused on the smooth execution of the separation plan and on creating BGE Corp.

BGE President and CEO **Frank Heintz** will continue in that position after separation. **Tom Brady**, now Constellation Energy's VP of Corporate Strategy & Development and in charge of the company's nonregulated retail businesses, will become BGE Corp.'s chief financial officer and continue to lead its nonregulated businesses.

"Under Frank's leadership, BGE managed a very smooth transition to retail customer choice, while Tom was instrumental in constructing our separation plan," says Crooke. "Between the two of them, I have a powerful team that can take BGE Corp. to new heights in the retail energy services market."

AFTER THE SEPARATION

Constellation Energy Group

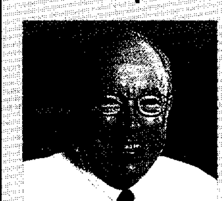


Chris Poindexter
Chairman & CEO

Chuck Shivery
Co-President

Eric Grubman
Co-President

BGE Corp.

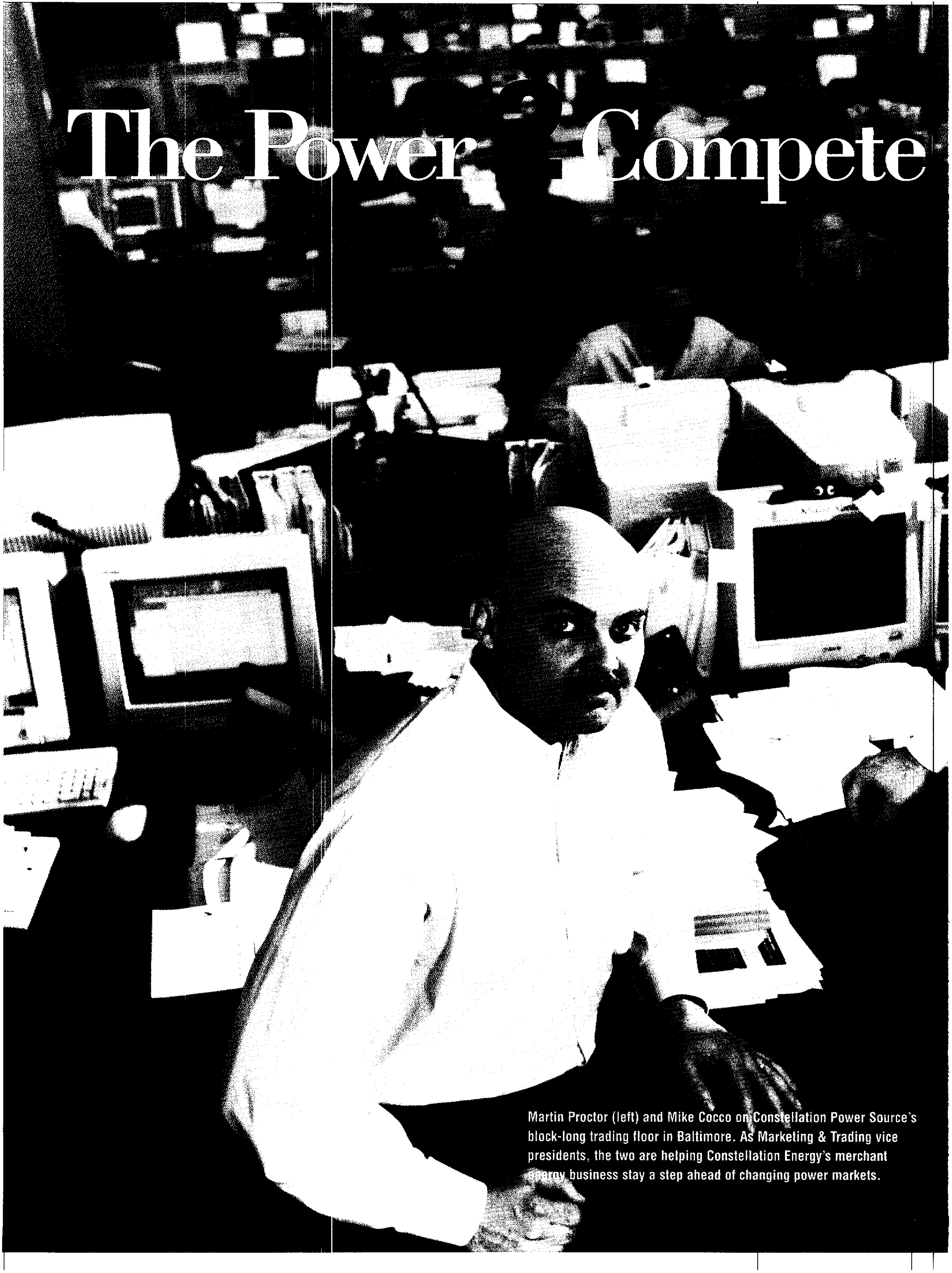


Ed Crooke
Chairman, President, & CEO

Frank Heintz
President & CEO, BGE

Tom Brady
CFO, BGE Corp.

The Power Compete



Martin Proctor (left) and Mike Cocco on Constellation Power Source's block-long trading floor in Baltimore. As Marketing & Trading vice presidents, the two are helping Constellation Energy's merchant energy business stay a step ahead of changing power markets.

The Power 2 Compete

Martin Proctor (left) and Mike Cocco of Constellation Power Source's block-long trading floor in Baltimore. As Marketing & Trading vice presidents, the two are helping Constellation Energy's merchant [illegible] business stay a step ahead of changing power markets.

Electric deregulation continues to create opportunities in the dynamic wholesale power market. With the right pieces in place, Constellation Energy is taking advantage of those opportunities with a merchant energy business that's built to last.

Martin Proctor is in wholesale power for the long run.

As the West Coast marketing VP for Constellation Energy's affiliate, Constellation Power Source, Proctor spends most of his time thinking ahead—working with utilities, power marketers, and municipalities on contracts that will help them meet the energy needs of their customers for years to come.

That means Proctor isn't just operating three hours in front of his left coast contacts—he's years ahead.

"When you're looking at a power contract for five or seven years, you're looking at volatility and risk," says Proctor. "What Constellation Power Source does best is identify and articulate the range of risks—weather, market changes, deliverability issues—all the things that can affect prices for our customers," he continues. "If you can quantify the risks, you can work around them, but that means always staying a step ahead."

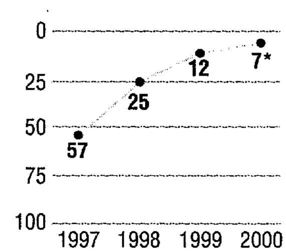
A step ahead is exactly where Proctor and Constellation Energy's merchant energy business are.

Pulling together the fruits of years of competitive preparation, Constellation Energy is executing its plan to build and maintain one of the top merchant energy businesses in the country. Its Constellation Power Source affiliate now combines a top-ranked marketing and trading group and Goldman Sachs' risk management systems with experienced power plant operations and development, and a solid and diverse generation portfolio.

Add to that more than 7,500 megawatts of new power plants planned for strategic growth areas across the country and the strategy to separate later this year, and you can see Constellation Energy's merchant energy business is built for success for the long haul.

"We've got the whole package together now," says Constellation Energy Group Co-President Chuck Shivery. "We have a clear direction. We know where we want to go and how we're going to get there. If we do it right, and I believe we will, we'll be one of the premier merchant energy companies in the country—for the long term."

Constellation Power Source Power Marketer Rankings



** Ranking for the year as of third quarter 2000, the last data available at time of publication.*

Based on** Power Markets Weekly**, an industry publication, Constellation Power Source has moved from 57th to one of the top-ranked U.S. power marketers in less than four years.

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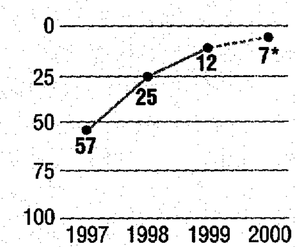
Constellation Power Source Power Marketer Rankings



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Based on *Power Markets Weekly*, an industry publication, Constellation Power Source has moved from 57th to one of the top-ranked U.S. power marketers in less than four years.

separate later this year, and you can see Constellation Energy's merchant energy business is built for success for the long haul.

"We've got the whole package together now," says Constellation Energy Group Co-President Chuck Shivery. "We have a clear direction. We know where we want to go and how we're going to get there. If we do it right, and I believe we will, we'll be one of the premier merchant energy companies in the country—for the long term."

Making Strategic Sense of a Growing Market

While opportunity is everywhere in the new energy landscape, knowing which markets are right for your business is the key to success.

For Constellation Power Source, making sense of growing opportunities in the 10 North American regional power markets means constantly searching the energy horizon, checking your business strategy, and asking a lot of questions that begin with "what if…".

What if demand drops? What if the regulatory environment changes? What if we build a plant? What if we contract for power?

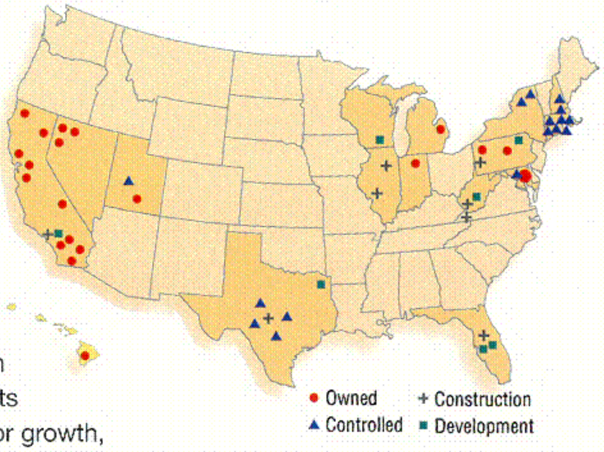
"Not every region is right for us," says Constellation Power Source Managing Director of Strategic Planning Diane Featherstone. "It has to make strategic sense if we're going to commit capital and time."

Featherstone describes strategic sense as a not-too-distant cousin of supply and demand. Choosing the right regional markets, she says, consists of looking for the right characteristics. "We're continuously evaluating their regulatory and political environments, measuring energy demand growth, determining the availabilty and price of fuels, and analyzing what the competition is doing. If the numbers add up and the market looks right, then opportunity might bloom," says Featherstone.

While Constellation Power Source is doing business in almost every North American region from the South to the Mid-Atlantic to the West, there's no cookie-cutter approach to power markets.

"The continuous decision we're making is which markets offer the best opportunities for growth, and what business should we be doing in them," Featherstone adds. "It changes constantly.

"Summer electric demand has grown 24 percent in the U.S. since 1992, while capacity has only grown by about 6 percent, so there are opportunities out there," adds Featherstone. "Our job is to make sure Constellation Power Source is in the right place and has the right position to take advantage of it."

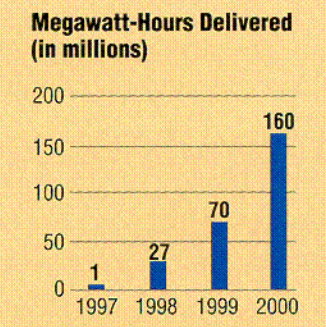


Constellation Energy owns, controls, and is developing energy projects in markets that make strategic sense to grow the business.

The Energy 2 Grow—Marketing & Trading

Spend a little time on Constellation Power Source's trading floor in Baltimore and you can feel the power surging.

The nucleus of the Constellation Power Source merchant energy business, the trading floor is the place where real time meets the future in fast forward. Nearly 200 power marketers and traders gather daily on the 10,000-square-foot floor to work multiple computer screens and phones, keeping one eye on the weather, another on fuel markets, one foot in today, one in tomorrow.



From 1999 to 2000, Constellation Power Source more than doubled the number of megawatt-hours it delivered to wholesale energy customers across North America.

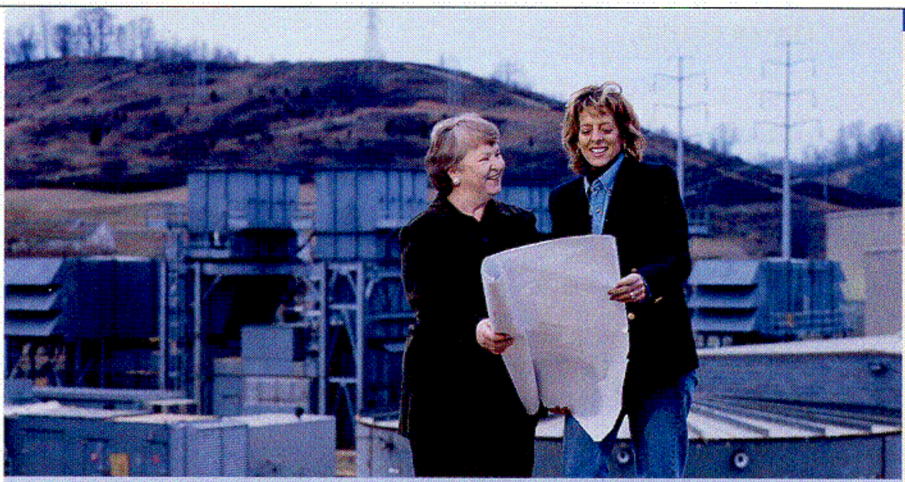
"The trading floor is the trenches," says Mike Cocco, Vice President of Trading for Constellation Power Source. "Our marketers find out what a customer's power needs are and how we can meet them. But the traders are always behind them—managing the risk, buying, and selling. We're talking about anything from small amounts of power in real time to a structured deal of 100 million megawatt-hours over 10 or 15 years."

After finishing its initial year in 1997 as the 57th ranked power marketer in the United States, Constellation Power Source in 2000 moved up with a burst of energy. Fueled by the addition of more than 6,200 megawatts of electricity brought over from the regulated side of the business last year, Marketing & Trading more than doubled the amount of electricity it delivered—from 70 million megawatt-hours in 1999 to 160 million megawatt-hours in 2000.

Add to that success a more focused future with more power to back up marketing and trading, and you can feel the energy levels rise another notch.

"Look at the pieces we've put together," adds Dale Meyer, a Trading Division VP for Constellation Power Source. "With the risk management experience we've developed through our relationship with Goldman Sachs, our top-quality marketers and traders, and a growing generation portfolio to back us up, our marketing and trading operation is powerful."

C09



Gina Molz (right), a Constellation Power Source developer, built a strong relationship with the community, including Dulcie Mumpower (left), a representative of the Washington County (VA) Board of Supervisors, before moving ahead with plans to construct the Wolf Hills Energy peaking plant in Bristol, Virginia.

Meeting Market and Community Needs

With short power supply, growing demand, and limited transmission access, the green hills of Bristol, Virginia, near the Tennessee border fit Constellation Energy's strategic profile for building generating plants in markets where it makes sense.

But before the first shovel hit the ground for the planned Wolf Hills power plant in Bristol, Constellation Energy made sure the plant made sense for the community, too.

"I was a little concerned when I first heard about a power plant in our area," says Dulcie Mumpower, who lives just east of the Wolf Hills property. As a member of the Washington County, Virginia, Board of Supervisors, she represents the district where the plant is located.

"But I did the research and saw the economic benefits, the added power supply, and the limited environmental impact the plant would have," Mumpower continues. "Then I met the people from Constellation Energy, and it was obvious they know what they're doing and they care about the communities where they operate. I realized this was a project that would benefit us both."

Peaking Interest

A 250-megawatt natural-gas-fired plant, Wolf Hills is one of four "peaking" plants Constellation Energy will bring online in 2001. "Peakers" are designed to operate primarily when electricity demand is highest. Other peakers are under construction in West Virginia, Central Pennsylvania, and outside Chicago, Illinois. Several larger combined-cycle power plants are also under construction in Illinois and Texas.

In all, Constellation Energy has plans to build more than 7,500 megawatts of new power plants by 2005 to support the company's growing merchant energy business.

"Building power plants is only one piece of our growth strategy," says Constellation Energy Co-President Eric Grubman. "But to succeed as a merchant energy company, in some markets you need the physical generating assets to back up your business. Wolf Hills was a perfect fit for us and for the surrounding community. That's what we mean by making sense."

Earning Your Environmental Trust

To earn a community's environmental trust, you've got to walk the walk and talk the talk.

Constellation Energy last year talked and walked with residents living near its Brandon Shores power plant as they teamed to resolve a mutual environmental concern.

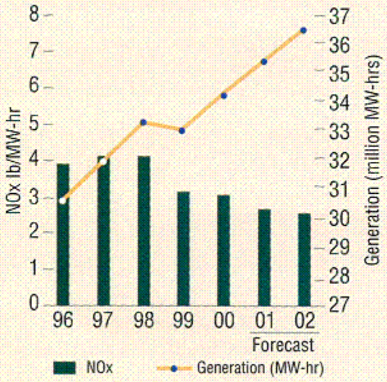
To comply with Maryland Department of Environment requirements for 2001, Constellation Energy is installing Selective Catalytic Reduction (SCR) technology at the coal-fired plant located outside of Baltimore. SCRs, which work like a car's catalytic converter, use ammonia to break down emissions into harmless gases.

After announcing plans to use anhydrous (without water) ammonia for its SCR system, the company heard community concerns about the need to transport and store the ammonia. So they talked—joining with community leaders to form a working group that discussed the alternatives. In the end, the group collectively decided to change to a less-concentrated 30-percent ammonia liquid.

The result—SCRs will begin operating in May 2001, reducing the plant's nitrogen oxide emissions by 90 percent and making Brandon Shores the cleanest coal-fired plant of its size in the country. As for the community, they were satisfied with the result and have decided to keep the group together to keep talking and walking with Constellation Energy.

"We listened to each other, we explained our needs, and we heard their concerns," says Bonnie Johansen, a senior environmental scientist with Constellation Energy. "Protecting the environment is a group effort. By working together, we can achieve the right results for everyone involved."

Nitrogen Oxide (NOx) Emissions vs. Constellation's Net Generation in Maryland



Over the past five years, Constellation Energy's Maryland plants have increased output while reducing the amount of nitrogen oxides emitted in the air, meeting or exceeding the standards set by the federal Clean Air Act.

C10

Fuel Diversity Generates Success

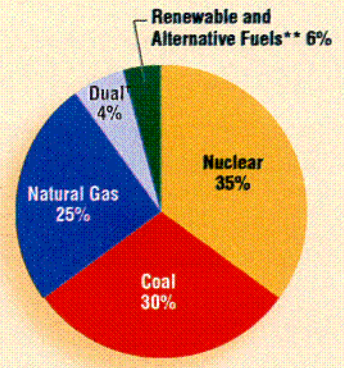
The operative word behind power marketing is "power." To meet wholesale customers' energy needs you have to have the energy to back up your business or you might as well pull the plug. But just as important as the megawatts is the price. To ensure you're not at the mercy of the market, you need a range of fuels powering your plants.

Constellation Energy's customers have long benefited from a diverse generation portfolio. Today, the company controls more than 9,000 megawatts of power covering a range of fuels from coal to nuclear to alternatives such as solar and geothermal. It's a balanced mix that the company intends to maintain as it grows.

Grow it will. Through a combination of ownership and contractual control, and a commitment to build new plants in growing markets, Constellation Energy plans to control around 30,000 megawatts of power across the country by 2005.

That's a lot of power that can generate a lot of success.

Constellation Energy's Fuel Mix
*Generation Owned At Year-end 2001**



* Includes addition of new gas-fired peaking units and Nine Mile Point nuclear units.
** Renewable and alternative fuels—as defined in Maryland—includes solar, wind, geothermal, hydro, biomass, and waste-to-energy.
† Switches between natural gas and oil.

Constellation Energy owns a generation portfolio that is fueled by a diverse mix including fossil, natural gas, nuclear energy, and alternative fuels.

Fossil Power Goes to Market

July 1, 2000, was moving day for 4,500 megawatts of fossil and hydro power and 900 experienced employees from BGE. As part of the start of electric deregulation in Maryland, BGE's power plants and people moved from a regulatory home to the unregulated wholesale power market, a shift that was more like a move around the corner than one around the world.

"Our objective has been and continues to be operating our plants to meet customer's requirements," says Wayne Seifert, VP of Baltimore Operations for Constellation Power Source Generation. "What changed when we moved to the unregulated market was our customer. Now our customer is Constellation Power Source Marketing & Trading. Now we have to be ready to generate when they need us to satisfy a wholesale customer's requirements."

They'll be ready. In 2000, Constellation Power Source's fossil energy plants produced 18.3 million megawatts of power and did it safely. In addition, the plants continued to produce power at competitive costs.

"This is a new start for our fossil generating plants," adds Seifert. "We look at ourselves as part of the growth engine for this company—kind of the power behind the source."

First in the Nation

The Calvert Cliffs Nuclear Power Plant last year made more than megawatts—it made history. In March 2000, Constellation Energy's Calvert Cliffs Nuclear Power Plant became the first nuclear facility in the country to have its operating licenses renewed.

Calvert Cliffs' success was at the forefront of a year in which nuclear power re-emerged in the public eye as a safe, economical, and viable energy source. In 2000, the Nuclear Energy Institute, a policy organization for the industry, reported that for the first time in over a decade, production costs at U.S. nuclear plants were the lowest of any major reliable electricity source. Also, including Calvert Cliffs, five units have received renewed operating licenses. Applications for license extensions for 33 more reactors have been or are expected to be submitted to the Nuclear Regulatory Commission by 2004.

Being first has its advantages. Calvert Cliffs' historic renewal was spearheaded by many of the same people who now run a Constellation Nuclear subsidiary, Constellation Nuclear Services (CNS), a consulting business that specializes in nuclear power plant license renewal and life-cycle management. CNS now has contracts with many of the plants seeking relicensing.

In March 2000, Constellation Energy's 1,700-megawatt Calvert Cliffs Nuclear Power Plant on the Chesapeake Bay became the first nuclear facility in the country to have its operating licenses renewed. The plant's two units now have 20 additional years of operating life through 2034 and 2036.

C11

Nuclear Power Strengthens the Mix

Nuclear power has been in Constellation Energy's generation mix for more than 25 years, and it's staying there. For good reason.

Already recognized as one of the top nuclear plants in the country, Constellation Energy's Calvert Cliffs Nuclear Power Plant generated record results in 2000—producing 13.8 million megawatt-hours of electricity. Also, for the fifth consecutive year, Calvert Cliffs ranked among leading nuclear plants for worker safety as measured by the Occupational Safety and Health Administration.

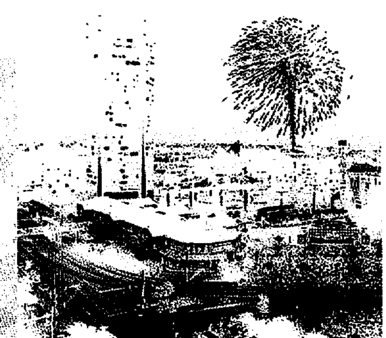
"It's critical to maintain a diverse fuel mix in the competitive power market," says Bob Denton, President and CEO of Constellation Energy affiliate Constellation Nuclear. "Fuel diversity allows us to manage price risk and meet long-term power commitments better. That's the kind of strength nuclear power brings to our generation portfolio."

Constellation Energy's nuclear component was strengthened even more when the company announced in December 2000 that it would purchase 100 percent of Unit 1 and 82 percent of Unit 2 of the Nine Mile Point nuclear power plants in Scriba, New York. The purchase will add another 1,550 megawatts of nuclear power to the generation portfolio that backs up the merchant energy business.

"We've proven for a number of years that we can operate at the top of the nuclear industry," adds Denton. "We're ready to continue to do that and help our merchant energy business grow."

> **"Fuel diversity allows you to manage price risk and meet long-term power commitments better. That's the kind of strength nuclear power brings to our generation portfolio."**
>
> —Bob Denton, President and CEO, Constellation Nuclear

The Power 2 Deliver



When Constellation Energy separates, the company's retail energy customers will be served by BGE Corp. Between its regulated utility, BGE, and its unregulated energy services businesses, BGE HOME and Constellation Energy Source, BGE Corp. will provide the energy and the services retail customers want and need.

"In this region, we have a clear strategic advantage as a retail energy services business. We know this market and where the opportunities exist. We know our customers, and they know us. And we know our business and what it takes to be a winner." *Ed Crooke, Vice Chairman, Constellation Energy*

Energy and More

Baltimore will soon be home to a new, $4 billion corporate citizen. Welcome the new BGE Corp., a regional, integrated energy delivery and retail services enterprise. Despite the familiar sound of its name, BGE Corp. will be more than the traditional utility company that Marylanders have come to know over the years.

"As a result of the business separation, BGE Corp. will be able to focus on what it does best—deliver energy and energy services to our retail customers and stability and value to our shareholders," says Ed Crooke, Constellation Energy vice chairman and soon to be BGE Corp. chairman, president, and CEO after separation.

Leveraging the Right Business Mix

Three key companies form the platform from which BGE Corp. will operate in the retail energy sales sector: Baltimore Gas and Electric (BGE), the regulated utility that delivers gas and electricity throughout Central Maryland; Constellation Energy Source (CESource), which specializes in providing customized energy solutions to commercial and industrial customers based primarily in the Mid-Atlantic region; and BGE HOME, which offers competitive energy products and services to residential and commercial customers primarily in Maryland.

Providing the principal source of revenue, BGE stands out as the premier energy delivery company in the region. With more than $3 billion of pipes and wires network and equipment, it maintains a reliable infrastructure that connects the company to nearly 2.6 million people living in the service territory.

"BGE will continue to build on its 185-year tradition of providing outstanding service as North America's first and oldest utility," says BGE President Frank Heintz. "Every BGE employee is focused on our mission to safely, economically, reliably, and profitably deliver gas and electricity to our customers in Central Maryland."

While BGE's contribution is significant, the biggest opportunity for growth is on the unregulated side. There, BGE HOME and CESource have proven to be strong contenders in one of the industry's most competitive sectors—retail energy services. In markets where margins are slim and the competition is wide, each has leveraged its strengths and made a solid niche for itself within the region.

The Advantage of Good Timing

Today, Maryland is one of only 12 states to have fully deregulated its retail electric supply business and one of 11 to do so on the gas side. While the retail energy market has been slow to emerge, energy experts expect to see the retail energy services business evolve significantly over the next five years as more states deregulate and the market matures.

"We have the advantage of operating in a state that was not one of the first to deregulate, but was ahead of the pack," says Tom Brady, Constellation Energy VP of Strategy & Development and soon to be BGE Corp.'s chief financial officer and in charge of its nonregulated retail businesses. "That way we have been able to see what has and has not worked in other regions and had time to put in place the services that make sense for our market, our skills, and our assets.

"By making smart choices and using our experience in local markets, we have developed a strong platform of businesses that deliver the energy services we know our retail customers want. That gives us an advantage going forward," says Brady.

"But this is a rapidly changing market and new opportunities will likely develop as it matures," adds Crooke. "If there's a new venture that makes sense for our business and skills and increases shareholder value, our companies will aggressively pursue it."

Energizing Baltimore

Gas Operations Manager Darlene Buchholz and New Business & Distribution Construction Manager Johnny Magwood are two people who literally have the power to energize Downtown Baltimore.

In the middle of what it's calling a second renaissance, Baltimore is expanding its thriving downtown tourist and business district eastward. Working with the planners and developers, Buchholz, Magwood, and their high-performance teams have made sure Baltimore's East Side has the gas and electric infrastructure it needs to grow.

BGE Changes With Time But Remains Your Energy Delivery Company

For Baltimore Gas and Electric Company, last year was one for the history books. After more than 90 years operating as a vertically integrated monopoly, BGE became strictly an energy delivery utility in July when Maryland deregulated the electric supply part of the industry.

When the electric market opened to retail customer choice, BGE was ready. It had already successfully opened its natural gas distribution system, first to industrial customers in 1984 and then fully to retail residential and commercial customers in November 1999.

Following suit on the electric side, BGE had all systems, procedures, and communications in place.

To execute a smooth transition, more than 200 employees and systems consultants spent more than 30,000 workdays developing and testing the new systems and business processes needed. They had developed all new billing arrangements for customers and a whole new system for the competitive power suppliers. They designed the process for how suppliers would enroll customers and the system to exchange vital information between the utility, suppliers, and the PJM (Pennsylvania-New Jersey-Maryland) power pool.

Plus, they launched an extensive communication campaign to inform and educate BGE's residential and business customers and suppliers about the changes that would affect them. Residential and general business customers received educational bill inserts and brochures. Telephone representatives were ready to answer a range of deregulation questions from customers, and print ads carried the message to audiences-at-large.

"It was a monumental effort, yet well worth it when you see how smoothly we ushered in the new era of customer choice," says BGE President and CEO Frank Heintz.

Delivering Reliability

Talk to any of the nearly 3,700 BGE employees about deregulation and all will agree it was significant. Ask how it has changed what they do and you'll likely hear another story.

"The work is changing, that's inevitable," says Johnny Magwood, BGE Manager of New Business & Distribution Construction. "But with or without deregulation, we still work 24/7 doing whatever it takes to reliably deliver energy over our pipes and wires."

"No doubt, next to price, service reliability still ranks highest in customers' expectations from an energy delivery company," says Charlie Welsh, BGE's Director of Market Research. "But today's digital world has raised the bar for electric system reliability. One split second interruption can do anything from make your VCR's clock blink to shut down a whole production line. People expect high-quality system performance and don't want to put up with less."

Meeting those high standards has been the motivation behind BGE's initiatives to improve system reliability. Investing more than $350 million in the past six years, BGE has instituted a comprehensive program to prevent outages. The efforts are paying off. "Since 1994, our average number of annual sustained interruptions per customer has been reduced by 40 percent," says John Borkoski, who leads BGE's Reliability & Maintenance Planning group.

SWAT Team Delivers Results

Statistics bear out that BGE's strategies have been working on a system-wide basis. Yet, there remained a few pockets where customers were experiencing more than their fair share of outages.

Last year, a team from the Electric Transmission & Distribution division took a SWAT-team approach to improve reliability in those areas. Because of this and other efforts, the company had its best year in nearly two decades for reliability.

"We performed additional inspections and maintenance, did extensive tree-trimming, replaced underground cables, and even redesigned parts of the system—all to ensure that customers received the most reliable service," says Mike LeSavage, who is in charge of BGE's Customer Reliability Assurance section.

"I'm proud of the teamwork that went into the effort to improve our delivery system. Ultimately, we improved the electric service for our customers, and that's what counts."

Room to Grow With Gas

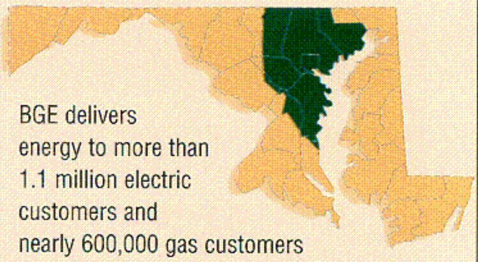
Despite the volatile gas prices this past winter, customers continue to request gas service because it's clean, affordable, and dependable.

BGE delivers gas to about 52 percent of its total electric customer base through a gas system that extends throughout more than 800 square miles. Within its gas territory, BGE's gas business has captured 55 percent of the customers, leaving room for significant growth.

For most of the past decade, BGE has focused on expanding the gas delivery system to meet the growing demand. Targeting areas where there's high residential growth and industrial and commercial demand, BGE has added more than 1,200 miles of gas main and more than 57,000 customers to the system in the past six years.

The company has seen returns on its investment. Since 1994, earnings from the gas delivery business have grown by 12 percent. BGE intends to continue that trend and further expand its gas distribution system.

BGE's Energy Delivery Business at a Glance



BGE delivers energy to more than 1.1 million electric customers and nearly 600,000 gas customers throughout Central Maryland. Here's a quick glance at its operations:

Electric Transmission and Distribution

- Delivers electricity throughout its 2,300-square-mile service territory through its transmission and distribution system and is a member of the PJM Interconnection, the region's power pool.
- Maintains 21,819 circuit miles of distribution lines rated 34.5 kilovolt and below and 1,297 circuit miles of transmission lines rated 115 kilovolt and above.

Gas Distribution

- Stores and delivers natural gas through two peak-shaving plants, nine gate stations, and nearly 5,870 miles of gas main in an 800-square-mile service territory.
- Natural gas suppliers include Columbia Gas Transmission Corporation, Transcontinental Gas Pipeline Corporation, and Dominion Transmission.

Betty Ferguson knows first hand what new technology can do to improve her business. In charge of BGE's Customer Call Center, she manages the 185 representatives who answer the more than 4.5 million calls that come in annually.

New Number Means Faster Service

On an average day, BGE call center reps respond to about 10,000 calls. During a major storm, however, that number can increase tenfold. Given that volume, you need a phone system that can ensure all customers' calls are answered and service outages are reported quickly, even during the most catastrophic of events.

That's why BGE installed a new automated outage-reporting system last summer. With a dedicated toll-free telephone number, the high-volume call answering system can answer up to 100,000 calls an hour during an emergency.

Now customers are encouraged to call 1-877-778-2222 to report power outages.

"Not only is it easy to remember," says Betty Ferguson, Manager of BGE's Customer Care department, "but more importantly, when customers use the new number, we can diagnose the problem and dispatch crews faster. That means it takes less time to restore customers' power, which is the bottom-line result we're looking for."

C12

A Touchdown With the Steelers

CESource President Greg Jarosinski and Dan Rooney, president of the Pittsburgh Steelers, stand in front of a rendering of Pittsburgh's new football stadium.

"We wanted a first-class company with a proven record to manage the energy needs of our new world-class stadium," Rooney says. "We're glad to have CESource on our team."

Constellation Energy Source Scores With Deregulation

Mention electric deregulation to Greg Jarosinski and he gets excited; he sees a business opportunity. That's because as president of Constellation Energy Source (CESource), he can offer customized energy solutions to commercial and industrial customers.

"Deregulation has opened a lot of doors because customers are more concerned now about operating costs," says Jarosinski.

The energy services market in the United States is estimated to grow to $43 billion by 2005, up from about $25 billion in 1999, according to a market survey by Frost and Sullivan, a trade industry research company. "There is more than enough work in this region to keep us busy," Jarosinski notes.

Companies Seek Solutions

As more companies recognize the need to contain their energy costs, they are increasingly relying on the expertise of energy services companies. That's where Jarosinski and CESource enter the picture. The company's 43 employees provide a wide variety of technical and mechanical expertise to meet the energy needs of clients.

CESource services help contain and reduce operating and maintenance costs, delay capital expenditures, extend equipment life, reduce cost per unit of production, minimize downtime, and improve quality.

CESource has completed hundreds of customized projects, including services for heavy industry, health care, higher education, government, and property management.

Regional Business, National Clients

Among its impressive list of customers are the U.S. operations of McCormick & Co., the more than 250 properties of The Rouse Co., the Social Security headquarters in Woodlawn, Maryland, the national malls of the Mills Corp., the Digital Harbor Development in Baltimore, and the Jos. A. Bank Clothiers Co.

The U.S. Department of Energy selected CESource as one of five companies to manage a national $500 million geothermal energy-saving retrofit program for federal facilities.

Although CESource focuses its services in the Mid-Atlantic region, it has established strong relationships with local customers having a large regional or national presence. It scored a touchdown last year when it was awarded an energy management contract for the new Pittsburgh Steelers football stadium, a facility under construction that will replace Three Rivers Stadium.

"The only way to manage energy costs in a deregulated market is to have a comprehensive, energy-efficiency plan,"Jarosinski declared. "We're developing solutions to help our customers improve their bottom line."

Separation Equals Growth

Upon the separation of Constellation Energy Group businesses, CESource will become a subsidiary of BGE Corp. In that role, it is expected to generate a significant portion of the corporation's growth.

"The business separation will mean increased financial and management support from BGE Corp., and the ability to attract outside investment," Jarosinski says. "We will have all the pieces in place to grow the business at a time when customers are looking for solutions.

"Clearly, electric deregulation has put an extra spark in our business."

BGE HOME Delivers Impressive Energy Services Lineup

Bill Munn, President and CEO of BGE HOME, is as competitive running the company as he was playing center on the basketball team at Tufts University.

"In many ways, the retail energy services business is like a basketball game," Munn says. "To win, you must be prepared and disciplined. And when you see an opportunity, you must move in quickly."

A Team With Depth
BGE HOME, along with Constellation Energy Source, will provide real growth opportunities for BGE Corp.

BGE HOME is committed to offering the residential community the most efficient and cost-effective solutions to meet their home comfort needs. To do that, BGE HOME offers an impressive platform of products and services—including gas commodity, appliance and home electronics sales and service, home improvement, heating and air conditioning sales and service, and much more.

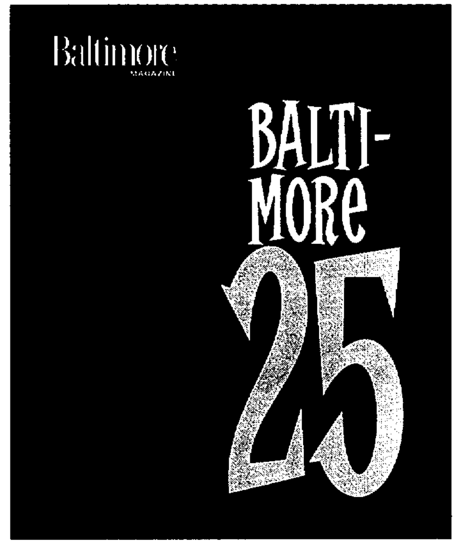
BGE Commercial Building Systems, a subsidiary of BGE HOME, is a full-service mechanical systems company specializing in total building solutions for the commercial market. They also supply the energy that makes the buildings function. Some projects they've worked on in the past year include Towson University's Administrative Building, the Hilton at BWI Airport, and even a renovation of the White House's Eisenhower Wing.

Seizing the Gas Initiative
BGE HOME strives to ensure that a customer's first contact with the company is the beginning of a long relationship, offering an extensive menu of products and services that few competitors can match.

There is no better example of capitalizing on opportunity than BGE HOME's accomplishments in the deregulated gas market. Since Maryland's residential market opened in November 1999, the company has captured a significant portion of the customers who switched within BGE HOME's primary target market.

"Getting gas customers is only the first step," Munn declares. "Once we have acquired a customer, we can enhance our relationship by introducing complementary products and services.

"In the future, the winners in the deregulated marketplace will be determined by the delivery of the value-added products and services they provide, not by the pure sale of the commodity itself," Munn adds. "Our mission is to develop long-term relationships with our customers by providing them with the energy solutions they need."



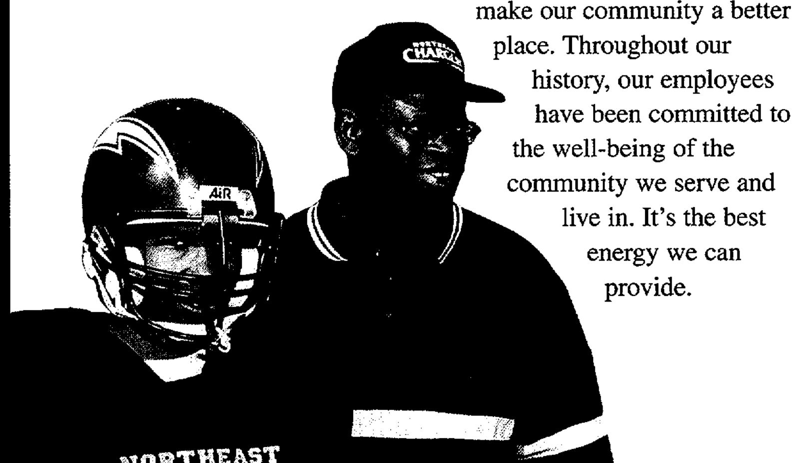
Best of Baltimore
BGE HOME's plumbing operations and retail stores have been named the "Best of Baltimore" by *Baltimore Magazine.*

VOLUNTEERS: THE BEST ENERGY WE CAN PROVIDE • VOLUNTEERS: THE BEST ENERGY WE CAN PROVIDE

The **Energy** to **Serve**

Andy Adams does more than serve his customers, he serves his community. Seen here with a player from the Pop Warner football team he coaches, the material handler with BGE HOME also volunteers his time mentoring children, serving on the Board of Directors for the Coalition for Homeless Children and Families, and running BGE HOME's volunteer program.

We sincerely thank Andy and the hundreds of other employees who see a need and donate thousands of hours of their own time to make our community a better place. Throughout our history, our employees have been committed to the well-being of the community we serve and live in. It's the best energy we can provide.



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SELECTED FINANCIAL DATA

	2000	1999	1998	1997	1996
	(Dollar amounts in millions, except per share amounts)				
Summary of Operations					
Total Revenues	**$ 3,878.5**	$3,786.2	$3,386.4	$3,307.6	$3,153.2
Total Expenses	**3,038.3**	3,026.3	2,647.9	2,584.0	2,483.7
Income From Operations	**840.2**	759.9	738.5	723.6	669.5
Other Income (Expense)	**6.6**	7.9	5.7	(52.8)	6.1
Income Before Fixed Charges and Income Taxes	**846.8**	767.8	744.2	670.8	675.6
Fixed Charges	**271.4**	255.0	260.6	258.7	237.0
Income Before Income Taxes	**575.4**	512.8	483.6	412.1	438.6
Income Taxes	**230.1**	186.4	177.7	158.0	166.3
Income Before Extraordinary Item	**345.3**	326.4	305.9	254.1	272.3
Extraordinary Loss, Net of Income Taxes	**—**	(66.3)	—	—	—
Net Income	**$ 345.3**	$ 260.1	$ 305.9	$ 254.1	$ 272.3
Earnings Per Share of Common Stock and Earnings Per Share of Common Stock—Assuming Dilution Before Extraordinary Item	**$2.30**	$2.18	$2.06	$1.72	$1.85
Extraordinary Loss, Net of Income Taxes	**—**	(.44)	—	—	—
Earnings Per Share of Common Stock and Earnings Per Share of Common Stock—Assuming Dilution	**$2.30**	$1.74	$2.06	$1.72	$1.85
Dividends Declared Per Share of Common Stock	**$1.68**	$1.68	$1.67	$1.63	$1.59
Summary of Financial Condition					
Total Assets	**$12,384.6**	$9,683.8	$9,434.1	$8,900.0	$8,678.2
Capitalization					
Long-term debt	**$ 3,159.3**	$2,575.4	$3,128.1	$2,988.9	$2,758.8
Redeemable preference stock	**—**	—	—	90.0	134.5
Preference stock not subject to mandatory redemption	**190.0**	190.0	190.0	210.0	210.0
Common shareholders' equity	**3,153.0**	2,993.0	2,981.5	2,870.4	2,854.7
Total Capitalization	**$ 6,502.3**	$5,758.4	$6,299.6	$6,159.3	$5,958.0
Financial Statistics at Year End					
Ratio of Earnings to Fixed Charges	**2.78**	2.87	2.60	2.35	2.44
Book Value Per Share of Common Stock	**$20.95**	$20.01	$19.98	$19.44	$19.33
Number of Common Shareholders *(In Thousands)*	**60.1**	66.1	69.9	73.7	77.6

Certain prior-year amounts have been reclassified to conform with the current year's presentation.

	2000*	1999	1998	1997	1996
Electric Operating Statistics					
Revenues *(In Millions)*					
Residential	**$ 922.6**	$ 975.2	$ 948.6	$ 932.5	$ 958.7
Commercial	**926.2**	939.3	912.9	892.6	861.3
Industrial	**203.6**	204.3	211.5	211.9	207.6
System Sales	**2,052.4**	2,118.8	2,073.0	2,037.0	2,027.6
Interchange and Other Sales	**53.8**	112.1	120.8	132.7	155.9
Other	**29.0**	29.1	27.0	22.3	25.5
Total	**$2,135.2**	$2,260.0	$2,220.8	$2,192.0	$2,209.0
Sales *(In Thousands)*—MWH					
Residential	**11,675**	11,349	10,965	10,806	11,243
Commercial	**14,042**	13,565	13,219	12,718	12,591
Industrial	**4,476**	4,350	4,583	4,575	4,596
System Sales	**30,193**	29,264	28,767	28,099	28,430
Interchange and Other Sales	**2,064**	4,785	5,454	6,224	7,580
Total	**32,257**	34,049	34,221	34,323	36,010
Customers *(In Thousands)*					
Residential	**1,033.4**	1,021.4	1,009.1	1,001.0	995.2
Commercial	**108.9**	107.7	106.5	105.9	104.5
Industrial	**5.0**	4.7	4.6	4.5	4.3
Total	**1,147.3**	1,133.8	1,120.2	1,111.4	1,104.0
Average Use per Residential Customer—KWH	**11,297**	11,111	10,866	10,794	11,297
Average Rate per KWH *(System Sales)*—¢					
Residential	**7.90**	8.59	8.65	8.63	8.53
Commercial	**6.60**	6.92	6.91	7.02	6.84
Industrial	**4.55**	4.70	4.62	4.63	4.52
System Load Factor	**60.5%**	55.7%	57.4%	56.9%	57.5%
Gas Operating Statistics					
Revenues *(In Millions)*					
Residential —Excluding Delivery Service	**$ 328.4**	$ 298.1	$ 279.2	$ 321.7	$ 320.1
—Delivery Service	**23.5**	11.5	4.9	0.5	—
Commercial—Excluding Delivery Service	**97.9**	79.3	75.6	113.5	125.1
—Delivery Service	**25.8**	24.4	19.4	12.9	7.2
Industrial —Excluding Delivery Service	**10.9**	8.2	8.0	11.4	17.1
—Delivery Service	**16.3**	16.1	16.0	17.2	14.6
System Sales	**502.8**	437.6	403.1	477.2	484.1
Off-System Sales	**101.0**	42.9	40.9	37.5	26.6
Other	**7.8**	7.6	7.1	6.9	6.6
Total	**$ 611.6**	$ 488.1	$ 451.1	$ 521.6	$ 517.3
Sales *(In Thousands)*—DTH					
Residential —Excluding Delivery Service	**34,561**	34,272	33,595	39,958	43,784
—Delivery Service	**9,209**	4,468	1,890	205	—
Commercial—Excluding Delivery Service	**13,186**	11,733	11,775	18,435	22,698
—Delivery Service	**22,921**	20,288	16,633	12,964	8,755
Industrial —Excluding Delivery Service	**1,386**	1,367	1,412	2,016	2,887
—Delivery Service	**32,382**	33,118	34,798	38,791	36,201
System Sales	**113,645**	105,246	100,103	112,369	114,325
Off-System Sales	**22,456**	15,543	16,724	14,759	9,968
Total	**136,101**	120,789	116,827	127,128	124,293
Customers *(In Thousands)*					
Residential	**553.7**	543.5	532.5	524.5	516.5
Commercial	**40.1**	39.9	39.6	39.3	38.9
Industrial	**1.4**	1.3	1.3	1.3	1.3
Total	**595.2**	584.7	573.4	565.1	556.7
Average Use per Residential Customer (Excluding Delivery Service)—Therms	**624**	631	631	762	848
Average Rate per Therm—$					
Residential (Excluding Delivery Service)	**.95**	.87	.83	.81	.73
Commercial (Excluding Delivery Service)	**.74**	.68	.64	.62	.55
Industrial (Excluding Delivery Service)	**.79**	.60	.57	.57	.59
Peak Day Sendout *(In Thousands)*—DTH	**795.7**	727.8	658.4	765.0	709.0
Peak Day Capability *(In Thousands)*—DTH	**825.1**	836.6	833.0	870.0	870.0

Utility operating statistics do not reflect the elimination of intercompany transactions.

**Electric operating results reflect generation function as part of regulated operations through June 30, 2000.*

Introduction

On April 30, 1999, Constellation Energy® Group, Inc. (Constellation Energy) became the holding company for Baltimore Gas and Electric Company (BGE®) and Constellation® Enterprises, Inc. Constellation Enterprises was previously owned by BGE.

References in this report to "we" and "our" are to Constellation Energy and its subsidiaries, collectively. Reference in this report to the "utility business" is to BGE.

Constellation Energy's subsidiaries primarily include a domestic merchant energy business focused mostly on power marketing and merchant generation in North America, and BGE.

We realigned our organization in response to the deregulation of electric generation in Maryland. In the first quarter of 2000, we combined our wholesale power marketing operation with our domestic plant development and operation activities to form a domestic merchant energy business. At the same time, we revised our operating segments to reflect those realignments as presented in Note 2 on page 59.

On July 1, 2000, as a result of the deregulation of electric generation, BGE transferred its generating assets and related liabilities at book value to new nonregulated subsidiaries—Calvert Cliffs Nuclear Power Plant, Inc. and Constellation Power Source Generation, Inc. We discuss the deregulation of electric generation in the *Current Issues—Electric Competition* section on page 26.

Effective July 1, 2000, we formed a nonregulated holding company, Constellation Power Source Holdings, Inc., that includes:

- the wholesale power marketing and risk management activities of Constellation Power Source,™ Inc.,
- the domestic power projects of Constellation Investments,™ Inc. and Constellation Power,™ Inc., and subsidiaries, and
- the generating assets of Constellation Power Source Generation, Inc.

As a result of these changes, our domestic merchant energy business includes the operations of Constellation Power Source Holdings, the nuclear generation of Calvert Cliffs Nuclear Power Plant, Inc., and the nuclear consulting services of Constellation Nuclear, ™ LLC.

Also, effective July 1, 2000, the financial results of the electric generation portion of our business are included in the domestic merchant energy business. Prior to that date, the financial results of electric generation were included in BGE's regulated electric business.

BGE remains a regulated electric and gas public utility distribution company with a service territory in the City of Baltimore and all or part of ten counties in Central Maryland.

Our other nonregulated businesses include the:

- Latin American power projects of Constellation Power, and subsidiaries,
- energy products and services of Constellation Energy Source,™ Inc.,
- home products, commercial building systems, and residential and commercial electric and gas retail marketing of BGE Home Products & Services,™ Inc. and subsidiaries,
- general partnership, in which BGE is a partner, of District Chilled Water General Partnership (ComfortLink®) that provides cooling services for commercial customers in Baltimore,
- financial investments of Constellation Investments, and
- real estate holdings and senior-living facilities of Constellation Real Estate Group,™ Inc.

As discussed further in the *Strategy* section on page 25, on October 23, 2000, we announced initiatives to separate our domestic merchant energy business from our remaining businesses. These remaining businesses include BGE and the other nonregulated businesses described above.

In this discussion and analysis, we explain the general financial condition and the results of operations for Constellation Energy including:

- what factors affect our businesses,
- what our earnings and costs were in 2000 and 1999,
- why our earnings and costs changed from the year before,
- where our earnings come from,
- how all of this affects our overall financial condition,
- what our expenditures for capital projects were for 1998 through 2000, and what we expect them to be through 2003, and
- where we expect to get cash for future capital expenditures.

As you read this discussion and analysis, refer to our Consolidated Statements of Income on page 45, which present the results of our operations for 2000, 1999, and 1998. We analyze and explain the differences between periods by operating segment. Our analysis is important in making decisions about your investments in Constellation Energy.

Also, this discussion and analysis is based on the operation of the electric generation portion of our utility business under rate regulation through June 30, 2000. Our regulated electric business changed as we transferred our electric generation assets and related liabilities to our domestic merchant energy business and we entered into retail customer choice for electric generation effective July 1, 2000. In addition, we announced our intention to separate our domestic merchant energy business from our remaining businesses. Accordingly, the results of operations and financial condition described in this discussion and analysis are not necessarily indicative of future performance.

Strategy

Customer choice significantly impacts our business. In response to customer choice, we regularly evaluate our strategies with two goals in mind: to improve our competitive position, and to anticipate and adapt to regulatory change. Prior to July 1, 2000, the majority of our earnings were from BGE. Going forward, prior to separating into two companies, we expect to derive almost two-thirds of our earnings from our domestic merchant energy business.

While BGE continues to be regulated and to deliver electricity and natural gas through its core distribution business, our primary growth strategies center on the nonregulated domestic merchant energy business with the objective of providing new sources of earnings growth.

On October 23, 2000, we announced three initiatives to advance our growth strategies. The first initiative is that we entered into an agreement (the "Agreement") with an affiliate of The Goldman Sachs Group, Inc. ("Goldman Sachs"). Under the terms of the Agreement, Goldman Sachs will acquire up to a 17.5% equity interest in our domestic merchant energy business, which will be consolidated under a single holding company ("Holdco"). Goldman Sachs will also acquire a ten-year warrant for up to 13% of Holdco's common stock (subject to certain adjustments). The warrant is exercisable six months after Holdco's common stock becomes publicly available. The amount of common stock which Goldman Sachs may receive upon exercise will be equal to the excess of the market price of Holdco's common stock at the time of exercise over the exercise price of $60 per share for all the stock subject to the warrant, divided by the market price. Holdco may at its option pay Goldman Sachs such excess in cash. Goldman Sachs is acquiring its interest and the warrant in exchange for $250 million in cash (subject to adjustment in certain instances) and certain assets related to our power marketing operation. At closing, Goldman Sachs' existing services agreement with our power marketing operation will terminate.

The second initiative is a plan to separate our domestic merchant energy business from our remaining businesses as discussed in the introduction. The separation will create two stand-alone, publicly traded energy companies. One will be a merchant energy business engaged in wholesale power marketing and generation under the name "Constellation Energy Group" after the separation. The other will be a regional retail energy delivery and energy services company, BGE Corp., which will include BGE, our other nonregulated businesses, and our investment in Orion Power Holdings, Inc. ("Orion").

As a result of the separation, shareholders will continue to own all of Constellation Energy's current businesses through their ownership of the new Constellation Energy Group and BGE Corp.

The third initiative is a change in our common stock dividend policy effective April 2001. In a move closely aligned with our separation plan, effective April 2001, our annual dividend is expected to be set at $.48 per share. After the separation, BGE Corp. expects to pay initial annual dividends of $.48 per share. Constellation Energy Group, as a growing merchant energy company, initially expects to reinvest its earnings in order to fund its growth plans and not to pay a dividend.

The closing of the transaction with Goldman Sachs and the separation are subject to customary closing conditions and contingent upon obtaining regulatory approvals and a Private Letter Ruling from the Internal Revenue Service regarding certain tax matters. The transaction and separation are expected to be completed by mid to late 2001.

We discuss these strategic initiatives further in our Report on Form 8-K and exhibits filed with the Securities and Exchange Commission (SEC) on October 23, 2000.

Currently, our domestic merchant energy business controls over 9,000 megawatts of generation. In December 2000, we announced that a subsidiary of Constellation Nuclear will purchase 1,550 megawatts of the 1,757 megawatts total generating capacity of the Nine Mile Point nuclear power plant located in Scriba, New York. The total purchase price, including fuel, is $815 million. We discuss the planned acquisition of the Nine Mile Point power plant in more detail in Note 10 on page 70.

We also plan to construct generating facilities representing 1,100 megawatts of natural gas-fired peaking capacity in the Mid-Atlantic and Mid-West regions by the summer of 2001. An additional 6,700 megawatts of natural gas-fired peaking and combined cycle production facilities in the Mid-West and South regions are scheduled for completion in 2002 and beyond. By 2005, our domestic merchant energy business expects to control approximately 30,000 megawatts through the construction or purchase of additional nuclear and non-nuclear generation assets and contractual arrangements.

We decided to exit the Latin American portion of our operation as a result of our concentration on domestic merchant energy. Currently, we are actively seeking a buyer for the Latin American portion of our business and are working toward completing our exit strategy in 2001.

We also might consider one or more of the following strategies:

- the complete or partial separation of our transmission and distribution functions,
- mergers or acquisitions of utility or non-utility businesses, and
- sale of generation assets or one or more businesses.

Current Issues

With the shift toward customer choice, competition, and the growth of our domestic merchant energy business, various factors will affect our financial results in the future. These factors include, but are not limited to, operating our generation assets in a deregulated market without the benefit of a fuel rate adjustment clause, the timing and implications of deregulation in other regions where our domestic merchant energy business will operate, the loss of revenues due to customers choosing alternative suppliers, higher volatility of earnings and cash flows, and increased financial requirements of our domestic merchant energy business. Please refer to the *Forward Looking Statements* section on page 43 for additional factors.

In this section, we discuss in more detail several issues that affect our businesses.

Electric Competition

We are facing electric competition on various fronts, including:

- the construction of generating units to meet increased demand for electricity,
- the sale of electricity in wholesale power markets,
- competing with alternative energy suppliers, and
- electric sales to retail customers.

Maryland

On April 8, 1999, Maryland enacted the Electric Customer Choice and Competition Act of 1999 (the "Act") and accompanying tax legislation that significantly restructured Maryland's electric utility industry and modified the industry's tax structure.

In the Restructuring Order discussed below, the Maryland Public Service Commission (Maryland PSC) addressed the major provisions of the Act. The accompanying tax legislation is discussed in detail in Note 4 on page 62.

On November 10, 1999, the Maryland PSC issued a Restructuring Order that resolved the major issues surrounding electric restructuring, accelerated the timetable for customer choice, and addressed the major provisions of the Act. The Restructuring Order also resolved the electric restructuring proceeding (transition costs, customer price protections, and unbundled rates for electric services) and a petition filed in September 1998 by the Office of People's Counsel (OPC) to lower our electric base rates. The major provisions of the Restructuring Order are discussed in Note 4 on page 62.

We believe that the Restructuring Order provided sufficient details of the transition plan to competition for BGE's electric generation business to require BGE to discontinue the application of Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation* for that portion of its business. Accordingly, in the fourth quarter of 1999, we adopted the provisions of SFAS No. 101, *Regulated Enterprises—Accounting for the Discontinuation of FASB Statement No. 71* and Emerging Issues Task Force Consensus (EITF) No. 97-4, *Deregulation of the Pricing of Electricity—Issues Related to the Application of FASB Statements No. 71 and 101* for BGE's electric generation business. BGE's transmission and distribution business continues to meet the requirements of SFAS No. 71 as that business remains regulated. We describe the effect of applying these accounting requirements in Note 4 on page 63.

Please refer to Note 10 on page 73 for a discussion regarding appeals of the Restructuring Order.

As a result of the deregulation of electric generation, the following occurred effective July 1, 2000:

- All customers, except a few commercial and industrial companies that have signed contracts with BGE, can choose their electric energy supplier. BGE will provide a standard offer service for customers that do not select an alternative supplier. In either case, BGE will continue to deliver electricity to all customers in areas traditionally served by BGE.
- BGE reduced residential base rates by approximately 6.5%, on average about $54 million a year. These rates will not change before July 2006.
- BGE transferred, at book value, its nuclear generating assets, its nuclear decommissioning trust fund, and related liabilities to Calvert Cliffs Nuclear Power Plant, Inc. In addition, BGE transferred, at book value, its fossil generating assets and related liabilities and its partial ownership interest in two coal plants and a hydroelectric plant located in Pennsylvania to Constellation Power Source Generation. In total, these generating assets represent about 6,240 megawatts of generation capacity with a total net book value at June 30, 2000 of approximately $2.4 billion.
- BGE assigned approximately $47 million to Calvert Cliffs Nuclear Power Plant, Inc. and $231 million to Constellation Power Source Generation of tax-exempt debt related to the transferred assets. Also, Constellation Power Source Generation issued approximately $366 million in unsecured promissory notes to BGE. Repayments of the notes by Constellation Power Source Generation will be used exclusively to service the current maturities of certain BGE long-term debt.
- BGE transferred equity associated with the generating assets to Calvert Cliffs Nuclear Power Plant, Inc. and Constellation Power Source Generation.
- The fossil fuel and nuclear fuel inventories, materials and supplies, and certain purchased power contracts of BGE were also assumed by these subsidiaries.

Effective July 1, 2000, BGE provides standard offer service to customers at fixed rates over various time periods during the transition period for those customers that do not choose an alternate supplier. In addition, the electric fuel rate was discontinued effective July 1, 2000. Constellation Power Source provides BGE with the energy and capacity required to meet its standard offer service obligations for the first three years of the transition period. Thereafter, BGE will competitively bid the energy and capacity.

Constellation Power Source obtains the energy and capacity to supply BGE's standard offer service obligations from affiliates that own Calvert Cliffs Nuclear Power Plant (Calvert Cliffs) and BGE's former fossil plants, supplemented with energy and capacity purchased from the wholesale market as necessary.

Other States

Our domestic merchant energy business is focused on expanding its business through marketing energy products to wholesale customers and acquiring control of additional generating facilities. This business will focus on states with strong growth in energy demand and that provide opportunities through ongoing deregulation and the creation of competitive markets. Delays in, or the ultimate form of, deregulation of electric generation in various states may affect our domestic merchant energy business strategy.

Our domestic merchant energy business has $297.9 million invested in power projects that sell 142 megawatts of electricity in California under power purchase agreements as discussed in the *California Power Purchase Agreements* section on page 32. The counterparties to the agreements are two California investor-owned utilities that recently were downgraded by rating agencies to below investment grade. Due to various factors, including extreme weather and shortage of generation, these utilities are paying more for power than they can recover from their customers under the deregulation plan in California. The governor and legislature of California have undertaken emergency actions to provide financial support that could help stabilize the financial condition of the two utilities.

At December 31, 2000, credit exposure under these agreements was not material to our financial results. However, if the ultimate resolution of the events in California prevents collection of unpaid balances under power purchase agreements on some or all of our projects, a material impact could result. Additionally, if the events in California result in a modification or termination of these agreements that reduces future cash flows, we would have to evaluate whether our investments in the power projects that are parties to the agreements are impaired. An impairment of these investments could have a material impact on our financial results. Our domestic merchant energy business does not have any other direct agreements with these utilities. However, we may be impacted if one or more of our other counterparties is significantly affected by the events in California, or by the operation of the California Power Exchange.

Gas Competition

Currently, no regulation exists for the wholesale price of natural gas as a commodity, and the regulation of interstate transmission at the federal level has been reduced. All BGE gas customers have the option to purchase gas from other suppliers.

Regulation by the Maryland PSC

In addition to electric restructuring which was discussed earlier, regulation by the Maryland PSC influences BGE's businesses.

Under traditional rate regulation that continues after July 1, 2000 for BGE's electric transmission and distribution, and gas businesses, the Maryland PSC determines the rates we can charge our customers. Prior to July 1, 2000, BGE's regulated electric rates consisted primarily of a "base rate" and a "fuel rate." Effective July 1, 2000, BGE discontinued its electric fuel rate and unbundled its rates to show separate components for delivery service, competitive transition charges, standard offer services (generation), transmission, universal service, and taxes. The rates for BGE's regulated gas business continue to consist of a "base rate" and a "fuel rate."

Base Rate

The base rate is the rate the Maryland PSC allows BGE to charge its customers for the cost of providing them service, plus a profit. BGE has both an electric base rate and a gas base rate. Higher electric base rates apply during the summer when the demand for electricity is higher. Gas base rates are not affected by seasonal changes.

BGE may ask the Maryland PSC to increase base rates from time to time. The Maryland PSC historically has allowed BGE to increase base rates to recover increased utility fixed asset costs, plus a profit, beginning at the time of replacement. Generally, rate increases improve our utility earnings because they allow us to collect more revenue. However, rate increases are normally granted based on historical data and those increases may not always keep pace with increasing costs. Other parties may petition the Maryland PSC to decrease base rates.

On November 17, 1999, BGE filed an application with the Maryland PSC to increase its gas base rates. On June 19, 2000, the Maryland PSC authorized a $6.4 million annual increase in our gas base rates effective June 22, 2000. As a result of the Restructuring Order, BGE's residential electric base rates are frozen until 2006.

Electric delivery service rates are frozen for a four-year period for commercial and industrial customers. The generation and transmission components of rates are frozen for different time periods depending on the service options selected by those customers.

Fuel Rate

Through June 30, 2000, we charged our electric customers separately for the fuel we used to generate electricity (nuclear fuel, coal, gas, or oil) and for the net cost of purchases and sales of electricity. We charged the actual cost of these items to the customer with no profit to us. If these fuel costs went up, the Maryland PSC permitted us to increase the fuel rate.

Under the Restructuring Order, BGE's electric fuel rate was frozen until July 1, 2000, at which time the fuel rate clause was discontinued. We deferred the difference between our actual costs of fuel and energy and what we collected from customers under the fuel rate through June 30, 2000.

In September 2000, the Maryland PSC approved the collection of the $54.6 million accumulated difference between our actual costs of fuel and energy and the amounts collected from customers that were deferred under the electric fuel rate clause through June 30, 2000. We are collecting this accumulated difference from customers over the twelve-month period beginning October 2000. Effective July 1, 2000, our earnings are affected by the changes in the cost of fuel and energy.

We charge our gas customers separately for the natural gas they purchase from us. The price we charge for the natural gas is based on a market based rates incentive mechanism approved by the Maryland PSC. We discuss market based rates in more detail in the *Gas Cost Adjustments* section on page 36 and in Note 1 on page 54.

FERC Regulation—Regional Transmission Organizations

In December 1999, the Federal Energy Regulatory Commission (FERC) issued Order 2000, amending its regulations under the Federal Power Act to advance the formation of Regional Transmission Organizations (RTOs). The regulations require that each public utility that owns, operates, or controls facilities for the transmission of electric energy in interstate commerce make certain filings with respect to forming and participating in a RTO. FERC also identified the minimum characteristics and functions that a transmission entity must satisfy in order to be considered a RTO.

According to the Order, a public utility that is a member of an existing transmission entity that has been approved by FERC as in conformance with the Independent System Operator (ISO) principles set forth in the FERC Order No. 888, such as BGE, through its membership in PJM (Pennsylvania-New Jersey-Maryland) Interconnection, was required to make a filing no later than January 15, 2001. PJM and the joint transmission owners, including BGE, made the filing on October 11, 2000. That filing explained the extent to which PJM met the minimum characteristics and functions of a RTO and explained its plans to conform to these characteristics and functions.

As a member of PJM, an existing ISO, BGE does not expect to be materially impacted by the Order. However, we are appealing two requirements of the Order whereby:

- we would have to go through PJM to make a filing with FERC to change our transmission rates, and
- we would have to transfer operational control of our transmission facilities to PJM (or any other RTO we may wish to join).

Weather

Domestic Merchant Energy Business

Weather conditions in the different regions of North America influence the financial results of our domestic merchant energy business. Typically, demand for electricity and its price are higher in the summer and the winter, when weather is more extreme. However, all regions of North America typically do not experience extreme weather conditions at the same time. Since the majority of our generating plants currently are located in PJM, our financial results are affected, to a greater extent, by weather conditions in this area. However, by 2005, we expect to control approximately 30,000 megawatts of generation throughout various regions of North America.

Current weather conditions also can affect the forward market price of energy commodity and derivative contracts used by our power marketing operation that are accounted for on a mark-to-market basis. To the extent that our power marketing operation purchases and sells such contracts, our financial results could be influenced by the impact that weather conditions have on the market price of such contracts.

BGE

Weather affects the demand for electricity and gas for our regulated businesses. Very hot summers and very cold winters increase demand. Mild weather reduces demand. Residential sales for our regulated businesses are impacted more by weather than commercial and industrial sales, which are mostly affected by business needs for electricity and gas.

However, the Maryland PSC allows us to record a monthly adjustment to our regulated gas business revenues to eliminate the effect of abnormal weather patterns. We discuss this further in the *Weather Normalization* section on page 36.

We measure the weather's effect using "degree days." A degree day is the difference between the average daily actual temperature and a baseline temperature of 65 degrees. Cooling degree days result when the average daily actual temperature exceeds the 65 degree baseline. Heating degree days result when the average daily actual temperature is less than the baseline.

During the cooling season, hotter weather is measured by more cooling degree days and results in greater demand for electricity to operate cooling systems. During the heating season, colder weather is measured by more heating degree days and results in greater demand for electricity and gas to operate heating systems.

We show the number of cooling and heating degree days in 2000 and 1999, the percentage change in the number of degree days from the prior year, and the number of degree days in a "normal" year as represented by the 30-year average in the following table.

	2000	1999	30-year Average
Cooling degree days	**736**	845	840
Percentage change from prior year	**(12.9)%**	(7.7)%	
Heating degree days	**4,936**	4,585	4,771
Percentage change from prior year	**7.7%**	11.3%	

Other Factors

Other factors, aside from weather, impact the demand for electricity and gas in our regulated businesses. These factors include the "number of customers" and "usage per customer" during a given period. We use these terms later in our discussions of regulated electric and gas operations. In those sections, we discuss how these and other factors affected electric and gas sales during the periods presented.

The number of customers in a given period is affected by new home and apartment construction and by the number of businesses in our service territory. Under the Restructuring Order, BGE's electric customers can become delivery service customers only and can purchase their electricity from other sources. We will collect a delivery service charge to recover the fixed costs for the service we provide. The remaining electric customers will receive standard offer service from BGE at the fixed rates provided by the Restructuring Order. Usage per customer refers to all other items impacting customer sales that cannot be measured separately. These factors include the strength of the economy in our service territory. When the economy is healthy and expanding, customers tend to consume more electricity and gas. Conversely, during an economic downtrend, our customers tend to consume less electricity and gas.

Environmental and Legal Matters

You will find details of our environmental and legal matters in Note 10 on page 71 and in our most recent Annual Report on Form 10-K. Some of the information is about costs that may be material to our financial results.

Accounting Standards Issued

We discuss recently issued accounting standards in Note 1 on page 59.

Results of Operations

In this section, we discuss our earnings and the factors affecting them. We begin with a general overview, then separately discuss earnings for our operating segments. Changes in fixed charges and income taxes are discussed in the aggregate for all segments in the *Consolidated Nonoperating Income and Expenses* section on page 38.

Overview

Total Earnings Per Share of Common Stock

	2000*	1999	1998
Earnings before nonrecurring charges included in operations:			
Domestic merchant energy	**$1.48**	$ .44	$ .36
Regulated electric	**.71**	1.81	1.75
Regulated gas	**.20**	.22	.18
Other nonregulated	**.04**	.01	(.09)
Total earnings per share before nonrecurring charges included in operations:	**2.43**	2.48	2.20
Nonrecurring charges included in operations (see Note 2 on page 60):			
Deregulation transition cost	**(.10)**	—	—
TVSERP	**(.03)**	—	—
Hurricane Floyd	—	(.03)	—
Write-downs of power projects	—	(.12)	—
Write-off of energy services investment	—	—	(.04)
Write-down of financial investment	—	(.11)	—
Write-down of real estate and senior-living investments	—	(.04)	(.10)
Total earnings per share before extraordinary item	**2.30**	2.18	2.06
Extraordinary loss (see Note 4 on page 63)	—	(.44)	—
Total earnings per share	**$2.30**	$1.74	$2.06

**Earnings for the years presented reflect a significant shift from the regulated electric business to the domestic merchant energy business as a result of the transfer of BGE's electric generation assets to nonregulated subsidiaries on July 1, 2000 in accordance with the Restructuring Order. We discuss the Restructuring Order in more detail in Note 4 on page 62.*

2000

Our 2000 total earnings increased $85.2 million, or $.56 per share, compared to 1999 mostly because we recorded an extraordinary charge of $66.3 million, or $.44 per share, associated with the deregulation of the electric generation portion of our business in 1999. In addition, we recorded several nonrecurring charges in 1999 that had a negative impact in that year as discussed below. In 2000, we recorded the following nonrecurring charges in operations:

- $15.0 million after-tax, or $.10 per share, deregulation transition cost in June 2000 to a third party incurred by our power marketing operation to provide BGE's standard offer service requirements, and
- $4.2 million after-tax, or $.03 per share, expense during the first and second quarters of 2000 for BGE employees that elected to participate in a Targeted Voluntary Special Early Retirement Program (TVSERP).

Earnings before nonrecurring charges included in operations decreased $7.3 million, or $.05 per share, mostly because we recognized $29.9 million, or $18.1 million after-tax, of the 6.5% annual residential rate reduction that was effective July 1, 2000 and we had higher interest costs in 2000 compared to 1999. We also recognized $5.7 million after-tax, or $.04 per share, for contributions to the universal service fund relating to the deregulation of electric generation. These decreases were offset partially by higher earnings in our domestic merchant energy and our other nonregulated businesses.

In 2000, earnings from our domestic merchant energy business before nonrecurring charges increased compared to 1999 because of higher earnings in both our power marketing and domestic generation operations.

In 2000, earnings from our other nonregulated businesses increased mostly because of higher earnings in our financial investments operation.

1999

Our 1999 total earnings decreased $45.8 million, or $.32 per share, compared to 1998. Our total earnings decreased mostly because we recorded an extraordinary charge associated with the deregulation of the electric generation portion of our business. We discuss the extraordinary charge in Note 4 on page 63. Our 1999 total earnings also include the following nonrecurring items included in our operations:

- Our regulated electric business recorded $4.9 million after-tax, or $.03 per share, of expenses related to Hurricane Floyd.
- Our domestic generation operation recorded write-downs of certain power projects for $14.2 million after-tax, or $.09 per share, and our Latin American operation recorded a $4.5 million after-tax, or $.03 per share, write-down of a power project.
- Our financial investments operation recorded a $16.0 million after-tax, or $.11 per share, write-down of a financial investment.
- Our real estate and senior-living facilities operation recorded a $5.8 million after-tax, or $.04 per share, write-down of certain senior-living facilities.

These decreases were offset partially by higher earnings from regulated utility, domestic merchant energy, and other nonregulated business operations excluding nonrecurring charges.

In 1999, regulated utility earnings before the extraordinary charge increased compared to 1998 mostly because we had higher electricity and gas system sales that year, and we settled a capacity contract with PECO Energy Company in 1998 that had a negative impact on earnings in that year. This increase was offset partially by higher depreciation and amortization expense mostly due to the $75.0 million amortization of the regulatory asset recorded in 1999 for the reduction of our generation plant under the Restructuring Order, which reduced 1999 earnings by $48.8 million.

In 1999, earnings from our domestic merchant energy business before nonrecurring charges increased compared to 1998 mostly because of higher earnings from our power marketing operation.

In 1999, earnings from our other nonregulated businesses before nonrecurring charges increased compared to 1998 mostly because of higher earnings from our Latin American and real estate and senior-living facilities operations.

In the following sections, we discuss our earnings by business segment in greater detail.

Domestic Merchant Energy Business

Our domestic merchant energy business engages primarily in power marketing and domestic power generation. As discussed in the *Current Issues—Electric Competition* section on page 26, our domestic merchant energy business was significantly impacted by the July 1, 2000 implementation of customer choice in Maryland. At that time, BGE's generating assets became part of our nonregulated domestic merchant energy business, and Constellation Power Source began selling to BGE the energy and capacity required to meet its standard offer service obligations for the first three years of the transition period.

Constellation Power Source obtains the energy and capacity to supply BGE's standard offer service obligations from affiliates that own Calvert Cliffs and BGE's former fossil plants, supplemented with energy and capacity purchased from the wholesale market as necessary. Constellation Power Source also manages our wholesale market price risk.

In addition, effective July 1, 2000, domestic merchant energy business revenues include 90% of the competitive transition charges BGE collects from its customers (CTC revenues) and the portion of BGE's revenues providing for nuclear decommissioning costs.

Our earnings are exposed to various market risks as discussed in the *Market Risk* section on page 41. For example, our earnings are exposed to the risks of the competitive wholesale electricity market to the extent that our domestic merchant energy business has to purchase energy and/or capacity to meet obligations to supply power or meet other energy-related contractual arrangements at prices which may approach or exceed the applicable fixed sales price obligations. If the price of obtaining energy in the wholesale market exceeds the fixed sales price, our earnings would be adversely affected. We also are affected by operational risk, that is, the risk that a generating plant will not be available to produce energy when the energy is required. Imbalances in demand and supply can occur not only because of plant outages, but also because of transmission constraints, or extreme temperatures (hot or cold) causing demand to exceed available supply.

We cannot estimate the impact of the increased financial risks associated with the competitive wholesale electricity market. However, these financial risks could have a material impact on our financial results.

Earnings

	2000	1999	1998
	(In millions, except per share amounts)		
Revenues	**$992.0**	$212.9	$147.3
Operating expenses	**534.3**	111.1	47.8
Depreciation and amortization	**80.9**	5.0	3.0
Taxes other than income taxes	**24.1**	—	—
Income from operations	**$352.7**	$ 96.8	$ 96.5
Net income	**$206.8**	$ 52.4	$ 53.1
Total earnings per share before nonrecurring charges included in operations:	**$1.48**	$.44	$.36
Deregulation transition cost	**(.10)**	—	—
Write-down of power projects	**—**	(.09)	—
Earnings per share	**$1.38**	$.35	$.36

Above amounts include intercompany transactions eliminated in our Consolidated Financial Statements. Note 2 on page 60 provides a reconciliation of operating results by segment to our Consolidated Financial Statements.

Revenues

Our 2000 domestic merchant energy revenues increased $779.1 million compared to 1999 mostly because of:

- a $581.0 million increase related to providing BGE the energy and capacity required to meet its standard offer service obligation effective July 1, 2000,
- a $110.0 million increase related to CTC and decommissioning revenues included in the domestic merchant energy business effective July 1, 2000, and
- higher revenues from our power marketing and domestic generation operations.

Our 1999 domestic merchant energy revenues increased $65.6 million compared to 1998 mostly because of higher revenues from our power marketing operation offset partially by lower revenues from our domestic generation operation.

We discuss the revenues for our power marketing and domestic generation operations in the sections below.

Power Marketing

Power marketing revenues increased during 2000 compared to 1999 mostly because of higher transaction volumes in the Mid-Atlantic, Texas, and West regions, offset partially by lower margins.

Power marketing revenues increased during 1999 compared to 1998 mostly because of higher transaction margins and volumes.

Constellation Power Source uses the mark-to-market method of accounting. We discuss the mark-to-market method of accounting and Constellation Power Source's activities in more detail in Note 1 on page 54. As a result of the nature of its operations and the use of mark-to-market accounting, Constellation Power Source's revenues and earnings will fluctuate. We cannot predict these fluctuations, but the effect on our revenues and earnings could be material. The primary factors that cause these fluctuations are:

- the number and size of new transactions,
- the magnitude and volatility of changes in commodity prices and interest rates, and
- the number and size of open commodity and derivative positions Constellation Power Source holds or sells.

Constellation Power Source's management uses its best estimates to determine the fair value of commodity and derivative positions it holds and sells. These estimates consider various factors including closing exchange and over-the-counter price quotations, time value, volatility factors, and credit exposure. However, it is possible that future market prices could vary from those used in recording assets and liabilities from power marketing and trading activities, and such variations could be material. Assets and liabilities from energy trading activities (as shown in our *Consolidated Balance Sheets* beginning on page 46) increased significantly at December 31, 2000 compared to December 31, 1999 because of business growth during the period and increased market prices at the end of 2000.

Domestic Generation

Our domestic generation revenues increased during 2000 compared to 1999 mostly because of three factors:

- Our domestic generation operation recognized $13.3 million on the termination of an operating arrangement and the sale of certain subsidiaries. In April 2000, Constellation Operating Services, Inc. (COSI), a subsidiary of Constellation Power, Inc., ended its exclusive arrangement with Orion to operate Orion's facilities. Orion purchased from COSI the four subsidiary companies formed to operate power plants owned by Orion.
- In November 2000, our domestic generation operation recorded a $19.2 million gain on the sale of approximately 3.2 million shares of Orion stock.
- In 1999, our domestic generation operation recorded a write-off of two geothermal power projects as discussed below, which had a negative impact in that year.

In 1999, our domestic generation revenues decreased compared to 1998 mostly because of three factors:

- Our domestic generation operation wrote-off two geothermal power projects that totaled $21.4 million. These write-offs occurred because the expected future cash flows from the projects were less than the investment in the projects. For the first project, this resulted from the inability to restructure certain project agreements. For the second project, the water temperature of the geothermal resource used by one of the plants for production declined.
- In 1998, our domestic generation operation recorded a $17.2 million gain for its share of earnings in a partnership. The partnership recognized a gain on the sale of its ownership interest in a power purchase agreement.
- Revenues from our California power purchase agreements decreased as discussed below.

California Power Purchase Agreements

Our domestic generation operation has $297.9 million invested in 14 projects that sell electricity in California under power purchase agreements called "Interim Standard Offer No. 4" agreements.

Under these agreements, the electricity rates changed from fixed rates to variable rates beginning in 1996. In 2000, the last four projects transitioned to variable rates. In 1999 and prior years, the projects that transitioned to variable rates had lower revenues under variable rates than they did under fixed rates. In 2000, the prices received under these agreements were higher due to increases in the variable-rate pricing terms. However, due to the uncertainties in California, the recent increases in prices may not be indicative of future prices. We discuss the developments in California in the *Current Issues—Electric Competition* section on page 27.

We also describe these projects and the transition process in Note 3 on page 61 and Note 10 on page 74.

Operating Expenses

During 2000, domestic merchant energy operating expenses increased $423.2 million compared to 1999 mostly because of three factors:

- An increase of $191.6 million in fuel costs and $157.2 million in operations and maintenance costs. These costs were associated with the generation plants that were transferred from BGE effective July 1, 2000.
- A $24.0 million deregulation transition cost in June 2000 to a third party incurred by our power marketing operation to provide BGE's standard offer service requirements.
- An increase in power marketing operating expenses due to the growth of the operation.

During 1999, domestic merchant energy operating expenses increased $63.3 million compared to 1998 mostly because of the growth in our power marketing operation.

Depreciation and Amortization Expense

In 2000, domestic merchant energy depreciation and amortization expense increased $75.9 million compared to 1999 mostly because of $73.8 million of expenses associated with the generation plants that were transferred from BGE effective July 1, 2000.

In 1999, domestic merchant energy depreciation and amortization expense was about the same compared to 1998.

Taxes Other than Income Taxes

In 2000, domestic merchant energy taxes other than income taxes increased $24.1 million compared to 1999 because of $23.8 million of taxes other than income taxes associated with the generation plants that were transferred from BGE effective July 1, 2000.

In 1999, domestic merchant energy taxes other than income taxes were the same compared to 1998.

Regulated Electric Business

As previously discussed, our regulated electric business was significantly impacted by the July 1, 2000 implementation of customer choice. These changes include BGE's generating assets and related liabilities becoming part of our nonregulated domestic merchant energy business on that date.

Earnings

	2000	1999	1998
	(In millions, except per share amounts)		
Electric revenues	**$2,135.2**	$2,260.0	$2,220.8
Electric fuel and purchased energy	**870.7**	487.7	516.7
Operations and maintenance	**454.2**	629.6	630.5
Depreciation and amortization	**319.9**	376.4	313.0
Taxes other than income taxes	**157.8**	188.9	182.3
Income from operations	**$ 332.6**	$ 577.4	$ 578.3
Net income	**$ 102.3**	$ 198.8	$ 259.6
Total earnings per share before nonrecurring charges included in operations:	**$ .71**	$1.81	$1.75
TVSERP	**(.03)**	—	—
Hurricane Floyd	—	(.03)	—
Extraordinary loss	—	(.44)	—
Earnings per share	**$ .68**	$1.34	$1.75

Above amounts include intercompany transactions eliminated in our Consolidated Financial Statements. Note 2 on page 60 provides a reconciliation of operating results by segment to our Consolidated Financial Statements.

Electric Revenues

The changes in electric revenues in 2000 and 1999 compared to the respective prior year were caused by:

	2000	1999
	(In millions)	
Electric system sales volumes	**$ 40.9**	$ 41.3
Rates	**(119.9)**	4.5
Fuel rate surcharge	**12.6**	—
Total change in electric revenues from electric system sales	**(66.4)**	45.8
Interchange and other sales	**(58.3)**	(8.7)
Other	**(0.1)**	2.1
Total change in electric revenues	**$(124.8)**	$ 39.2

Electric System Sales Volumes

"Electric system sales volumes" are sales to customers in our service territory at rates set by the Maryland PSC. These sales do not include interchange sales and sales to others.

The percentage changes in our electric system sales volumes, by type of customer, in 2000 and 1999 compared to the respective prior year were:

	2000	1999
Residential	**2.9%**	3.5%
Commercial	**3.5**	2.6
Industrial	**2.9**	(5.1)

In 2000, we sold more electricity to residential customers compared to 1999 due to the colder winter weather, higher usage per customer, and an increased number of customers, offset partially by mild summer weather. We sold more electricity to commercial customers mostly due to higher usage per customer and an increased number of customers. We sold more electricity to industrial customers due to higher usage by Bethlehem Steel and an increased number of customers, offset partially by lower usage by other industrial customers. Usage was higher at Bethlehem Steel as a result of a 1999 shut down for a planned upgrade to their facilities that temporarily reduced their electricity consumption.

In 1999, we sold more electricity to residential customers due to higher usage per customer, colder winter weather, and an increased number of customers compared to 1998. This increase was offset partially by milder spring and early summer weather. We sold more electricity to commercial customers mostly due to higher usage per customer, an increased number of customers, and colder winter weather. We sold less electricity to industrial customers mostly because usage by Bethlehem Steel and other industrial customers decreased. This decrease was offset partially by an increase in the number of industrial customers.

Rates

Prior to July 1, 2000, our rates primarily consisted of an electric base rate and an electric fuel rate. Effective July 1, 2000, BGE discontinued its electric fuel rate and unbundled its rates to show separate components for delivery service, competitive transition charges, standard offer service (generation), transmission, universal service, and taxes. BGE's rates also were frozen in total except for the implementation of a residential base rate reduction totaling approximately $54 million annually. In addition, 90% of the CTC revenues BGE collects and the portion of its revenues providing for decommissioning costs, are included in revenues of the domestic merchant energy business effective July 1, 2000.

In 2000, rate revenues decreased compared to 1999 mostly because of the $29.9 million decrease caused by the 6.5% annual residential rate reduction, and the $110.0 million transfer of revenues to the domestic merchant energy business discussed above. This was offset partially by higher fuel rate revenues during the first half of 2000.

In 1999, rate revenues increased compared to 1998 because of higher fuel rate revenues. Fuel rate revenues increased mostly because we sold more electricity.

Fuel Rate Surcharge
In September 2000, the Maryland PSC approved the collection of the $54.6 million accumulated difference between our actual costs of fuel and energy and the amounts collected from customers that were deferred under the electric fuel rate clause through June 30, 2000. We discuss this further in the *Electric Fuel Rate Clause* section below.

Interchange and Other Sales
"Interchange and other sales" are sales in the PJM energy market and to others. PJM is an ISO that operates a regional power pool with members that include many wholesale market participants, as well as BGE, and other utility companies. Prior to the implementation of customer choice, BGE sold energy to PJM members and to others after it had satisfied the demand for electricity in its own system.

Effective July 1, 2000, BGE no longer engages in interchange sales. These activities are now included in our domestic merchant energy business which resulted in a decrease in interchange and other sales for the second half of 2000 compared to 1999. In addition, BGE had lower interchange and other sales during the first half of 2000 when increased demand for system sales reduced the amount of energy BGE had available for off-system sales.

In 1999, interchange and other sales revenues decreased compared to 1998 mostly because higher demand for system sales reduced the amount of energy BGE had available for off-system sales.

Electric Fuel and Purchased Energy Expenses

	2000	1999	1998
	(In millions)		
Actual costs	**$868.0**	$558.0	$525.7
Net recovery (deferral) of costs under electric fuel rate clause	**2.7**	(70.3)	(9.0)
Total electric fuel and purchased energy expense	**$870.7**	$487.7	$516.7

Actual Costs
In 2000, our actual costs of fuel and purchased energy were higher compared to 1999 mostly because of the deregulation of our electric generation. As discussed in the *Current Issues—Electric Competition* section on page 26, effective July 1, 2000, BGE transferred its generating assets to, and began purchasing substantially all of the energy and capacity required to provide electricity to standard offer service customers from, the domestic merchant energy business. In 2000, the cost of energy BGE purchased from our domestic merchant energy business was $581.0 million. The higher amount paid for purchased energy is offset by the absence of $191.6 million in fuel costs, and lower operations and maintenance, depreciation, taxes, and other costs at BGE as a result of no longer owning and operating the transferred electric generation plants.

Prior to July 1, 2000, BGE's purchased fuel and energy costs only included actual costs of fuel to generate electricity (nuclear fuel, coal, gas, or oil) and electricity we bought from others.

In 1999, our actual costs of fuel to generate electricity and electricity we bought from others were higher compared to 1998 mostly because the price of electricity we bought from others was higher. The price of electricity changes based on market conditions and contract terms. This increase was offset partially by our settlement of a capacity contract with PECO in 1998.

Electric Fuel Rate Clause
Prior to July 1, 2000, we deferred (included as an asset or liability on the Consolidated Balance Sheets and excluded from the Consolidated Statements of Income) the difference between our actual costs of fuel and energy and what we collected from customers under the fuel rate in a given period. Effective July 1, 2000, the fuel rate clause was discontinued under the terms of the Restructuring Order. In September 2000, the Maryland PSC approved the collection of the $54.6 million accumulated difference between our actual costs of fuel and energy and the amounts collected from customers that were deferred under the electric fuel rate clause through June 30, 2000. We are collecting this accumulated difference from customers over the twelve-month period beginning October 2000.

In 2000, the net deferral of costs under the electric fuel rate clause decreased compared to 1999 due to the discontinuation of the fuel rate clause effective July 1, 2000.

In 1999, the net deferral of costs under the electric fuel rate clause increased compared to 1998 because the 1999 deferral reflected higher purchased power costs, especially during record-setting summer peak loads.

Electric Operations and Maintenance Expenses
In 2000, regulated electric operations and maintenance expenses decreased $175.4 million compared to 1999 mostly because effective July 1, 2000, $157.2 million of costs were no longer incurred by this business segment. These costs were associated with the electric generation assets that were transferred to the domestic merchant energy business. In addition, 1999 operations and maintenance expenses included costs for system restoration activities related to Hurricane Floyd and a major winter ice storm, and costs associated with the preparation for the year 2000 (Y2K). These costs had a negative impact in that year. These decreases are offset partially by the $7.0 million of expense recognized in 2000 for electric business employees that elected to participate in the TVSERP.

In 1999, regulated electric operations and maintenance expenses were about the same compared to 1998. In 1999, operations and maintenance expenses included the costs for system restoration activities related to Hurricane Floyd and a major winter ice storm. This was offset by lower employee benefit costs in 1999 and a 1998 $6.0 million write-off of contributions to a third party for a low-level radiation waste facility that was never completed.

Electric Depreciation and Amortization Expense

In 2000, regulated electric depreciation and amortization expense decreased $56.5 million compared to 1999 mostly because of the absence of $73.8 million of depreciation and amortization expense associated with the transfer of the generation assets. This decrease was offset partially by more electric plant in service (as our level of plant in service changes, the amount of depreciation and amortization expense changes) and higher amortization associated with regulatory assets.

In 1999, regulated electric depreciation and amortization expense increased $63.4 million compared to 1998 mostly because of the $75.0 million amortization of the regulatory asset for the reduction in generation plant provided for in the Restructuring Order. This increase was offset partially by lower amortization of deferred electric conservation expenditures due to the write-off of a portion of these expenditures that will not be recovered under the Restructuring Order. We discuss the accounting implications of the Restructuring Order further in Note 4 on page 62.

Electric Taxes Other Than Income Taxes

In 2000, regulated electric taxes other than income taxes decreased $31.1 million compared to 1999. This was mostly due to two factors:

- regulated electric taxes other than income taxes reflect the absence of $23.8 million of taxes other than income taxes associated with the generation assets that were transferred to the domestic merchant energy business effective July 1, 2000, and
- comprehensive changes to the tax laws.

The comprehensive tax law changes are discussed further in Note 4 on page 62.

In 1999, regulated electric taxes other than income taxes increased slightly due to higher property and franchise taxes associated with increased electric revenues.

Regulated Gas Business

Earnings

	2000	1999	1998
	(In millions, except per share amounts)		
Gas revenues	**$611.6**	$488.1	$451.1
Gas purchased for resale	**350.6**	233.8	209.4
Operations and maintenance	**100.6**	97.7	97.7
Depreciation and amortization	**46.2**	44.9	45.4
Taxes other than income taxes	**34.8**	34.5	32.5
Income from operations	**$ 79.4**	$ 77.2	$ 66.1
Net income	**$ 30.6**	$ 33.0	$ 26.1
Earnings per share	**$.20**	$.22	$.18

Above amounts include intercompany transactions eliminated in our Consolidated Financial Statements. Note 2 on page 60 provides a reconciliation of operating results by segment to our Consolidated Financial Statements.

All BGE customers have the option to purchase gas from other suppliers. To date, customer choice has not had a material effect on our, and BGE's, financial results.

Gas Revenues

The changes in gas revenues in 2000 and 1999 compared to the respective prior year were caused by:

	2000	1999
	(In millions)	
Gas system sales volumes	**$ 34.5**	$ 8.0
Base rates	**2.7**	2.2
Weather normalization	**(26.7)**	4.5
Gas cost adjustments	**54.7**	19.8
Total change in gas revenues from gas system sales	**65.2**	34.5
Off-system sales	**58.1**	2.0
Other	**0.2**	0.5
Total change in gas revenues	**$123.5**	$37.0

Gas System Sales Volumes

The percentage changes in our gas system sales volumes, by type of customer, in 2000 and 1999 compared to the respective prior year were:

	2000	1999
Residential	**13.0%**	9.2%
Commercial	**12.8**	12.7
Industrial	**(2.1)**	(4.8)

In 2000, we sold more gas to residential and commercial customers compared to 1999 due to higher usage per customer, colder weather, and an increased number of customers. We sold less gas to industrial customers mostly because of lower usage by Bethlehem Steel and other industrial customers, offset partially by an increased number of customers.

In 1999, we sold more gas to residential customers mostly for two reasons: colder winter weather and an increased number of customers. This was offset partially by lower usage per customer. We sold more gas to commercial customers mostly because of higher usage per customer, colder winter weather, and an increased number of customers. We sold less gas to industrial customers mostly because of lower usage by Bethlehem Steel and other industrial customers.

Base Rates

In 2000, base rate revenues increased slightly compared to 1999 mostly because the Maryland PSC authorized a $6.4 million annual increase in our base rates effective June 22, 2000.

In 1999, base rate revenues increased compared to 1998 mostly because of the $16.0 million annual increase in our base rates approved by the Maryland PSC effective March 1, 1998.

Weather Normalization

The Maryland PSC allows us to record a monthly adjustment to our gas revenues to eliminate the effect of abnormal weather patterns on our gas system sales volumes. This means our monthly gas revenues are based on weather that is considered "normal" for the month and, therefore, are not affected by actual weather conditions.

Gas Cost Adjustments

We charge our gas customers for the natural gas they purchase from us using gas cost adjustment clauses set by the Maryland PSC as described in Note 1 on page 54. However, under market based rates, our actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between our actual cost and the market index is shared equally between shareholders and customers, and does not significantly impact earnings.

Delivery service customers, including Bethlehem Steel, are not subject to the gas cost adjustment clauses because we are not selling gas to them. We charge these customers fees to recover the fixed costs for the transportation service we provide. These fees are the same as the base rate charged for gas sales and are included in gas system sales volumes.

In 2000 and 1999, gas cost adjustment revenues increased compared to the respective prior year mostly because we sold more gas at a higher price. In 2000, the revenue increase reflects the significant increase in natural gas prices.

Off-System Sales

Off-system gas sales are low-margin direct sales of gas to wholesale suppliers of natural gas outside our service territory. Off-system gas sales, which occur after we have satisfied our customers' demand, are not subject to gas cost adjustments. The Maryland PSC approved an arrangement for part of the margin from off-system sales to benefit customers (through reduced costs) and the remainder to be retained by BGE (which benefits shareholders).

In 2000, revenues from off-system gas sales increased compared to 1999 mostly because we sold more gas off-system at significantly higher prices.

In 1999, revenues from off-system gas sales were about the same compared to 1998.

Gas Purchased For Resale Expenses

Actual costs include the cost of gas purchased for resale to our customers and for off-system sales. Actual costs do not include the cost of gas purchased by delivery service customers.

In 2000, our gas costs increased compared to 1999 mostly because we bought more gas for off-system sales and all of the gas purchased was at a higher price due to the significant increase in natural gas prices during the year.

In 1999, actual gas costs increased compared to 1998 mostly because we sold more gas.

Other Gas Operating Expenses

In 2000 and 1999, other gas operating expenses were about the same compared to the respective prior year.

Other Nonregulated Businesses

Earnings

	2000	1999	1998
	(In millions, except per share amounts)		
Revenues	**$740.3**	$858.1	$583.0
Operating expenses	**638.0**	821.5	569.4
Depreciation and amortization	**23.0**	23.5	13.9
Taxes other than income taxes	**4.3**	3.9	4.6
Income (loss) from operations	**$ 75.0**	$ 9.2	$ (4.9)
Net income (loss)	**$ 5.6**	$ (24.1)	$ (32.9)
Total earnings per share before nonrecurring charges included in operations:	**$.04**	$.01	$(.09)
Write-down of power project	**—**	(.03)	—
Write-down of financial investment	**—**	(.11)	—
Write-down of real estate and senior-living investments	**—**	(.04)	(.10)
Write-off of energy services investment	**—**	—	(.04)
Earnings per share	**$.04**	$(.17)	$(.23)

Above amounts include intercompany transactions eliminated in our Consolidated Financial Statements. Note 2 on page 60 provides a reconciliation of operating results by segment to our Consolidated Financial Statements.

In 2000, earnings from our other nonregulated businesses increased compared to 1999 mostly because of better market performance of certain of our financial investments. In addition, in 1999, we wrote-down a financial investment, our investment in a generating company in Bolivia, and certain senior-living facilities, which had negative impacts in that year. These increases were offset partially by lower earnings from our Latin American operation primarily due to increased operating expenses in Guatemala.

In 1999, earnings from our other nonregulated businesses increased compared to 1998 mostly because of higher earnings from our Latin American and real estate and senior-living facilities operations. This increase was offset partially by lower earnings from our financial investments operation.

In 1999, earnings from our Latin American operation increased mostly because of higher earnings from the electric distribution company in Panama compared to 1998. In October 1998, an investment group, in which subsidiaries of our Latin American operation hold an 80% interest, purchased 51% of the Panamanian company. This was offset partially by a $4.5 million after-tax write-down of our investment in a generating company in Bolivia to reflect the current fair value of this investment. This write-down was a result of our December 1999 decision to exit the Latin American portion of our business as part of our strategy to improve our competitive position.

In 1999, earnings from our real estate and senior-living facilities operation increased compared to 1998 mostly because of:

- a $15.4 million after-tax write-down of its investment in Church Street Station, an entertainment, dining, and retail complex in Orlando, Florida in 1998 that negatively impacted earnings that year, and
- an increase in earnings from its investment in Corporate Office Properties Trust (COPT) in 1999. We discuss the investment in COPT in Note 3 on page 61.

This increase was offset partially by a $5.8 million after-tax write-down of certain senior-living facilities related to the proposed sale of these facilities in 1999 as discussed below.

Additionally, in 1998, our energy products and services operation recorded a $5.5 million after-tax write-off of an investment in, and certain of our product inventory from, an automated electric distribution equipment company.

In 1999, our financial investments operation announced that it would exchange its shares of common stock in Capital Re, an insurance company, for common stock of ACE, another insurance company, as part of a business combination whereby ACE would acquire all of the outstanding capital stock of Capital Re. As a result, our financial investments operation wrote-down its $94.2 million investment in Capital Re stock by $16.0 million after-tax to reflect the closing price of the business combination. This write-down of Capital Re was offset partially by better market performance of other financial investments in 1999 compared to 1998.

In 1999, our senior-living facilities operation entered into an agreement to sell all but one of its senior-living facilities to Sunrise Assisted Living, Inc. Under the terms of the agreement, Sunrise was to acquire twelve of our existing senior-living facilities, three facilities under construction, and several sites under development for $72.2 million in cash and $16.0 million in debt assumption. We could not reach an agreement on financing issues that subsequently arose, and the agreement was terminated in November 1999. As a result, our senior-living facilities operation engaged a third-party management company to manage its portfolio. However, our senior-living facilities operation recorded a $5.8 million after-tax write-down related to the proposed sale.

Most of Constellation Real Estate Group's real estate and senior-living projects are in the Baltimore-Washington corridor. The area has had a surplus of available land in recent years and as a result these projects have been economically hurt.

Constellation Real Estate's projects have continued to incur carrying costs and depreciation over the years. Additionally, this operation has been charging interest payments to expense rather than capitalizing them for some undeveloped land where development activities have stopped. These carrying costs, depreciation, and interest expenses have decreased earnings and are expected to continue to do so.

Cash flow from real estate and senior-living operations has not been enough to make the monthly loan payments on some of these projects. Cash shortfalls have been covered by cash obtained from the cash flows of, or additional borrowings by, other nonregulated subsidiaries.

We consider market demand, interest rates, the availability of financing, and the strength of the economy in general when making decisions about our real estate and senior-living projects. If we were to decide to sell our projects, we could have write-downs. In addition, if we were to sell our projects in the current market, we would have losses which could be material, although the amount of the losses is hard to predict. Depending on market conditions, we could also have material losses on any future sales.

Our current real estate and senior-living strategy is to hold each project until we can realize a reasonable value for it. Under accounting rules, we are required to write down the value of a project to market value in either of two cases. The first is if we change our intent about a project from an intent to hold to an intent to sell and the market value of that project is below book value. The second is if the expected cash flow from the project is less than the investment in the project.

Consolidated Nonoperating Income and Expenses

Fixed Charges

In 2000, fixed charges increased $16.4 million compared to 1999 mostly because we had more debt outstanding.

In 1999, fixed charges decreased $5.6 million compared to 1998 mostly because we had less BGE preference stock outstanding.

Income Taxes

In 2000, our total income taxes increased $43.7 million compared to 1999 mostly because we had higher taxable income from our nonregulated businesses and an increase in state and local taxes as a result of comprehensive changes to these laws. This increase was offset partially by lower taxable income at BGE. We discuss the comprehensive tax law changes in Note 4 on page 62.

In 1999, income taxes increased $8.7 million compared to 1998 because we had higher taxable income from both our regulated utility operations and our nonregulated businesses.

Financial Condition

Cash Flows

	2000	1999	1998
		(In millions)	
Cash provided by (used in):			
Operating activities	**$ 850.9**	$679.0	$799.8
Investing activities	**(1,106.5)**	(615.1)	(711.3)
Financing activities	**345.6**	(144.9)	(77.4)

In 2000 and 1999, cash provided by operations changed compared to the respective prior year mostly because of changes in working capital requirements.

In 2000, we used more cash for investing activities compared to 1999 mostly due to substantial increases in our domestic merchant energy capital expenditures to support our growth initiatives.

In 1999, we used less cash for investing activities compared to 1998 mostly due to lower investments in Latin American power projects and in the real estate and senior-living facilities operation. This was offset partially by a $97.7 million increase in the investment in Orion, an increase in our investment in domestic power projects, and an increase in capital expenditures by our regulated utility business.

In 2000, we had more cash from financing activities compared to 1999 mostly because we issued more long-term debt and common stock. This was offset partially by an increase in net maturities of short-term borrowings and we repaid more long-term debt.

In 1999, we used more cash for financing activities compared to 1998 mostly because we repaid more long-term debt and issued less long-term debt and common stock. This was offset partially by a decrease in the redemption of BGE preference stock and an increase in our net short-term borrowings.

Security Ratings

Independent credit-rating agencies rate Constellation Energy and BGE's fixed-income securities. The ratings indicate the agencies' assessment of each company's ability to pay interest, distributions, dividends, and principal on these securities. These ratings affect how much it will cost each company to sell these securities. The better the rating, the lower the cost of the securities to each company when they sell them. Constellation Energy and BGE's securities ratings at December 31, 2000 were:

	Standard & Poors Rating Group	Moody's Investors Service	Fitch IBCA
Constellation Energy			
Unsecured Debt	A–	A3	A–
BGE			
Mortgage Bonds	AA–	A1	A+
Unsecured Debt	A	A2	A
Trust Originated Preferred Securities and Preference Stock	A–	"a2"	A–

Capital Resources

Our business requires a great deal of capital. Our actual consolidated capital requirements for the years 1998 through 2000, along with the estimated annual amounts for the years 2001 through 2003, are shown in the table below.

We will continue to have cash requirements for:

- working capital needs including the payments of interest, distributions, and dividends,
- capital expenditures, and
- the retirement of debt and redemption of preference stock.

Capital requirements for 2001 through 2003 include estimates of funding for existing and anticipated projects. We continuously review and modify those estimates. Actual requirements may vary from the estimates included in the table below because of a number of factors including:

- regulation, legislation, and competition,
- BGE load requirements,
- environmental protection standards,
- the type and number of projects selected for development,
- the effect of market conditions on those projects,
- the cost and availability of capital, and
- the availability of cash from operations.

Our estimates are also subject to additional factors. Please see the *Forward Looking Statements* section on page 43.

Effective July 1, 2000, all of BGE's generation assets were transferred to nonregulated subsidiaries of Constellation Energy. The discussion and table for capital requirements below include these generation assets as part of the utility's regulated electric business through June 30, 2000. After that date, the capital requirements are included in the domestic merchant energy business.

	1998	1999	2000	2001	2002	2003
			(In millions)			
Nonregulated Capital Requirements:						
Investment requirements:						
Domestic merchant energy	$ 318	$ 260	$ 801*	$1,692	$ 928	$1,595
Other	7	18	29	50	79	105
Total investment requirements	325	278	830	1,742	1,007	1,700
Retirement of long-term debt	232	189	295	406**	215	200
Total nonregulated capital requirements	557	467	1,125	2,148	1,222	1,900
Utility Capital Requirements:						
Capital expenditures:						
Regulated electric						
Generation (including nuclear fuel)	154	170	95	—	—	—
Transmission and distribution	161	173	170	174	171	173
Total regulated electric	315	343	265	174	171	173
Regulated gas	55	59	55	53	52	52
Common	35	34	30	32	26	20
Total capital expenditures	405	436	350	259	249	245
Retirement of long-term debt and redemption of preference stock	222	342	402	394	320	286
Total utility capital requirements	627	778	752	653	569	531
Total capital requirements	$1,184	$1,245	$1,877	$2,801	$1,791	$2,431

**Effective July 1, 2000, includes $110.6 million for electric generation and nuclear fuel formerly part of BGE's regulated electric business.*

***Amount does not include $1.2 billion in Constellation Energy debt that would be redeemed at or prior to business separation.*

Capital Requirements

Domestic Merchant Energy Business

Our domestic merchant energy business will require additional funding for growing its power marketing operation and developing and acquiring power projects.

Our domestic merchant energy business investment requirements include the planned purchase of the Nine Mile Point nuclear power plant for $815 million, including fuel, and the planned construction of 1,100 megawatts of peaking capacity in the Mid-Atlantic and Mid-West regions by the summer of 2001. An additional 6,700 megawatts of peaking and combined cycle production facilities are scheduled for completion in 2002 and beyond in the Mid-West and South regions. Longer range, our plans are to control approximately 30,000 megawatts of generation capacity by 2005. For further information see the *Strategy* section on page 25.

Electric Generation

Electric construction expenditures for our regulated electric business include improvements to generating plants and costs for replacing the steam generators at Calvert Cliffs through June 30, 2000. Thereafter, these expenditures are reflected in our domestic merchant energy business.

In March 2000, we received the license extension from the Nuclear Regulatory Commission (NRC) that extends our operating licenses at Calvert Cliffs to 2034 for Unit 1 and 2036 for Unit 2. If we do not replace the steam generators, we will not be able to operate these units through our operating license periods. We expect the steam generator replacement to occur during the 2002 refueling outage for Unit 1 and during the 2003 refueling outage for Unit 2. We estimate these Calvert Cliffs' costs to be:

- $ 63 million in 2001,
- $ 91 million in 2002, and
- $ 60 million in 2003.

Additionally, our estimates of future electric generation construction expenditures include the costs of complying with Environmental Protection Agency (EPA) and State of Maryland nitrogen oxides emissions (NOx) reduction regulations as follows:

- $ 71 million in 2001, and
- $ 20 million in 2002.

We discuss the NOx regulations and timing of expenditures in Note 10 on page 71.

Regulated Electric Transmission and Distribution and Gas

Regulated electric transmission and distribution and gas construction expenditures primarily include new business construction needs and improvements to existing facilities.

Funding for Capital Requirements

On October 23, 2000, we announced initiatives designed to advance our growth strategies in the domestic merchant energy business and a change in our common stock dividend policy effective April 2001, as discussed in the *Strategy* section on page 25.

As part of these initiatives, we expect to redeem all of the outstanding debt at Constellation Energy at or prior to the separation of our domestic merchant energy business and remaining businesses. The redemption will occur through a combination of open market purchases, tender offers, and redemption calls. We expect to fund this redemption with short-term debt or other credit facilities, and to refinance this debt longer term after the separation.

Domestic Merchant Energy Business

Funding for the expansion of our domestic merchant energy business is expected from internally generated funds, commercial paper, long-term debt, equity, leases, and other financing instruments issued by Constellation Energy and its subsidiaries. Specifically related to the Nine Mile Point acquisition, one-half of the purchase price, or $407.5 million, is due at the closing of the transaction and the remainder is being financed through the sellers in a note to be repaid over five years with an interest rate of 11.0%. We expect to close the transaction with funds from available sources at that time. Payments on the note over the five years are expected to come from internally generated funds. Longer term, we expect to fund our growth and operating objectives with a mixture of debt and equity with an overall goal of maintaining an investment grade credit profile.

When our domestic merchant energy business separates from our remaining businesses, it initially expects to reinvest its earnings to fund its growth and not to pay a dividend.

Constellation Energy has a commercial paper program where it can issue up to $500 million in short-term notes to fund its nonregulated businesses. To support its commercial paper program, Constellation Energy maintains two revolving credit agreements totaling $565 million, of which one facility can also issue letters of credit. In addition, Constellation Energy has access to interim lines of credit as required from time to time to support its outstanding commercial paper.

BGE

Funding for utility capital expenditures is expected from internally generated funds, commercial paper issuances, available capacity under credit facilities, the issuance of long-term debt, trust securities, or preference stock, and/or from time to time equity contributions from Constellation Energy.

At December 31, 2000, FERC authorized BGE to issue up to $700 million of short-term borrowings, including commercial paper. In addition, BGE maintains $193 million in annual committed bank lines of credit and has $25 million in bank revolving credit agreements to support the commercial paper program. In addition, BGE has access to interim lines of credit as required from time to time to support its outstanding commercial paper.

During the three years from 2001 through 2003, we expect our regulated utility business to provide at least 110% of the cash needed to meet the capital requirements for its operations, excluding cash needed to retire debt.

Other Nonregulated Businesses

BGE Home Products & Services may meet capital requirements through sales of receivables. ComfortLink has a revolving credit agreement totaling $50 million to provide liquidity for short-term financial needs.

If we can get a reasonable value for our real estate projects, senior-living facilities, Latin American operation, and other investments, additional cash may be obtained by selling them. Our ability to sell or liquidate assets will depend on market conditions, and we cannot give assurances that these sales or liquidations could be made. We discuss the real estate and senior-living facilities operation and market conditions in the *Other Nonregulated Businesses* section on page 37.

We discuss our short-term borrowings in Note 7 on page 67 and long-term debt in Note 8 on page 68.

Market Risk

We are exposed to market risk, including changes in interest rates, certain commodity prices, equity prices, and foreign currency. To manage our market risk, we may enter into various derivative instruments including swaps, forward contracts, futures contracts, and options. Effective July 1, 2000, we are subject to additional market risk associated with the purchase and sale of energy as discussed in the *Current Issues* section on page 26. We discuss our market risk further in Note 1 on page 54. In this section, we discuss our current market risk and the related use of derivative instruments.

Interest Rate Risk

We are exposed to changes in interest rates as a result of financing through our issuance of variable-rate and fixed-rate debt. The following table provides information about our obligations that are sensitive to interest rate changes:

Principal Payments and Interest Rate Detail by Contractual Maturity Date

	2001	2002	2003	2004	2005	Thereafter	Total	Fair value at Dec. 31, 2000
				(Dollar amounts in millions)				
Long-term debt								
Variable-rate debt	$317.6	$208.0	$200.2	$ 7.6	$ 5.4	$ 593.0	$1,331.8	$1,243.3
Average interest rate	6.97%	7.30%	7.26%	8.42%	8.62%	5.99%	6.64%	
Fixed-rate debt	$482.5	$327.1	$286.3	$156.0	$347.6	$1,140.0	$2,739.5	$2,819.9
Average interest rate	7.08%	7.01%	6.50%	5.80%	7.72%	6.85%	6.92%	

Commodity Price Risk

We are exposed to the impact of market fluctuations in the price and transportation costs of electricity, natural gas, and other commodities.

Domestic Merchant Energy Business

Our domestic merchant energy business is exposed to market risk from the power marketing operation of Constellation Power Source and from our electric generation operations. Constellation Power Source manages the commodity price risk inherent in its power marketing activities on a portfolio basis, subject to established trading and risk management policies. Commodity price risk arises from the potential for changes in the value of energy commodities and related derivatives due to: changes in commodity prices, volatility of commodity prices, and fluctuations in interest rates. A number of factors associated with the structure and operation of the electricity market significantly influence the level and volatility of prices for energy commodities and related derivative products. These factors include:

- seasonal changes in demand,
- hourly fluctuations in demand due to weather conditions,
- available supply resources,
- transportation availability and reliability within and between regions,
- procedures used to maintain the integrity of the physical electricity system during extreme conditions, and
- changes in the nature and extent of federal and state regulations.

These factors can affect energy commodity and derivative prices in different ways and to different degrees. These effects may vary throughout the country as a result of regional differences in:

- weather conditions,
- market liquidity,
- capability and reliability of the physical electricity and gas systems, and
- the nature and extent of electricity deregulation.

Constellation Power Source uses various methods, including a value at risk model, to measure its exposure to market risk. Value at risk is a statistical model that attempts to predict risk of loss based on historical market price and volatility data. Constellation Power Source calculates value at risk using a variance/covariance technique that models option positions using a linear approximation of their value. Additionally, Constellation Power Source estimates variances and correlation using historical market movements over the most recent rolling three-month period.

The value at risk amount represents the potential loss in the fair value of assets and liabilities from trading activities over a one-day holding period with a 99.6% confidence level. Using this confidence level, Constellation Power Source would expect a one-day change in fair value greater than or equal to the daily value at risk at least once per year. Constellation Power Source's value at risk was $13.7 million as of December 31, 2000 compared to $7.2 million as of December 31, 1999. The average, high, and low value at risk for the year ended December 31, 2000 was $13.1 million, $24.3 million, and $6.3 million, respectively.

Constellation Power Source's value at risk calculation includes all assets and liabilities from its power marketing and trading activities, including energy commodities and derivatives that do not require cash settlements. We believe that this represents a more complete calculation of our value at risk.

Due to the inherent limitations of statistical measures such as value at risk, the relative immaturity of the competitive market for electricity and related derivatives, and the seasonality of changes in market prices, the value at risk calculation may not reflect the full extent of our commodity price risk exposure. Additionally, actual changes in the value of options may differ from the value at risk calculated using a linear approximation inherent in our calculation method. As a result, actual changes in the fair value of assets and liabilities from power marketing and trading activities could differ from the calculated value at risk, and such changes could have a material impact on our financial results. Please refer to the *Forward Looking Statements* section on page 43.

We discuss Constellation Power Source's operation in the *Domestic Merchant Energy Business* section beginning on page 30 and in Note 1 on page 54.

Our domestic merchant energy business conducts electric generation operations primarily through Constellation Power Source Generation, Calvert Cliffs, and Constellation Power. Presently, the majority of the generating capacity controlled by our domestic merchant energy business is used to provide standard offer service to BGE. However, beginning in July 2002, we expect approximately 1,000 megawatts of industrial customer load will leave standard offer service. The remainder of the standard offer service arrangement with BGE terminates on June 30, 2003. Additionally, we plan to expand our generation operations as discussed in the *Strategy* section on page 25.

As a result, our domestic merchant energy business has a substantial and increasing amount of generating capacity that is subject to future changes in wholesale electricity prices and has fuel requirements that are subject to future changes in coal, natural gas, and oil prices. Additionally, if one or more of our generating facilities is not able to produce electricity when required due to operational factors, we may have to forego sales opportunities or fulfill fixed price sale commitments through the operation of other more costly generating facilities or through the purchase of energy in the wholesale market at higher prices.

Constellation Power Source manages the commodity price risk of our electric generation operations as part of its overall portfolio. Additionally, the domestic merchant energy business may enter into fixed-price contracts to hedge a portion of its exposure to future electricity and fuel commodity price risk.

Regulated Electric Business

The standard offer service arrangement between BGE and Constellation Power Source ends June 30, 2003. Under the Restructuring Order, effective July 1, 2000, BGE's residential rates are frozen for a six-year period and its commercial and industrial rates are frozen for four to six years. As a result, BGE will be subject to commodity price risk beginning July 1, 2003 upon termination of the existing standard offer arrangement. In accordance with the Restructuring Order, BGE will competitively bid the standard offer service supply for the remaining period of the rate freeze subsequent to June 30, 2003. During the remaining period of BGE's rate freeze, BGE will be unable to pass through to its customers any increase in the market price of electricity it must purchase to meet the standard offer service load. Our regulated electric business is evaluating various alternatives to minimize the market risk after June 30, 2003.

Regulated Gas Business

Our regulated gas business may enter into gas futures, options, and swaps to hedge its price risk under our market based rate incentive mechanism and our off-system gas sales program. We discuss this further in Note 1 on page 55. At December 31, 2000 and 1999, our exposure to commodity price risk for our regulated gas business was not material.

Credit Risk

We are exposed to credit risk, primarily through Constellation Power Source. Credit risk is the loss that may result from a counterparty's nonperformance. Constellation Power Source uses credit policies to control its credit risk, including utilizing an established credit approval process, monitoring counterparty limits, employing credit mitigation measures such as margin, collateral or prepayment arrangements, and using master netting agreements. However, due to the possibility of extreme volatility in the prices of electricity commodities and derivatives, the market value of contractual positions with individual counterparties could exceed established credit limits or collateral provided by those counterparties. If such a counterparty were then to fail to perform its obligations under its contract (for example, fail to deliver the electricity Constellation Power Source had contracted for), Constellation Power Source could sustain a loss that could have a material impact on our financial results.

Our domestic merchant energy business sells electricity to two California investor-owned utilities under long-term power purchase agreements that recently were downgraded by rating agencies to below investment grade. We discuss the credit and other exposures under these agreements in the *Current Issues* section on page 27.

Equity Price Risk

We are exposed to price fluctuations in equity markets primarily through our financial investments operation and our nuclear decommissioning trust fund. We are required by the NRC to maintain a trust to fund the costs of decommissioning Calvert Cliffs. We believe our exposure to fluctuations in equity prices will not have a material impact on our financial results. We discuss our nuclear decommissioning trust fund in more detail in Note 1 on page 58. We also describe our financial investments in more detail in Note 3 on page 61.

Foreign Currency Risk

We are exposed to foreign currency risk primarily through our Latin American operation. Our Latin American operation has $255.9 million invested in international power generation and distribution projects as of December 31, 2000. To manage our exposure to foreign currency risk, the majority of our contracts are denominated in or indexed to the U.S. dollar. At December 31, 2000 and 1999, foreign currency risk was not material. We discuss our international projects in the *Other Nonregulated Businesses* section on page 37.

FORWARD LOOKING STATEMENTS

We make statements in this report that are considered forward looking statements within the meaning of the Securities Exchange Act of 1934. Sometimes these statements will contain words such as "believes," "expects," "intends," "plans," and other similar words. These statements are not guarantees of our future performance and are subject to risks, uncertainties and other important factors that could cause our actual performance or achievements to be materially different from those we project. These risks, uncertainties, and factors include, but are not limited to:

- satisfaction of all the conditions precedent to the closing on the purchase of the Nine Mile Point nuclear power plant, including obtaining all regulatory approvals,
- obtaining all regulatory approvals necessary to close on the investment by an affiliate of Goldman Sachs in our domestic merchant energy business and complete the separation of our domestic merchant energy business from our remaining businesses,
- satisfaction of all conditions precedent to the transaction with Goldman Sachs,
- general economic, business, and regulatory conditions,
- the pace and nature of deregulation nationwide (including the status of the California markets),
- energy supply and demand,
- competition,
- federal and state regulations,
- availability, terms, and use of capital,
- nuclear and environmental issues,
- weather,
- implications of the Restructuring Order issued by the Maryland PSC, including the outcome of the appeal,
- commodity price risk,
- operating our generation assets in a deregulated market without the benefit of a fuel rate adjustment clause,
- loss of revenue due to customers choosing alternative suppliers,
- higher volatility of earnings and cash flows,
- increased financial requirements of our nonregulated subsidiaries,
- inability to recover all costs associated with providing electric retail customers service during the electric rate freeze period, and
- implications from the transfer of BGE's generation assets and related liabilities to nonregulated subsidiaries of Constellation Energy, including the outcome of the appeal of the Maryland PSC's Order regarding the transfer of generation assets.

Given these uncertainties, you should not place undue reliance on these forward looking statements. Please see the other sections of this report and our other periodic reports filed with the SEC for more information on these factors. These forward looking statements represent our estimates and assumptions only as of the date of this report.

REPORT OF MANAGEMENT

The management of the Company is responsible for the information and representations in the Company's financial statements. The Company prepares the financial statements in accordance with accounting principles generally accepted in the United States of America based upon available facts and circumstances and management's best estimates and judgments of known conditions.

The Company maintains an accounting system and related system of internal controls designed to provide reasonable assurance that the financial records are accurate and that the Company's assets are protected. The Company's staff of internal auditors, which reports directly to the Chairman of the Board, conducts periodic reviews to maintain the effectiveness of internal control procedures. PricewaterhouseCoopers LLP, independent accountants, audit the financial statements and express their opinion on them. They perform their audit in accordance with auditing standards generally accepted in the United States of America.

The Audit Committee of the Board of Directors, which consists of four outside Directors, meets periodically with management, internal auditors, and PricewaterhouseCoopers LLP to review the activities of each in discharging their responsibilities. The internal audit staff and PricewaterhouseCoopers LLP have free access to the Audit Committee.

C.H. Poindexter

Christian H. Poindexter
Chairman of the Board
and Chief Executive Officer

David A. Brune

David A. Brune
Chief Financial Officer

REPORT OF INDEPENDENT ACCOUNTANTS

To the Shareholders of Constellation Energy Group, Inc.

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, comprehensive income, cash flows, common shareholders' equity, capitalization and income taxes present fairly, in all material respects, the financial position of Constellation Energy Group, Inc. and Subsidiaries at December 31, 2000 and 1999, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2000 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for the opinion expressed above.

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Baltimore, Maryland
January 17, 2001

CONSOLIDATED STATEMENTS OF INCOME

Year Ended December 31,	**2000**	1999	1998
	(In millions, except per share amounts)		
Revenues			
Nonregulated revenues	**$1,140.0**	$1,050.9	$ 717.8
Regulated electric revenues	**2,134.7**	2,258.8	2,219.2
Regulated gas revenues	**603.8**	476.5	449.4
Total revenues	**3,878.5**	3,786.2	3,386.4
Expenses			
Operating expenses	**2,347.3**	2,349.2	2,053.0
Depreciation and amortization	**470.0**	449.8	375.5
Taxes other than income taxes	**221.0**	227.3	219.4
Total expenses	**3,038.3**	3,026.3	2,647.9
Income from Operations	**840.2**	759.9	738.5
Other Income	**6.6**	7.9	5.7
Income Before Fixed Charges and Income Taxes	**846.8**	767.8	744.2
Fixed Charges			
Interest expense (net)	**258.2**	241.5	238.8
BGE preference stock dividends	**13.2**	13.5	21.8
Total fixed charges	**271.4**	255.0	260.6
Income Before Income Taxes	**575.4**	512.8	483.6
Income Taxes	**230.1**	186.4	177.7
Income Before Extraordinary Item	**345.3**	326.4	305.9
Extraordinary Loss, Net of Income Taxes of $30.4 (see Note 4)	**—**	(66.3)	—
Net Income	**$ 345.3**	$ 260.1	$ 305.9
Earnings Applicable to Common Stock	**$ 345.3**	$ 260.1	$ 305.9
Average Shares of Common Stock Outstanding	**150.0**	149.6	148.5
Earnings Per Common Share and Earnings Per Common Share—Assuming Dilution Before Extraordinary Item	**$2.30**	$2.18	$2.06
Extraordinary Loss	**—**	(.44)	—
Earnings Per Common Share and Earnings Per Common Share—Assuming Dilution	**$2.30**	$1.74	$2.06

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year Ended December 31,	**2000**	1999	1998
		(In millions)	
Net Income	**$345.3**	$260.1	$305.9
Other comprehensive income/(loss), net of taxes	**22.1**	(6.2)	1.2
Comprehensive Income	**$367.4**	$253.9	$307.1

See Notes to Consolidated Financial Statements.
Certain prior-year amounts have been reclassified to conform with the current year's presentation.

CONSOLIDATED BALANCE SHEETS

At December 31,	2000	1999
	(In millions)	
Assets		
Current Assets		
Cash and cash equivalents	**$ 182.7**	$ 92.7
Accounts receivable (net of allowance for uncollectibles of $21.3 and $34.8, respectively)	**738.5**	578.5
Trading securities	**189.3**	136.5
Assets from energy trading activities	**2,056.5**	312.1
Fuel stocks	**78.2**	94.9
Materials and supplies	**151.3**	149.1
Prepaid taxes other than income taxes	**73.5**	72.4
Other	**32.7**	54.0
Total current assets	**3,502.7**	1,490.2
Investments and Other Assets		
Real estate projects and investments	**290.3**	310.1
Investments in power projects	**517.5**	513.9
Financial investments	**161.0**	145.4
Nuclear decommissioning trust fund	**228.7**	217.9
Net pension asset	**93.2**	99.5
Investment in Orion Power Holdings, Inc.	**192.0**	105.7
Other	**123.0**	154.3
Total investments and other assets	**1,605.7**	1,546.8
Property, Plant and Equipment		
Regulated property, plant and equipment		
Plant in service	**4,780.3**	8,620.1
Construction work in progress	**75.3**	222.3
Plant held for future use	**4.5**	13.0
Total regulated property, plant and equipment	**4,860.1**	8,855.4
Nonregulated generation property, plant and equipment	**5,279.9**	374.7
Other nonregulated property, plant and equipment	**173.8**	152.7
Nuclear fuel (net of amortization)	**128.3**	133.8
Accumulated depreciation	**(3,798.1)**	(3,559.1)
Net property, plant and equipment	**6,644.0**	5,957.5
Deferred Charges		
Regulatory assets (net)	**514.9**	637.4
Other	**117.3**	51.9
Total deferred charges	**632.2**	689.3
Total Assets	**$12,384.6**	$9,683.8

See Notes to Consolidated Financial Statements.
Certain prior-year amounts have been reclassified to conform with the current year's presentation.

At December 31,	2000	1999
	(In millions)	
Liabilities and Capitalization		
Current Liabilities		
Short-term borrowings	**$ 243.6**	$ 371.5
Current portion of long-term debt	**906.6**	808.3
Accounts payable	**695.9**	365.1
Liabilities from energy trading activities	**1,586.8**	163.8
Dividends declared	**66.5**	66.1
Accrued taxes	**38.2**	19.2
Other	**212.6**	209.4
Total current liabilities	**3,750.2**	2,003.4
Deferred Credits and Other Liabilities		
Deferred income taxes	**1,339.5**	1,288.8
Postretirement and postemployment benefits	**265.2**	269.8
Deferred investment tax credits	**101.4**	109.6
Other	**426.0**	253.8
Total deferred credits and other liabilities	**2,132.1**	1,922.0
Capitalization		
Long-term debt	**3,159.3**	2,575.4
BGE preference stock not subject to mandatory redemption	**190.0**	190.0
Common shareholders' equity	**3,153.0**	2,993.0
Total capitalization	**6,502.3**	5,758.4
Commitments, Guarantees, and Contingencies (see Note 10)		
Total Liabilities and Capitalization	**$12,384.6**	$9,683.8

See Notes to Consolidated Financial Statements.
Certain prior-year amounts have been reclassified to conform with the current year's presentation.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year Ended December 31,	**2000**	1999	1998
		(In millions)	
Cash Flows From Operating Activities			
Net income	**$ 345.3**	$ 260.1	$ 305.9
Adjustments to reconcile to net cash provided by operating activities			
Extraordinary loss	**—**	66.3	—
Depreciation and amortization	**524.8**	505.9	427.8
Deferred income taxes	**42.0**	13.0	17.5
Investment tax credit adjustments	**(8.3)**	(8.6)	(8.8)
Deferred fuel costs	**2.8**	(61.1)	(8.3)
Accrued pension and postemployment benefits	**27.9**	36.1	41.6
Gain on sale of subsidiaries	**(13.3)**	—	—
Gain on sale of Orion Power Holdings, Inc. stock	**(19.2)**	—	—
Deregulation transition cost	**24.0**	—	—
Write-downs of real estate investments	**—**	9.6	23.7
Write-down of financial investment	**—**	26.2	—
Write-downs of power projects	**—**	28.5	—
Equity in earnings of affiliates and joint ventures (net)	**(5.3)**	(7.6)	(54.5)
Changes in assets from energy trading activities	**(1,744.4)**	(179.1)	(123.6)
Changes in liabilities from energy trading activities	**1,423.0**	64.8	90.4
Changes in other current assets	**(176.6)**	(216.4)	18.3
Changes in other current liabilities	**352.1**	121.0	77.0
Other	**76.1**	20.3	(7.2)
Net cash provided by operating activities	**850.9**	679.0	799.8
Cash Flows From Investing Activities			
Purchases of property, plant and equipment and other capital expenditures	**(1,079.0)**	(616.5)	(730.2)
Investment in Orion	**(101.5)**	(97.7)	—
Contributions to nuclear decommissioning trust fund	**(13.2)**	(17.6)	(17.6)
Purchases of marketable equity securities	**(80.8)**	(27.3)	(33.3)
Sales of marketable equity securities	**110.2**	34.9	32.8
Other investments	**57.8**	109.1	37.0
Net cash used in investing activities	**(1,106.5)**	(615.1)	(711.3)
Cash Flows From Financing Activities			
Net (maturity) issuance of short-term borrowings	**(127.9)**	371.5	(316.1)
Proceeds from issuance of			
Long-term debt	**1,374.0**	302.8	831.3
Common stock	**35.9**	9.6	51.8
Reacquisition of long-term debt	**(697.0)**	(584.4)	(355.2)
Redemption of preference stock	**—**	(7.0)	(127.9)
Common stock dividends paid	**(250.7)**	(251.1)	(246.0)
Other	**11.3**	13.7	84.7
Net cash provided by (used in) financing activities	**345.6**	(144.9)	(77.4)
Net Increase (Decrease) in Cash and Cash Equivalents	**90.0**	(81.0)	11.1
Cash and Cash Equivalents at Beginning of Year	**92.7**	173.7	162.6
Cash and Cash Equivalents at End of Year	**$ 182.7**	$ 92.7	$ 173.7
Other Cash Flow Information			
Cash paid during the year for:			
Interest (net of amounts capitalized)	**$ 268.2**	$ 245.3	$ 236.7
Income taxes	**$ 184.7**	$ 165.6	$ 164.3

Noncash Investing and Financing Activities:

In 1998, Corporate Office Properties Trust (COPT) assumed approximately $62 million of Constellation Real Estate Group's (CREG) debt and issued to CREG 7.0 million common shares and 985,000 convertible preferred shares. In exchange, COPT received 14 operating properties and two properties under development from CREG.

See Notes to Consolidated Financial Statements.

Certain prior-year amounts have been reclassified to conform with the current year's presentation.

CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS' EQUITY

Years Ended December 31, 2000, 1999, and 1998	Common Stock Shares	Common Stock Amount	Retained Earnings	Accumulated Other Comprehensive Income	Total Amount
	(Dollar amounts in millions, number of shares in thousands)				
Balance at December 31, 1997	147,667	$1,433.0	$1,432.5	$ 4.9	$2,870.4
Net income			305.9		305.9
Common stock dividend declared ($1.67 per share)			(248.1)		(248.1)
Common stock issued	1,579	51.8			51.8
Other		0.3			0.3
Net unrealized gain on securities				1.8	1.8
Deferred taxes on net unrealized gain on securities				(0.6)	(0.6)
Balance at December 31, 1998	149,246	1,485.1	1,490.3	6.1	2,981.5
Net income			260.1		260.1
Common stock dividend declared ($1.68 per share)			(251.3)		(251.3)
Common stock issued	310	9.6			9.6
Other		(0.7)			(0.7)
Net unrealized loss on securities				(9.6)	(9.6)
Deferred taxes on net unrealized loss on securities				3.4	3.4
Balance at December 31, 1999	149,556	1,494.0	1,499.1	(0.1)	2,993.0
Net income			**345.3**		**345.3**
Common stock dividend declared ($1.68 per share)			**(251.8)**		**(251.8)**
Common stock issued	**976**	**35.9**			**35.9**
Other		**8.8**	**(0.3)**		**8.5**
Net unrealized gain on securities				**33.9**	**33.9**
Deferred taxes on net unrealized gain on securities				**(11.8)**	**(11.8)**
Balance at December 31, 2000	**150,532**	**$1,538.7**	**$1,592.3**	**$22.0**	**$3,153.0**

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CAPITALIZATION

At December 31,	**2000**	1999
	(In millions)	
Long-Term Debt		
Long-term debt of Constellation Energy		
7⅞% Notes, due April 1, 2005	**$ 300.0**	$ —
Floating rate notes, due April 4, 2003	**200.0**	—
Extendible notes, due June 21, 2010	**300.0**	—
Floating rate reset notes, due March 15, 2002	**200.0**	—
Total long-term debt of Constellation Energy	**1,000.0**	—
Long-term debt of nonregulated businesses		
Tax-exempt debt transferred from BGE effective July 1, 2000		
Pollution control loan, due July 1, 2011	**36.0**	—
Port facilities loan, due June 1, 2013	**48.0**	—
Adjustable rate pollution control loan, due July 1, 2014	**20.0**	—
5.55% Pollution control revenue refunding loan, due July 15, 2014	**47.0**	—
Economic development loan, due December 1, 2018	**35.0**	—
6.00% Pollution control revenue refunding loan, due April 1, 2024	**75.0**	—
Floating rate pollution control loan, due June 1, 2027	**8.8**	—
5½% Installment series, due July 15, 2002	**7.6**	—
Loan under revolving credit agreement	**34.0**	33.0
Mortgage and construction loans		
Floating rate mortgage notes and construction loans, due through 2005	**51.3**	112.0
Other mortgage notes ranging from 4.25% to 9.65% due July 31, 2001 to November 1, 2033	**20.3**	30.8
Unsecured notes	**287.0**	511.0
Total long-term debt of nonregulated businesses	**670.0**	686.8
First Refunding Mortgage Bonds of BGE		
5½% Series, due July 15, 2000 transferred to nonregulated businesses effective July 1, 2000	**—**	124.3
8⅜% Series, due August 15, 2001	**122.2**	122.3
7¼% Series, due July 1, 2002	**124.0**	124.5
6½% Series, due February 15, 2003	**124.8**	124.8
6⅛% Series, due July 1, 2003	**124.9**	124.9
5½% Series, due April 15, 2004	**125.0**	125.0
Remarketed floating rate series, due September 1, 2006	**111.5**	125.0
7½% Series, due January 15, 2007	**123.5**	123.5
6⅝% Series, due March 15, 2008	**124.9**	124.9
7½% Series, due March 1, 2023	**109.9**	109.9
7½% Series, due April 15, 2023	**84.0**	84.1
Tax-exempt debt transferred to nonregulated businesses effective July 1, 2000	**—**	8.5
Total First Refunding Mortgage Bonds of BGE	**1,174.7**	1,321.7
Other long-term debt of BGE		
Floating rate reset notes, due October 19, 2001	**200.0**	—
Medium-term notes, Series B	**23.1**	60.0
Medium-term notes, Series C	**25.5**	101.0
Medium-term notes, Series D	**128.0**	128.0
Medium-term notes, Series E	**200.0**	200.0
Medium-term notes, Series G	**200.0**	200.0
Medium-term notes, Series H	**27.0**	177.0
6.75% Remarketable or redeemable securities, due December 15, 2012	**173.0**	—
Tax-exempt debt transferred to nonregulated businesses effective July 1, 2000	**—**	269.8
Total other long-term debt of BGE	**976.6**	1,135.8
BGE obligated mandatorily redeemable trust preferred securities of subsidiary trust holding solely 7.16% debentures of BGE due June 30, 2038	**250.0**	250.0
Unamortized discount and premium	**(5.4)**	(10.6)
Current portion of long-term debt	**(906.6)**	(808.3)
Total long-term debt	**$3,159.3**	$2,575.4

See Notes to Consolidated Financial Statements.

Certain prior-year amounts have been reclassified to conform with the current year's presentation.

continued on page 51

At December 31,	**2000**	1999
	(In millions)	
BGE Preference Stock		
Cumulative preference stock not subject to mandatory redemption, 6,500,000 shares authorized		
7.125%, 1993 Series, 400,000 shares outstanding, not callable prior to July 1, 2003	**$ 40.0**	$ 40.0
6.97%, 1993 Series, 500,000 shares outstanding, not callable prior to October 1, 2003	**50.0**	50.0
6.70%, 1993 Series, 400,000 shares outstanding, not callable prior to January 1, 2004	**40.0**	40.0
6.99%, 1995 Series, 600,000 shares outstanding, not callable prior to October 1, 2005	**60.0**	60.0
Total preference stock not subject to mandatory redemption	**190.0**	190.0
Common Shareholders' Equity		
Common stock without par value, 250,000,000 shares authorized; 150,531,716 and 149,556,416 shares issued and outstanding at December 31, 2000 and 1999, respectively. (At December 31, 2000 166,893 shares were reserved for the Employee Savings Plan and 12,061,756 shares were reserved for the Shareholder Investment Plan.)	**1,538.7**	1,494.0
Retained earnings	**1,592.3**	1,499.1
Accumulated other comprehensive income (loss)	**22.0**	(0.1)
Total common shareholders' equity	**3,153.0**	2,993.0
Total Capitalization	**$6,502.3**	$5,758.4

See Notes to Consolidated Financial Statements.

Certain prior-year amounts have been reclassified to conform with the current year's presentation.

CONSOLIDATED STATEMENTS OF INCOME TAXES

Year Ended December 31,	**2000**	1999	1998
		(Dollar amounts in millions)	
Income Taxes			
Current	**$196.4**	$182.0	$169.0
Deferred			
Change in tax effect of temporary differences	**50.4**	9.6	14.2
Change in income taxes recoverable through future rates	**3.4**	—	3.9
Deferred taxes credited (charged) to shareholders' equity	**(11.8)**	3.4	(0.6)
Deferred taxes charged to expense	**42.0**	13.0	17.5
Investment tax credit adjustments	**(8.3)**	(8.6)	(8.8)
Income taxes per Consolidated Statements of Income	**$230.1**	$186.4	$177.7
Reconciliation of Income Taxes Computed at Statutory Federal Rate to Total Income Taxes			
Income before income taxes (excluding BGE preference stock dividends)	**$588.6**	$526.3	$505.4
Statutory federal income tax rate	**35%**	35%	35%
Income taxes computed at statutory federal rate	**206.0**	184.2	176.9
Increases (decreases) in income taxes due to			
Depreciation differences not normalized on regulated activities	**12.6**	15.3	13.6
Allowance for equity funds used during construction	**(0.9)**	(2.2)	(2.2)
Amortization of deferred investment tax credits	**(8.3)**	(8.6)	(8.8)
Tax credits flowed through to income	**(6.5)**	(3.2)	(0.3)
Amortization of deferred tax rate differential on regulated activities	**(2.9)**	(3.0)	(2.3)
State income taxes	**34.0**	8.9	9.8
Other	**(3.9)**	(5.0)	(9.0)
Total income taxes	**$230.1**	$186.4	$177.7
Effective income tax rate	**39.1%**	35.4%	35.2%

At December 31,	**2000**	1999
	(Dollar amounts in millions)	
Deferred Income Taxes		
Deferred tax liabilities		
Net property, plant and equipment	**$1,121.1**	$1,102.6
Income taxes recoverable through future rates	**32.8**	35.7
Deferred termination and postemployment costs	**13.6**	14.7
Deferred fuel costs	**24.9**	25.8
Leveraged leases	**17.0**	19.9
Energy trading activities	**1,691.8**	71.4
Deferred electric generation-related regulatory assets	**93.7**	100.3
Other	**161.7**	192.6
Total deferred tax liabilities	**3,156.6**	1,563.0
Deferred tax assets		
Accrued pension and postemployment benefit costs	**76.5**	63.6
Deferred investment tax credits	**35.5**	38.3
Nuclear decommissioning liability	**28.2**	25.4
Energy trading activities	**1,510.6**	15.1
Other	**166.3**	131.8
Total deferred tax assets	**1,817.1**	274.2
Deferred tax liability, net	**$1,339.5**	$1,288.8

See Notes to Consolidated Financial Statements.

Certain prior-year amounts have been reclassified to conform with the current year's presentation.

1 Significant Accounting Policies

Nature of Our Business

Constellation Energy® Group, Inc. (Constellation Energy) is a diversified North American energy company. Constellation Energy conducts its business through various subsidiaries that primarily include a domestic merchant energy business and Baltimore Gas and Electric Company (BGE®). Our domestic merchant energy business is focused mostly on power marketing and merchant generation in North America. BGE is an electric and gas public utility distribution company with a service territory that covers the City of Baltimore and all or part of ten counties in Central Maryland. We describe our operating segments in Note 2 on page 59.

References in this report to "we" and "our" are to Constellation Energy and its subsidiaries, collectively. Reference in this report to the "utility business" is to BGE.

On April 30, 1999, Constellation Energy became the holding company for BGE and Constellation® Enterprises, Inc. Constellation Enterprises was previously owned by BGE. BGE's outstanding common stock automatically became shares of common stock of Constellation Energy. BGE's debt securities, obligated mandatorily redeemable trust preferred securities, and preference stock remain securities of BGE, or its subsidiaries.

Consolidation Policy

We use three different accounting methods to report our investments in our subsidiaries or other companies: consolidation, the equity method, and the cost method.

Consolidation

We use consolidation when we own a majority of the voting stock of the subsidiary. This means the accounts of our subsidiaries are combined with our accounts. We eliminate intercompany balances and transactions when we consolidate these accounts. Our consolidated financial statements include the accounts of:

- Constellation Energy,
- BGE and its subsidiaries,
- Constellation Enterprises, Inc. and its subsidiaries, and
- Constellation Nuclear Group, LLC and its subsidiaries.

The Equity Method

We usually use the equity method to report investments, corporate joint ventures, partnerships, and affiliated companies (including power projects) where we hold a 20% to 50% voting interest. Under the equity method, we report:

- our interest in the entity as an investment in our Consolidated Balance Sheets beginning on page 46, and
- our percentage share of the earnings from the entity in our Consolidated Statements of Income on page 45.

The only time we do not use this method is if we can exercise control over the operations and policies of the company. If we have control, accounting rules require us to use consolidation.

The Cost Method

We usually use the cost method if we hold less than a 20% voting interest in an investment. Under the cost method, we report our investment at cost in our Consolidated Balance Sheets. The only time we do not use this method is when we can exercise significant influence over the operations and policies of the company. If we have significant influence, accounting rules require us to use the equity method.

Regulation of Utility Business

The Maryland Public Service Commission (Maryland PSC) provides the final determination of the rates we charge our customers for our regulated businesses. Generally, we use the same accounting policies and practices used by nonregulated companies for financial reporting under accounting principles generally accepted in the United States of America. However, sometimes the Maryland PSC orders an accounting treatment different from that used by nonregulated companies to determine the rates we charge our customers. When this happens, we must defer certain utility expenses and income in our Consolidated Balance Sheets as regulatory assets and liabilities. We have recorded these regulatory assets and liabilities in our Consolidated Balance Sheets in accordance with Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation.* We summarize and discuss our regulatory assets and liabilities further in Note 5 on page 64.

In 1997, the Financial Accounting Standards Board (FASB) through its Emerging Issues Task Force (EITF) issued EITF 97-4, *Deregulation of the Pricing of Electricity—Issues Related to the Application of FASB Statements No. 71 and 101.* The EITF concluded that a company should cease to apply SFAS No. 71 when either legislation is passed or a regulatory body issues an order that contains sufficient detail to determine how the transition plan will affect the deregulated portion of the business. Additionally, a company would continue to recognize regulatory assets and liabilities in the Consolidated Balance Sheets to the extent that the transition plan provides for their recovery.

On November 10, 1999, the Maryland PSC issued a Restructuring Order that we believe provided sufficient details of the transition plan to competition for BGE's electric generation business to require BGE to discontinue the application of SFAS No. 71 for that portion of its business. Accordingly, in the fourth quarter of 1999, we adopted the provisions of SFAS No. 101, *Regulated Enterprises—Accounting for the Discontinuation of FASB Statement No. 71* and EITF No. 97-4 for BGE's electric generation business. BGE's transmission and distribution business continues to meet the requirements of SFAS No. 71 as that business remains regulated. We discuss this further in Note 4 on page 63.

Revenues

Nonregulated Businesses

We record nonregulated revenues in our Consolidated Statements of Income in the period earned for services rendered, commodities or products delivered, or contracts settled.

Our subsidiary, Constellation Power Source, engages in power marketing activities, which include trading electricity, other energy commodities, and related derivatives (such as futures, forwards, options, and swaps). Constellation Power Source accounts for its activities using the mark-to-market method of accounting in accordance with EITF Issue 98-10, *Accounting for Contracts Involved in Energy Trading and Risk Management Activities*.

Under the mark-to-market method of accounting, we report:

- commodity positions and derivatives at fair value as "Assets from energy trading activities" or "Liabilities from energy trading activities" in our Consolidated Balance Sheets, and
- changes in fair value and net gains and losses from realized transactions as components of "Nonregulated revenues" in our Consolidated Statements of Income.

Changes in fair value result primarily from new transactions and the impact of price and interest rate movements.

Regulated Utility

We record utility revenues when we provide service to customers.

Fuel and Purchased Energy Costs

We incur costs for:

- the fuel we use to generate electricity,
- purchases of electricity from others, and
- natural gas that we resell.

These costs are included in "Operating expenses" in our Consolidated Statements of Income. We discuss each of these separately below.

Fuel Used to Generate Electricity and Purchases of Electricity From Others

Effective July 1, 2000, these costs are recorded as incurred. Historically and until July 1, 2000, we were allowed to recover our costs of electric fuel under the electric fuel rate clause set by the Maryland PSC. Under the electric fuel rate clause, we charged our electric customers for:

- the fuel we use to generate electricity (nuclear fuel, coal, gas, or oil), and
- the net cost of purchases and sales of electricity.

We charged the actual costs of these items to customers with no profit to us. To do this, we had to keep track of what we spent and what we collected from customers under the fuel rate in a given period. Usually these two amounts were not the same because there was a difference between the time we spent the money and the time we collected it from our customers.

Under the electric fuel rate clause, we deferred (included as an asset or liability in our Consolidated Balance Sheets and excluded from our Consolidated Statements of Income) the difference between our actual costs of fuel and energy and what we collected from customers under the fuel rate in a given period. We either billed or refunded our customers that difference in the future. As a result of the Restructuring Order, the fuel rate was discontinued effective July 1, 2000. We discuss this further in Note 5 on page 65.

Natural Gas

We charge our gas customers for the natural gas they purchase from us using "gas cost adjustment clauses" set by the Maryland PSC. These clauses operate similarly to the electric fuel rate clause described earlier in this note. However, the Maryland PSC approved a modification of the gas cost adjustment clauses to provide a market based rates incentive mechanism. Under market based rates our actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between our actual cost and the market index is shared equally between shareholders and customers.

Risk Management

We are exposed to the impact of market fluctuations in the price and transportation costs of electricity, natural gas, and other commodities. Our domestic merchant energy and regulated gas businesses use derivative instruments to manage changes in their respective commodity prices. We discuss our risk management activities in more detail below.

Domestic Merchant Energy Business

Our domestic merchant energy business is exposed to market risk from the power marketing operation of Constellation Power Source and from our electric generation operations. Constellation Power Source manages the market risk inherent in its power marketing activities on a portfolio basis, subject to established trading and risk management policies. Constellation Power Source uses a variety of derivative instruments, including:

- forward contracts, which commit us to purchase or sell energy commodities in the future;
- futures contracts, which are exchange-traded standardized commitments to purchase or sell a commodity or financial instrument, or to make a cash settlement, at a specific price and future date;
- swap agreements, which require payments to or from counterparties based upon the differential between two prices for a predetermined contractual (notional) amount; and
- option contracts, which convey the right to buy or sell a commodity, financial instrument, or index at a predetermined price.

Market risk arises from the potential for changes in the value of energy commodities and related derivatives due to: changes in commodity prices, volatility of commodity prices, and fluctuations in interest rates. A number of factors associated with the structure and operation of the electricity market significantly influence the level and volatility of prices for energy commodities and related derivative products. These factors include:

- seasonal changes in demand,
- hourly fluctuations in demand due to weather conditions,
- available supply resources,
- transportation availability and reliability within and between regions,
- procedures used to maintain the integrity of the physical electricity system during extreme conditions, and
- changes in the nature and extent of federal and state regulations.

These factors can affect energy commodity and derivative prices in different ways and to different degrees. These effects may vary throughout the country as a result of regional differences in:

- weather conditions,
- market liquidity,
- capability and reliability of the physical electricity and gas systems, and
- the nature and extent of electricity deregulation.

Our domestic merchant energy business conducts electric generation operations primarily through Constellation Power Source Generation, Calvert Cliffs, and Constellation Power. Presently, the majority of the generating capacity controlled by our domestic merchant energy business is used to provide standard offer service to BGE. However, beginning in July 2002, we expect approximately 1,000 megawatts of industrial customer load will leave standard offer service. The remainder of the standard offer service arrangement with BGE terminates on June 30, 2003. Additionally, we plan to expand our generation operations.

As a result, our domestic merchant energy business has a substantial and increasing amount of generating capacity that is subject to future changes in wholesale electricity prices and has fuel requirements that are subject to future changes in coal, natural gas, and oil prices. Additionally, if one or more of our generating facilities is not able to produce electricity when required due to operational factors, we may have to forego sales opportunities or fulfill fixed price sale commitments through the operation of other more costly generating facilities or through the purchase of energy in the wholesale market at higher prices.

Constellation Power Source manages the commodity price risk of our electric generation operations as part of its overall portfolio. Additionally, the domestic merchant energy business may enter into fixed-price contracts to hedge a portion of its exposure to future electricity and fuel commodity price risk.

At December 31, 2000, our domestic merchant energy business has several contracts to sell electricity for each calendar year beginning 2003 through 2010 at fixed prices to hedge a portion of the forecasted sales of electricity by our domestic merchant energy plants during these periods. At December 31, 2000, we recorded deferred hedge losses of $58 million in "Other deferred charges" in our Consolidated Balance Sheets. We will reclassify these deferred hedge losses to "Accumulated other comprehensive income" when we adopt SFAS No. 133 in 2001.

Regulated Electric Business

The standard offer service arrangement between BGE and Constellation Power Source ends June 30, 2003. Under the Restructuring Order, effective July 1, 2000, BGE's residential rates are frozen for a six-year period and its commercial and industrial rates are frozen for four to six years. As a result, BGE will be subject to commodity price risk beginning July 1, 2003 upon termination of the existing standard offer arrangement. In accordance with the Restructuring Order, BGE will competitively bid the standard offer service supply for the remaining period of the rate freeze subsequent to June 30, 2003. During the remaining period of BGE's rate freeze, BGE will be unable to pass through to its customers any increase in the market price of electricity it must purchase to meet the standard offer service load. Our regulated electric business is evaluating various alternatives to minimize the market risk after June 30, 2003.

Regulated Gas Business

We use basis swaps in the winter months (November through March) to hedge our price risk associated with natural gas purchases under our market based rates incentive mechanism. We also use fixed-to-floating and floating-to-fixed swaps to hedge our price risk associated with our off-system gas sales. The fixed portion represents a specific dollar amount that we will pay or receive and the floating portion represents a fluctuating amount based on a published index that we will receive or pay. Our regulated gas business internal guidelines do not permit the use of swap agreements for any purpose other than to hedge price risk.

BGE's off-system gas sales activities represent trading activities under EITF 98-10. Accordingly, we use mark-to-market accounting to record these transactions. The trading activities relating to our off-system gas sales were not material at December 31, 2000 and 1999.

We defer, as unrealized gains or losses, the changes in fair value of the swap agreements under the market based rates incentive mechanism and the customers' portion of off-system gas sales in our Consolidated Balance Sheets. When amounts are paid under the agreements, we report the payments as gas costs in our Consolidated Statements of Income. We report the changes in fair value for the shareholders' portion of off-system gas sales in earnings as a component of gas costs.

Credit Risk

We are exposed to credit risk, primarily through Constellation Power Source. Credit risk is the loss that may result from a counterparty's nonperformance. Constellation Power Source uses credit policies to control its credit risk, including utilizing an established credit approval process, monitoring counterparty limits, employing credit mitigation measures such as margin, collateral or prepayment arrangements, and using master netting agreements. However, due to the possibility of extreme volatility in the prices of electricity commodities and derivatives, the market value of contractual positions with individual counterparties could exceed established credit limits or collateral provided by those counterparties. If such a counterparty were then to fail to perform its obligations under its contract (for example, fail to deliver the electricity Constellation Power Source had contracted for), Constellation Power Source could sustain a loss that could have a material impact on our financial results.

Taxes

We summarize our income taxes in our Consolidated Statements of Income Taxes on page 52. As you read this section, it may be helpful to refer to those statements.

Income Tax Expense

We have two categories of income taxes in our Consolidated Statements of Income—current and deferred. We describe each of these below.

Our current income tax expense consists solely of regular tax less applicable tax credits.

Our deferred income tax expense is equal to the changes in the net deferred income tax liability, excluding amounts charged or credited to common shareholders' equity. Our deferred income tax expense is increased or reduced for changes to the "Income taxes recoverable through future rates (net)" regulatory asset (described later in this note) during the year.

Investment Tax Credits

We have deferred the investment tax credit associated with our regulated utility business and assets previously held by our regulated utility business in our Consolidated Balance Sheets. The investment tax credit is amortized evenly to income over the life of each property. We reduce income tax expense in our Consolidated Statements of Income for the investment tax credit and other tax credits associated with our nonregulated businesses, other than leveraged leases.

Deferred Income Tax Assets and Liabilities

We must report some of our revenues and expenses differently for our financial statements than we do for income tax purposes. The tax effects of the differences in these items are reported as deferred income tax assets or liabilities in our Consolidated Balance Sheets. We measure the assets and liabilities using income tax rates that are currently in effect.

A portion of our total deferred income tax liability relates to our regulated utility business, but has not been reflected in the rates we charge our customers. We refer to this portion of the liability as "Income taxes recoverable through future rates (net)." We have recorded that portion of the net liability as a regulatory asset in our Consolidated Balance Sheets. We discuss this further in Note 5 on page 64.

State and Local Taxes

As discussed in Note 4 on page 62, tax legislation has made comprehensive changes to the state and local taxation of electric and gas utilities. State and local income taxes are included in "Income taxes" in our Consolidated Statements of Income.

Through December 31, 1999, we paid Maryland public service company franchise tax on our utility revenue from sales in Maryland instead of state income tax. We include the franchise tax in "Taxes other than income taxes" in our Consolidated Statements of Income.

Cash and Cash Equivalents

For the purpose of reporting our cash flows, we define cash equivalents as highly liquid investments that mature in three months or less.

At December 31, 2000, $112.5 million of the cash balance included in our Consolidated Balance Sheets was restricted under certain collateral arrangements for our power marketing operation.

Inventory

We report the majority of our fuel stocks and materials and supplies at average cost.

Real Estate Projects and Investments

In Note 3 on page 61, we summarize the real estate projects and investments that are in our Consolidated Balance Sheets. The projects and investments consist of:

- land under development in the Baltimore-Washington corridor,
- a mixed-use planned-unit development, and
- an equity interest in Corporate Office Properties Trust, a real estate investment trust.

The costs incurred to acquire and develop properties are included as part of the cost of the properties.

Financial Investments and Trading Securities

In Note 3 on page 61, we summarize the financial investments that are in our Consolidated Balance Sheets.

SFAS No. 115, *Accounting for Certain Investments in Debt and Equity Securities,* applies particular requirements to some of our investments in debt and equity securities. We report those investments at fair value, and we use specific identification to determine their cost for computing realized gains or losses. We classify these investments as either trading securities or available-for-sale securities, which we describe separately on page 57. We report investments that are not covered by SFAS No. 115 at their cost.

Trading Securities
Our other nonregulated businesses classify some of their investments in marketable equity securities and financial limited partnerships as trading securities. We include any unrealized gains or losses on these securities in "Nonregulated revenues" in our Consolidated Statements of Income.

Available-for-Sale Securities
We classify our investments in the nuclear decommissioning trust fund as available-for-sale securities. We include any unrealized gains or losses on the trust assets as a change in the decommissioning reserve. We describe the nuclear decommissioning trust and the reserve under the heading "Decommissioning Costs" later in this note on page 58.

In addition, our other nonregulated businesses classify some of their investments in marketable equity securities as available-for-sale securities. We include any unrealized gains or losses on these securities in "Accumulated other comprehensive income" in our Consolidated Statements of Common Shareholders' Equity on page 49 and in the Consolidated Statements of Capitalization on page 51.

Evaluation of Assets for Impairment and Other Than Temporary Decline in Value
SFAS No. 121, *Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of,* applies particular requirements to some of our assets that have long lives (some examples are generating property and equipment and real estate). We determine if those assets are impaired by comparing their undiscounted expected future cash flows to their carrying amount in our accounting records. We recognize an impairment loss if the undiscounted expected future cash flows are less than the carrying amount of the asset. Additionally, we evaluate our equity-method investments to determine whether our investments have a loss in value that is considered other than a temporary decline in value. We use our best estimates to determine if there has been an impairment or decline in value other than temporary and consider various factors including forward price curves for energy, fuel costs, and operating costs. However, it is possible that future market prices and project costs could vary from those used in evaluating our long-lived assets and investments, and the impact of such variations could be material.

Property, Plant and Equipment, Depreciation, Amortization, and Decommissioning
We report our property, plant and equipment at its original cost, unless impaired under the provisions of SFAS No. 121. Our original costs include:

- material and labor,
- contractor costs, and
- construction overhead costs and financing costs (where applicable).

We charge retired or otherwise disposed of property, plant and equipment that was depreciated under the composite, straight-line method to accumulated depreciation. This includes regulated utility property, plant and equipment and nonregulated generating assets previously owned by the regulated utility. When any other property, plant and equipment is retired, or otherwise disposed of, we reduce the property, plant and equipment balances and related accumulated depreciation and amortization amounts, and recognize any gain or loss in our Consolidated Statements of Income.

The costs of maintenance and certain replacements are charged to "Operating expenses" in our Consolidated Statements of Income as incurred.

We own an undivided interest in the Keystone and Conemaugh electric generating plants in Western Pennsylvania, as well as in the transmission line that transports the plants' output to the joint owners' service territories. Our ownership interests in these plants are 20.99% in Keystone and 10.56% in Conemaugh. These ownership interests represented a net investment of $143 million at December 31, 2000 and $156 million at December 31, 1999.

The "Nonregulated generation property, plant and equipment" in our Consolidated Balance Sheets includes nonregulated generation construction work in progress of $901.8 million at December 31, 2000 and $97.7 million at December 31, 1999.

Depreciation Expense
We compute depreciation over the estimated useful lives of depreciable property using the:

- composite, straight-line rates (approved by the Maryland PSC for our regulated utility business) applied to the average investment in classes of depreciable property based on an average rate of approximately three percent per year,
- units of production method for certain nonregulated generation facilities, or
- straight-line method.

Amortization Expense
Amortization is an accounting process of reducing an amount in our Consolidated Balance Sheets evenly over a period of time. When we reduce amounts in our Consolidated Balance Sheets, we increase amortization expense in our Consolidated Statements of Income. An amount is considered fully amortized when it has been reduced to zero.

We are required, along with other domestic utilities, by the Energy Policy Act of 1992 to make contributions to a fund for decommissioning and decontaminating the Department of Energy's uranium enrichment facilities. The contributions are generally payable over 15 years with escalation for inflation and are based upon the proportionate amount of uranium enriched by the Department of Energy for each utility. We amortize the deferred costs of decommissioning and decontaminating the Department of Energy's uranium enrichment facilities.

We also amortize nuclear fuel based on the energy produced over the life of the fuel including the quarterly fees we pay to the Department of Energy for the future disposal of spent nuclear fuel. These fees are based on the kilowatt-hours of electricity sold. We report the amortization expense for nuclear fuel in "Operating expenses" in our Consolidated Statements of Income.

Decommissioning Costs

We must accumulate a reserve for the costs that we expect to incur in the future to decommission the radioactive portion of Calvert Cliffs. We do this based on a sinking fund methodology. The Maryland PSC authorized us to include in the rates that we charge our customers decommissioning expense based on a facility-specific cost estimate so we can accumulate a decommissioning reserve of $521 million in 1993 dollars by the end of Calvert Cliffs' service life, adjusted to reflect expected inflation. We have reported the decommissioning reserve in "Accumulated depreciation" in our Consolidated Balance Sheets. The total reserve was $310.1 million at December 31, 2000 and $287.5 million at December 31, 1999. Our contributions to the nuclear decommissioning trust funds were $13.2 million for 2000 and $17.6 million for 1999 and 1998.

To fund the costs we expect to incur to decommission the plant, we established an external decommissioning trust in accordance with Nuclear Regulatory Commission (NRC) regulations. We report the assets in the trust in "Nuclear decommissioning trust fund" in our Consolidated Balance Sheets. The NRC requires utilities to provide financial assurance that they will accumulate sufficient funds to pay for the cost of nuclear decommissioning based upon either a generic NRC formula or a facility-specific decommissioning cost estimate. We use the facility-specific cost estimate for funding these costs and providing the required financial assurance.

Capitalized Interest and Allowance for Funds Used During Construction

Capitalized Interest

With the issuance of the Restructuring Order, we ceased accruing AFC (discussed below) for electric generation-related construction projects.

Our nonregulated businesses capitalize interest costs under SFAS No. 34, *Capitalizing Interest Costs,* for costs incurred to finance our power projects and real estate developed for internal use.

Allowance for Funds Used During Construction (AFC)

We finance regulated utility construction projects with borrowed funds and equity funds. We are allowed by the Maryland PSC to record the costs of these funds as part of the cost of construction projects in our Consolidated Balance Sheets. We do this through the AFC, which we calculate using a rate authorized by the Maryland PSC. We bill our customers for the AFC plus a return after the utility property is placed in service.

The AFC rates are 9.40% for electric plant, 8.61% for gas plant, and 9.19% for common plant. We compound AFC annually.

Long-Term Debt

We defer (include as an asset or liability in our Consolidated Balance Sheets and exclude from our Consolidated Statements of Income) all costs related to the issuance of long-term debt. These costs include underwriters' commissions, discounts or premiums, and other costs such as legal, accounting, and regulatory fees, and printing costs. We amortize these costs over the life of the debt.

When we incur gains or losses on debt that we retire prior to maturity in our regulated utility business, we amortize those gains or losses over the remaining original life of the debt.

When we incur gains or losses on debt that we retire prior to maturity in our nonregulated businesses, we record these gains or losses as an extraordinary item, if material.

Use of Accounting Estimates

Management makes estimates and assumptions when preparing financial statements under accounting principles generally accepted in the United States of America. These estimates and assumptions affect various matters, including:

- our reported amounts of assets and liabilities in our Consolidated Balance Sheets at the dates of the financial statements,
- our disclosure of contingent assets and liabilities at the dates of the financial statements, and
- our reported amounts of revenues and expenses in our Consolidated Statements of Income during the reporting periods.

These estimates involve judgments with respect to, among other things, future economic factors that are difficult to predict and are beyond management's control. As a result, actual amounts could differ from these estimates.

Reclassifications
We have reclassified certain prior-year amounts for comparative purposes. These reclassifications did not affect consolidated net income for the years presented.

Accounting Standards Issued
In June 1998, the FASB issued SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities.* SFAS No. 133 establishes the accounting and disclosure standards for derivative financial instruments and hedging activities. In July 1999, the FASB issued SFAS No. 137 that delayed the effective date for SFAS No. 133 by one year. Therefore, we must adopt the provisions of SFAS No. 133 in our financial statements for the quarter ended March 31, 2001. In June 2000, the FASB issued SFAS No. 138, *Accounting for Certain Derivative Instruments and Certain Hedging Activities,* that amended certain provisions of SFAS No. 133 and addressed a limited number of implementation issues related to SFAS No. 133.

These statements require that we recognize all derivatives on the balance sheet at fair value. Changes in the value of derivatives that are not hedges must be recorded in earnings. We expect to use derivatives to hedge the risk of variations in future cash flows from forecasted purchases and sales of electricity. Changes in the value of these derivatives will be recognized in other comprehensive income until the forecasted transaction occurs. The ineffective portion of the change in fair value of a derivative being used as a hedge will be immediately recognized in earnings.

The cumulative effect on earnings of adopting these statements is not material. As of December 31, 2000, we entered into certain forward sales of electricity that were designated as cash flow hedges of forecasted transactions. We will record a reduction in other comprehensive income of approximately $35 million after-tax to reflect these cash flow hedges in accordance with these statements.

2 Information by Operating Segment

In 1999, we reported three operating business segments—Electric, Gas, and Energy Services. In response to the deregulation of electric generation, we realigned our organization and combined our wholesale power marketing operation with our domestic plant development and operation activities to form a domestic merchant energy business.

In 2000, we revised our operating segments to reflect the realignments of our organization. Our new reportable operating segments are — Domestic Merchant Energy, Regulated Electric, and Regulated Gas:

- Our nonregulated domestic merchant energy business:
  - provides power marketing and risk management services,
  - develops, owns, and operates domestic power projects, and
  - provides nuclear consulting services.
- Our regulated electric business purchases, distributes and sells electricity, and
- Our regulated gas business purchases, transports, and sells natural gas.

We have restated certain prior period information for comparative purposes based on our new reportable operating segments.

Effective July 1, 2000, the financial results of the electric generation portion of our business are included in the domestic merchant energy business segment. Prior to that date, the financial results of electric generation are included in our regulated electric business.

Our remaining nonregulated businesses:

- develop, own, and operate international power projects in Latin America,
- provide energy products and services,
- sell and service electric and gas appliances, and heating and air conditioning systems, engage in home improvements, and sell natural gas through mass marketing efforts,
- provide cooling services,
- engage in financial investments, and
- develop, own and manage real estate and senior-living facilities.

These reportable segments are strategic businesses based principally upon regulations, products, and services that require different technology and marketing strategies. We evaluate the performance of these segments based on net income. We account for intersegment revenues using market prices. A summary of information by operating segment is shown on page 60.

	Domestic Merchant Energy Business	Regulated Electric Business	Regulated Gas Business	Other Nonregulated Businesses	Unallocated Corporate Items and Eliminations	Consolidated
			(In millions)			
2000						
Unaffiliated revenues	**$ 415.4**	**$2,134.7**	**$ 603.8**	**$ 724.6**	**$ —**	**$3,878.5**
Intersegment revenues	**576.6**	**0.5**	**7.8**	**15.7**	**(600.6)**	**—**
Total revenues	**992.0**	**2,135.2**	**611.6**	**740.3**	**(600.6)**	**3,878.5**
Depreciation and amortization	**80.9**	**319.9**	**46.2**	**23.0**	**—**	**470.0**
Equity in income of equity-method investees (a)	**—**	**2.4**	**—**	**—**	**—**	**2.4**
Net interest expense	**31.0**	**157.0**	**25.5**	**53.1**	**(8.4)**	**258.2**
Income tax expense	**122.5**	**72.2**	**21.9**	**13.5**	**—**	**230.1**
Net income (b)	**206.8**	**102.3**	**30.6**	**5.6**	**—**	**345.3**
Segment assets	**6,753.3**	**3,453.4**	**1,028.8**	**1,299.5**	**(150.4)**	**12,384.6**
Capital expenditures	**811.2**	**290.3**	**59.7**	**19.3**	**—**	**1,180.5**
1999						
Unaffiliated revenues	$ 212.9	$2,258.8	$ 476.5	$ 838.0	$ —	$3,786.2
Intersegment revenues	—	1.2	11.6	20.1	(32.9)	—
Total revenues	212.9	2,260.0	488.1	858.1	(32.9)	3,786.2
Depreciation and amortization	5.0	376.4	44.9	23.5	—	449.8
Equity in income of equity-method investees (a)	—	5.1	—	—	—	5.1
Net interest expense	—	162.4	24.4	56.1	(1.4)	241.5
Income tax expense (benefit)	29.4	149.2	18.1	(10.3)	—	186.4
Extraordinary loss	—	66.3	—	—	—	66.3
Net income (loss) (c)	52.4	198.8	33.0	(24.1)	—	260.1
Segment assets	1,206.1	6,312.6	915.3	1,231.3	18.5	9,683.8
Capital expenditures	260.9	366.8	69.2	17.3	—	714.2
1998						
Unaffiliated revenues	$ 147.3	$2,219.2	$ 449.4	$ 570.5	$ —	$3,386.4
Intersegment revenues	—	1.6	1.7	12.5	(15.8)	—
Total revenues	147.3	2,220.8	451.1	583.0	(15.8)	3,386.4
Depreciation and amortization	3.0	313.0	45.4	13.9	0.2	375.5
Equity in income of equity-method investees (a)	—	5.0	—	—	—	5.0
Net interest expense	—	164.9	23.6	50.7	(0.4)	238.8
Income tax expense (benefit)	28.6	146.6	13.4	(10.9)	—	177.7
Net income (loss) (d)	53.1	259.6	26.1	(32.9)	—	305.9
Segment assets	885.3	6,342.8	934.6	1,275.2	(3.8)	9,434.1
Capital expenditures	317.5	339.5	65.5	7.7	—	730.2

(a) Our domestic merchant energy business records its equity in the income of equity method investees in unaffiliated revenues.

(b) Our regulated electric business recorded expense of $4.2 million related to employees that elected to participate in a Targeted Voluntary Special Early Retirement Program. In addition, our domestic merchant energy business recorded a $15.0 million deregulation transition cost incurred by our power marketing operation.

(c) Our regulated electric business recorded expense of $4.9 million related to Hurricane Floyd. Our domestic merchant energy business recorded $14.2 million for the write-off of two geothermal power plants. Our Latin American operation recorded $4.5 million for the write-down to reflect the fair value of our investment in a power project in Bolivia. Our financial investments operation recorded $16.0 million for the write-down of its investment in Capital Re stock to reflect the market value of this investment. Our real estate and senior-living facilities operation recorded $5.8 million for the write-down of certain senior-living facilities.

(d) Our domestic merchant energy business recorded $10.4 million for its share of earnings in a partnership. Our energy products and services operation recorded $5.5 million for the write-off of an energy services investment. Our real estate and senior-living facilities operation recorded $15.4 million for the write-down of a real estate project.

3 Investments

Real Estate Projects and Investments

Real estate projects and investments held by Constellation Real Estate Group (CREG), consist of the following:

At December 31,	**2000**	1999
	(In millions)	
Properties under development	**$165.1**	$197.8
Rental and operating properties (net of accumulated depreciation)	**12.7**	9.2
Equity interest in real estate investments	**112.5**	103.1
Total real estate projects and investments	**$290.3**	$310.1

In 1999, CREG sold Church Street Station—an entertainment, dining, and retail complex in Orlando, Florida—for $11.5 million, the approximate book value of the complex.

In 1998, CREG entered into an agreement with Corporate Office Properties Trust (COPT), a real estate investment trust based in Philadelphia, under which COPT assumed approximately $62 million of CREG's outstanding debt, paid CREG approximately $22.8 million in cash, and issued to CREG approximately 7.0 million common shares representing a 41.9% equity interest in COPT and 985,000 convertible preferred shares. Each convertible preferred share yields 5.5% per year, and is convertible after two years into 1.8748 common shares.

In exchange, COPT received 14 operating properties and two properties under development from CREG as well as certain other assets, options, and first refusal rights. These options and first refusal rights are related to approximately 91 acres of identified properties which are adjacent to operating properties acquired by COPT. At December 31, 2000, 30 acres remain under these options and first refusal rights with terms that range from one to three years.

In September 2000, CREG converted 984,307 preferred shares of COPT into approximately 1.8 million common shares of COPT.

Power Projects

Investments in power projects held by our domestic merchant energy business consist of the following:

At December 31,	**2000**	1999
	(In millions)	
East	**$ 86.3**	$ 85.1
West	**419.8**	416.5
Total domestic power projects	**$506.1**	$501.6

Our Domestic-West power projects include investments of $297.9 million in 2000 and $301.8 million in 1999 that sell electricity in California under power purchase agreements called "Interim Standard Offer No. 4" agreements. We discuss these projects further in Note 10 on page 74.

In 1999, our domestic generation operation recorded a $14.2 million after-tax write-off of two geothermal power projects. These write-offs occurred because the expected future cash flows from the projects are less than the investment in the projects. For the first project, this resulted from the inability to restructure certain project agreements. For the second project, the water temperature of the geothermal resource used by one of the plants for production declined.

In 1998, our domestic generation operation recorded $10.4 million after-tax gain for its share of earnings in a partnership. The partnership recognized a gain on the sale of its ownership interest in a power sales contract.

Our Latin American operation held power projects of $11.4 million at December 31, 2000 and $12.3 million at December 31, 1999.

In 1999, our Latin American operation recorded a $4.5 million after-tax write-down to reflect the fair value of our investment in a generating company in Bolivia as a result of our international exit strategy.

Financial Investments

Financial investments held by Constellation Investments, Inc. consist of the following:

At December 31,	**2000**	1999
	(In millions)	
Marketable equity securities	**$105.9**	$ 84.2
Financial limited partnerships	**32.7**	35.8
Leveraged leases	**22.4**	25.4
Total financial investments	**$161.0**	$145.4

In 1999, our financial investments operation announced that it would exchange its shares of common stock in Capital Re, an insurance company, for common stock of ACE Limited (ACE), another insurance company, as part of a business combination whereby ACE would acquire all of the outstanding capital stock of Capital Re. As a result, our financial investments operation wrote-down its $94.2 million investment in Capital Re stock by $16.0 million after-tax to reflect the closing price of the business combination.

Investments Classified as Available-for-Sale

We classify our investments in the nuclear decommissioning trust fund as available-for-sale. In addition, we classify some of our other nonregulated businesses' marketable equity securities (shown above) as available-for-sale. This means we do not expect to hold them to maturity and we do not consider them trading securities.

We show the fair values, gross unrealized gains and losses, and amortized cost bases for all of our available-for-sale securities, in the tables on page 62.

At December 31, 2000	Amortized Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
		(In millions)		
Marketable equity securities	**$171.8**	**$68.9**	**$(2.2)**	**$238.5**
Corporate debt and U.S. Government agency	**26.1**	**0.1**	**(0.1)**	**26.1**
State municipal bonds	**61.3**	**2.3**	**(0.4)**	**63.2**
Totals	**$259.2**	**$71.3**	**$(2.7)**	**$327.8**

At December 31, 1999	Amortized Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
		(In millions)		
Marketable equity securities	$167.1	$42.8	$(2.1)	$207.8
Corporate debt and U.S. Government agency	14.4	—	—	14.4
State municipal bonds	74.2	—	(0.8)	73.4
Totals	$255.7	$42.8	$(2.9)	$295.6

The preceding tables include $34.7 million in 2000 and $40.5 million in 1999 of unrealized net gains associated with the nuclear decommissioning trust fund which are reflected as a change in the nuclear decommissioning trust fund on the Consolidated Balance Sheets.

Gross and net realized gains and losses on available-for-sale securities were as follows:

	2000	1999	1998
		(In millions)	
Gross realized gains	**$54.5**	$ 11.7	$4.2
Gross realized losses	**(8.0)**	(38.8)	(0.7)
Net realized gains (losses)	**$46.5**	$(27.1)	$3.5

The Corporate debt securities, U.S. Government agency obligations, and state municipal bonds mature on the following schedule:

At December 31, 2000	Amount
	(In millions)
Less than 1 year	$ 0.9
1-5 years	41.9
5-10 years	23.7
More than 10 years	22.8
Total maturities of debt securities	$89.3

4 Rate Matters and Accounting Impacts of Deregulation

On April 8, 1999, Maryland enacted the Electric Customer Choice and Competition Act of 1999 (the "Act") and accompanying tax legislation that significantly restructured Maryland's electric utility industry and modified the industry's tax structure. In the Restructuring Order discussed below, the Maryland PSC addressed the major provisions of the Act.

The tax legislation made comprehensive changes to the state and local taxation of electric and gas utilities. Effective January 1, 2000, the Maryland public service franchise tax was altered to generally include a tax equal to .062 cents on each kilowatt-hour of electricity and .402 cents on each therm of natural gas delivered for final consumption in Maryland. The Maryland 2% franchise tax on electric and natural gas utilities continues to apply to transmission and distribution revenue. Additionally, all electric and natural gas utility results are subject to the Maryland corporate income tax.

Beginning July 1, 2000, the tax legislation also provides for a two-year phase-in of a 50% reduction in the local personal property taxes on machinery and equipment used to generate electricity for resale and a 60% corporate income tax credit for real property taxes paid on those facilities.

On November 10, 1999, the Maryland PSC issued a Restructuring Order that resolved the major issues surrounding electric restructuring, accelerated the timetable for customer choice, and addressed the major provisions of the Act. The Restructuring Order also resolved the electric restructuring proceeding (transition costs, customer price protections, and unbundled rates for electric services) and a petition filed in September 1998 by the Office of People's Counsel (OPC) to lower our electric base rates. The major provisions of the Restructuring Order are:

- All customers, except a few commercial and industrial companies that have signed contracts with BGE, can choose their electric energy supplier beginning July 1, 2000. BGE will provide a standard offer service for customers that do not select an alternative supplier. In either case, BGE will continue to deliver electricity to all customers in areas traditionally served by BGE.
- BGE's electric base rates were frozen through June 30, 2000.
- BGE reduced residential base rates by approximately 6.5%, on average about $54 million a year, beginning July 1, 2000. These rates will not change before July 2006.
- Commercial and industrial customers have up to four service options that will fix electric energy rates and transition charges for a period that generally ranges from four to six years.
- BGE's electric fuel rate clause was discontinued effective July 1, 2000.
- Electric delivery service rates are frozen for a four-year period for commercial and industrial customers. The generation and transmission components of rates are frozen for different time periods depending on the service options selected by those customers.

- BGE will recover $528 million after-tax of its potentially stranded investments and utility restructuring costs through a competitive transition charge on customers' bills. Residential customers will pay this charge for six years. Commercial and industrial customers will pay in a lump sum or over the four to six-year period, depending on the service option selected by each customer.
- Generation-related regulatory assets and nuclear decommissioning costs are included in delivery service rates effective July 1, 2000 and will be recovered on a basis approximating their amortization schedules prior to July 1, 2000.
- Effective July 1, 2000, BGE unbundled rates to show separate components for delivery service, competitive transition charges, standard offer services (generation), transmission, universal service, and taxes.
- Effective July 1, 2000, BGE transferred, at book value, its ten Maryland-based fossil and nuclear power plants and its partial ownership interest in two coal plants and a hydroelectric plant in Pennsylvania to nonregulated subsidiaries of Constellation Energy.
- BGE reduced its generation assets by $150 million pre-tax during the period July 1, 1999 - June 30, 2000 to mitigate a portion of BGE's potentially stranded investments.
- Universal service is being provided for low-income customers without increasing their bills. BGE will provide its share of a statewide fund totaling $34 million annually.

As discussed in Note 1 on page 53, EITF 97-4 requires that a company should cease applying SFAS No. 71 when either legislation is passed or a regulatory body issues an order that contains sufficient detail to determine how the transition plan will affect the deregulated portion of the business. Additionally, a company would continue to recognize regulatory assets and liabilities in the Consolidated Balance Sheets to the extent that the transition plan provides for their recovery.

We believe that the Restructuring Order provided sufficient details of the transition plan to competition for BGE's electric generation business to require BGE to discontinue the application of SFAS No. 71 for that portion of its business. Accordingly, in the fourth quarter of 1999, we adopted the provisions of SFAS No. 101 and EITF 97-4 for BGE's electric generation business.

SFAS No. 101 requires the elimination of the effects of rate regulation that have been recognized as regulatory assets and liabilities pursuant to SFAS No. 71. However, EITF 97-4 requires that regulatory assets and liabilities that will be recovered in the regulated portion of the business continue to be classified as regulatory assets and liabilities. The Restructuring Order provided for the creation of a single, new generation-related regulatory asset to be recovered through BGE's regulated transmission and distribution business. We discuss this further in Note 5 on page 64.

Pursuant to SFAS No. 101, the book value of property, plant, and equipment may not be adjusted unless those assets are impaired under the provisions of SFAS No. 121. The process we used in evaluating and measuring impairment under the provisions of SFAS No. 121 involved two steps. First, we compared the net book value of each generating plant to the estimated undiscounted future net operating cash flows from that plant. An electric generating plant was considered impaired when its undiscounted future net operating cash flows were less than its net book value. Second, we computed the fair value of each plant that is determined to be impaired based on the present value of that plant's estimated future net operating cash flows discounted using an interest rate that considers the risk of operating that facility in a competitive environment. To the extent that the net book value of each impaired electric generation plant exceeded its fair value, we recorded a write-down.

Under the Restructuring Order, BGE will recover $528 million after-tax of its potentially stranded investments and utility restructuring costs through the competitive transition charge component of its customer rates beginning July 1, 2000. This recovery mostly relates to the stranded costs associated with BGE's Calvert Cliffs Nuclear Power Plant, whose book value was substantially higher than its estimated fair value. However, Calvert Cliffs was not considered impaired under the provisions of SFAS No. 121 since its estimated future undiscounted cash flows exceeded its book value. Accordingly, BGE did not record any impairment write-down related to Calvert Cliffs. However, we recognized after-tax impairment losses totaling $115.8 million associated with certain of our fossil plants under the provisions of SFAS No. 121.

BGE had contracts to purchase electric capacity and energy that became uneconomic upon the deregulation of electric generation. Therefore, we recorded a $34.2 million after-tax charge based on the net present value of the excess of estimated contract costs over the market-based revenues to recover these costs over the remaining terms of the contracts. In addition, BGE had deferred certain energy conservation expenditures that would not be recovered through its transmission and distribution business under the Restructuring Order. Accordingly, we recorded a $10.3 million after-tax charge to eliminate the regulatory asset previously established for these deferred expenditures.

At December 31, 1999, the total charge for BGE's electric generating plants that were impaired, losses on uneconomic purchased capacity and energy contracts, and deferred energy conservation expenditures was approximately $160.3 million after-tax.

BGE recorded approximately $94.0 million of the $160.3 million on its balance sheet. This consisted of a $150.0 million regulatory asset of its regulated transmission and distribution business, net of approximately $56.0 million of associated deferred income taxes. The regulatory asset was amortized as it was recovered from ratepayers through June 30, 2000. This accomplished the $150 million reduction of its generation plants required by the Restructuring Order.

We recorded an after-tax, extraordinary charge against earnings for approximately $66.3 million related to the remaining portion of the $160.3 million described above that was not recovered under the Restructuring Order.

5 Regulatory Assets (net)

As discussed in Note 1 on page 53, the Maryland PSC provides the final determination of the rates we charge our customers for our regulated businesses. Generally, we use the same accounting policies and practices used by nonregulated companies for financial reporting under accounting principles generally accepted in the United States of America. However, sometimes the Maryland PSC orders an accounting treatment different from that used by nonregulated companies to determine the rates we charge our customers. When this happens, we must defer certain utility expenses and income in our Consolidated Balance Sheets as regulatory assets and liabilities. We then record them in our Consolidated Statements of Income (using amortization) when we include them in the rates we charge our customers.

We summarize regulatory assets and liabilities in the following table, and we discuss each of them separately below.

At December 31,	**2000**	1999
	(In millions)	
Generation plant reduction recoverable in current rates	**$ —**	$ 75.0
Electric generation-related regulatory asset	**267.8**	286.6
Income taxes recoverable through future rates (net)	**101.2**	110.4
Deferred postretirement and postemployment benefit costs	**38.7**	41.9
Deferred conservation expenditures	**5.8**	12.9
Deferred environmental costs	**28.8**	31.3
Deferred fuel costs (net)	**71.1**	73.8
Other (net)	**1.5**	5.5
Total regulatory assets (net)	**$514.9**	$637.4

Generation Plant Reduction Recoverable in Current Rates

Under the Restructuring Order, BGE recorded a reduction to its generation plant of $150 million which it recovered through its rates between July 1, 1999 and June 30, 2000. In 1999, BGE recorded a $150 million regulatory asset for the required generation plant reduction that was amortized as it was recovered from ratepayers through June 30, 2000.

Electric Generation-Related Regulatory Asset

With the issuance of the Restructuring Order, BGE no longer met the requirements for the application of SFAS No. 71 for the electric generation portion of its business. In accordance with SFAS No. 101 and EITF 97-4, all individual generation-related regulatory assets and liabilities must be eliminated from our balance sheet unless these regulatory assets and liabilities will be recovered in the regulated portion of the business. Pursuant to the Restructuring Order, BGE wrote-off all of its individual, generation-related regulatory assets and liabilities. BGE established a single, new generation-related regulatory asset for amounts to be collected through its regulated transmission and distribution business. The new regulatory asset is being amortized on a basis that approximates the pre-existing individual regulatory asset amortization schedules.

Income Taxes Recoverable Through Future Rates (net)

As described in Note 1 on page 56, income taxes recoverable through future rates are the portion of our net deferred income tax liability that is applicable to our regulated utility business, but has not been reflected in the rates we charge our customers. These income taxes represent the tax effect of temporary differences in depreciation and the allowance for equity funds used during construction, offset by differences in deferred tax rates and deferred taxes on deferred investment tax credits. We amortize these amounts as the temporary differences reverse.

In 1999, we reclassified the electric generation-related portion of this net regulatory asset to the electric generation-related regulatory asset discussed earlier in this note.

Deferred Postretirement and Postemployment Benefit Costs

Deferred postretirement and postemployment benefit costs are the costs we recorded under SFAS No. 106 (for post-retirement benefits) and No. 112 (for postemployment benefits) in excess of the costs we included in the rates we charge our customers. We began amortizing these costs over a 15-year period in 1998. We discuss these costs further in Note 6 beginning on page 65.

In 1999, we reclassified the electric generation-related portion of this regulatory asset to the electric generation-related regulatory asset discussed earlier in this note.

Deferred Conservation Expenditures

Deferred conservation expenditures include two components:

- operations costs (labor, materials, and indirect costs) associated with conservation programs approved by the Maryland PSC, which we are amortizing over periods of four to five years in accordance with the Maryland PSC's orders, and
- revenues we collected from customers in 1996 in excess of our profit limit under the conservation surcharge.

In 1999, we wrote off a portion of the unamortized electric conservation expenditures that will not be recovered under the Restructuring Order as discussed in Note 4 on page 63.

Deferred Environmental Costs

Deferred environmental costs are the estimated costs of investigating and cleaning up contaminated sites we own. We discuss this further in Note 10 on page 71. We are amortizing $21.6 million of these costs (the amount we had incurred through October 1995) and $6.4 million of these costs (the amount we incurred from November 1995 through June 2000) over 10-year periods in accordance with Maryland PSC's orders.

Deferred Fuel Costs
As described in Note 1 on page 54, deferred fuel costs are the difference between our actual costs of electric fuel, net purchases and sales of electricity, and natural gas, and our fuel rate revenues collected from customers. We reduce deferred fuel costs as we collect them from or refund them to our customers.

We show our deferred fuel costs in the following table.

At December 31,	**2000**	1999
	(In millions)	
Electric	**$42.3**	$60.0
Gas	**28.8**	13.8
Deferred fuel costs (net)	**$71.1**	$73.8

Under the terms of the Restructuring Order, BGE's electric fuel rate clause was discontinued effective July 1, 2000. In September 2000, the Maryland PSC approved the collection of the $54.6 million accumulated difference between our actual costs of fuel and energy and the amounts collected from customers that were deferred under the electric fuel rate clause through June 30, 2000. We are collecting this accumulated difference from customers over the twelve-month period beginning October 2000.

6 Pension, Postretirement, Other Postemployment, and Employee Savings Plan Benefits

We offer pension, postretirement, other postemployment, and employee savings plan benefits. We describe each of these separately below.

Pension Benefits
We sponsor several defined benefit pension plans for our employees. A defined benefit plan specifies the amount of benefits a plan participant is to receive using information about the participant. Our employees do not contribute to these plans. Generally, we calculate the benefits under these plans based on age, years of service, and pay.

Sometimes we amend the plans retroactively. These retroactive plan amendments require us to recalculate benefits related to participants' past service. We amortize the change in the benefit costs from these plan amendments on a straight-line basis over the average remaining service period of active employees.

We fund the plans by contributing at least the minimum amount required under Internal Revenue Service regulations. We calculate the amount of funding using an actuarial method called the projected unit credit cost method. The assets in all of the plans at December 31, 2000 were mostly marketable equity and fixed income securities, and group annuity contracts.

In 1999, our Board of Directors approved the following amendments:

- eligible participants were allowed to choose between an enhanced version of the current benefit formula and a new pension equity plan (PEP) formula. Pension benefits for eligible employees hired after December 31, 1999 are based on a PEP formula, and
- pension and survivor benefits were increased for participants who retired prior to January 1, 1994 and for their surviving spouses.

The financial impacts of the amendments are included in the tables beginning on page 66.

Also during 1999, our Board of Directors approved a Targeted Voluntary Special Early Retirement Program (TVSERP) to provide enhanced early retirement benefits to certain eligible participants in targeted jobs that elected to retire on June 1, 2000. BGE recorded approximately $10.0 million ($7.6 million for pension and $2.4 million for postretirement benefit costs) for employees that elected to participate in the program. Of this amount, BGE recorded approximately $3.0 million on its balance sheet as a regulatory asset of its gas business. We will amortize this regulatory asset over a 5-year period as provided by the June 2000 Maryland PSC gas base rate order. The remaining $7.0 million related to BGE's electric business was charged to expense. The TVSERP charges are not included in the tables of net periodic pension and postretirement benefit costs included in this section on page 66.

Postretirement Benefits
We sponsor defined benefit postretirement health care and life insurance plans which cover nearly all BGE employees and certain employees of our subsidiaries. Generally, we calculate the benefits under these plans based on age, years of service, and pension benefit levels. We do not fund these plans.

For nearly all of the health care plans, retirees make contributions to cover a portion of the plan costs. Contributions for employees who retire after June 30, 1992 are calculated based on age and years of service. The amount of retiree contributions increases based on expected increases in medical costs. For the life insurance plan, retirees do not make contributions to cover a portion of the plan costs.

Effective January 1, 1993, we adopted SFAS No. 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions*. The adoption of that statement caused:

- a transition obligation, which we are amortizing over 20 years, and
- an increase in annual postretirement benefit costs.

For our nonregulated businesses, we expense all postretirement benefit costs. For our regulated utility business, we accounted for the increase in annual postretirement benefit costs under two Maryland PSC rate orders:

- in an April 1993 rate order, the Maryland PSC allowed us to expense one-half and defer, as a regulatory asset (see Note 5), the other half of the increase in annual postretirement benefit costs related to our regulated electric and gas businesses, and

- in a November 1995 rate order, the Maryland PSC allowed us to expense all of the increase in annual postretirement benefit costs related to our regulated gas business.

Beginning in 1998, the Maryland PSC authorized us to:

- expense all of the increase in annual postretirement benefit costs related to our regulated electric business, and
- amortize the regulatory asset for postretirement benefit costs related to our regulated electric and gas businesses over 15 years.

Obligations, Assets, and Funded Status

We show the change in the benefit obligations, plan assets, and funded status of the pension and postretirement benefit plans in the following tables:

	Pension Benefits		Postretirement Benefits	
	2000	1999	**2000**	1999
	(In millions)			
Change in benefit obligation				
Benefit obligation at January 1	**$1,016.7**	$1,031.3	**$358.7**	$383.1
Service cost	**25.4**	26.1	**7.7**	8.6
Interest cost	**73.1**	65.3	**26.6**	24.4
Plan participants' contributions	**—**	—	**2.8**	2.0
Actuarial (gain) loss	**0.8**	(93.0)	**40.9**	(34.2)
Plan amendments	**6.7**	44.6	**(41.1)**	(5.0)
TVSERP charge	**7.6**	—	**2.4**	—
Benefits paid	**(85.2)**	(57.6)	**(22.1)**	(20.2)
Benefit obligation at December 31	**$1,045.1**	$1,016.7	**$375.9**	$358.7

	Pension Benefits		Postretirement Benefits	
	2000	1999	**2000**	1999
	(In millions)			
Change in plan assets				
Fair value of plan assets at January 1	**$1,084.9**	$ 985.5	**$ —**	$ —
Actual return on plan assets	**3.7**	139.4	**—**	—
Employer contribution	**26.7**	17.6	**19.3**	18.2
Plan participants' contributions	**—**	—	**2.8**	2.0
Benefits paid	**(85.2)**	(57.6)	**(22.1)**	(20.2)
Fair value of plan assets at December 31	**$1,030.1**	$1,084.9	**$ —**	$ —

	Pension Benefits		Postretirement Benefits	
	2000	1999	**2000**	1999
	(In millions)			
Funded Status				
Funded Status at December 31	**$(15.0)**	$68.2	**$(375.9)**	$(358.7)
Unrecognized net actuarial (gain) loss	**49.2**	(27.2)	**61.4**	23.6
Unrecognized prior service cost	**59.2**	59.0	**(0.4)**	(0.1)
Unrecognized transition obligation	**—**	—	**94.8**	143.4
Unamortized net asset from adoption of SFAS No. 87	**(0.2)**	(0.5)	**—**	—
Prepaid (accrued) benefit cost	**$ 93.2**	$99.5	**$(220.1)**	$(191.8)

Net Periodic Benefit Cost

We show the components of net periodic pension benefit cost in the following table:

Year Ended December 31,	**2000**	1999	1998
	(In millions)		
Components of net periodic pension benefit cost			
Service cost	**$25.4**	$26.1	$21.6
Interest cost	**73.1**	65.3	63.0
Expected return on plan assets	**(83.6)**	(76.6)	(72.1)
Amortization of transition obligation	**(0.2)**	(0.2)	(0.2)
Amortization of prior service cost	**6.5**	2.5	2.5
Recognized net actuarial loss	**2.6**	10.1	5.6
Amount capitalized as construction cost	**(3.4)**	(4.2)	(3.8)
Net periodic pension benefit cost	**$20.4**	$23.0	$16.6

We show the components of net periodic postretirement benefit cost in the following table:

Year Ended December 31,	**2000**	1999	1998
	(In millions)		
Components of net periodic postretirement benefit cost			
Service cost	**$ 7.7**	$ 8.6	$ 6.6
Interest cost	**26.6**	24.4	23.4
Amortization of transition obligation	**7.9**	11.0	11.4
Recognized net actuarial loss	**3.1**	1.9	0.2
Amount capitalized as construction cost	**(10.8)**	(9.4)	(8.1)
Net periodic postretirement benefit cost	**$34.5**	$36.5	$33.5

Assumptions

We made the assumptions below to calculate our pension and postretirement benefit obligations.

At December 31,	Pension Benefits **2000**	Pension Benefits 1999	Postretirement Benefits **2000**	Postretirement Benefits 1999
Discount rate	**7.50%**	7.25%	**7.50%**	7.25%
Expected return on plan assets	**9.00**	9.00	**N/A**	N/A
Rate of compensation increase	**4.00**	4.00	**4.00**	4.00

We assumed the health care inflation rates to be:

- in 2000, 10.7% for Medicare-eligible retirees and 12.3% for retirees not covered by Medicare, and
- in 2001, 6.5% for Medicare-eligible retirees and 8.0% for retirees not covered by Medicare.

After 2001, we assumed both inflation rates will decrease by 0.5% annually to a rate of 5.5% in the years 2003 and 2006, respectively. After these dates, the inflation rate will remain at 5.5%.

A one-percent increase in the health care inflation rate from the assumed rates would increase the accumulated postretirement benefit obligation by approximately $51.7 million as of December 31, 2000 and would increase the combined service and interest costs of the postretirement benefit cost by approximately $5.5 million annually.

A one-percent decrease in the health care inflation rate from the assumed rates would decrease the accumulated postretirement benefit obligation by approximately $41.5 million as of December 31, 2000 and would decrease the combined service and interest costs of the postretirement benefit cost by approximately $4.4 million annually.

Other Postemployment Benefits

We provide the following postemployment benefits:

- health and life insurance benefits to our employees and certain employees of our subsidiaries who are found to be disabled under our Disability Insurance Plan, and
- income replacement payments for employees found to be disabled before November 1995 (payments for employees found to be disabled after that date are paid by an insurance company, and the cost is paid by employees).

The liability for these benefits totaled $46.7 million as of December 31, 2000 and $46.5 million as of December 31, 1999.

Effective December 31, 1993, we adopted SFAS No. 112, *Employers' Accounting for Postemployment Benefits*. We deferred, as a regulatory asset (see Note 5 on page 64), the postemployment benefit liability attributable to our regulated utility business as of December 31, 1993, consistent with the Maryland PSC's orders for postretirement benefits (described earlier in this note).

We began to amortize the regulatory asset over 15 years beginning in 1998. The Maryland PSC authorized us to reflect this change in our regulated electric and gas base rates to recover the higher costs in 1998.

We assumed the discount rate for other postemployment benefits to be 5.5% in 2000 and 1999.

Employee Savings Plan Benefits

We also sponsor a defined contribution savings plan that is offered to all eligible employees of Constellation Energy and certain employees of our subsidiaries. In a defined contribution plan, the benefits a participant is to receive result from regular contributions to a participant account. Under this plan, we make matching contributions to participant accounts. We made matching contributions to this plan of:

- $10.8 million in 2000,
- $10.4 million in 1999, and
- $10.1 million in 1998.

7 Short-Term Borrowings

Our short-term borrowings may include bank loans, commercial paper, and bank lines of credit. Short-term borrowings mature within one year from the date of issuance. We pay commitment fees to banks for providing us lines of credit. When we borrow under the lines of credit, we pay market interest rates.

Constellation Energy

Constellation Energy had commercial paper outstanding of $198.7 million at December 31, 2000 and $242.5 million at December 31, 1999.

Constellation Energy had unused committed bank lines of credit of $565.0 million at December 31, 2000 and $295.0 million at December 31, 1999 for short-term financial needs, including letters of credit. These agreements also support Constellation Energy's commercial paper program. Letters of credit issued under these facilities totaled $180.3 million at December 31, 2000 and $23.1 million at December 31, 1999. In addition, Constellation Energy had $116.9 million in letters of credit outstanding at December 31, 2000 that were issued under separate credit facilities.

The weighted-average effective interest rate for Constellation Energy's commercial paper were 6.31% for the year ended December 31, 2000 and 5.68% for 1999.

BGE

BGE had commercial paper outstanding of $32.1 million at December 31, 2000 and $129.0 million at December 31, 1999.

At December 31, 2000, BGE had unused committed bank lines of credit totaling $218.0 million supporting the commercial paper program compared to $183.0 million at December 31, 1999.

The weighted-average effective interest rates for BGE's commercial paper were 6.36% for the year ended December 31, 2000 and 5.25% for 1999.

Other Nonregulated Businesses

Our other nonregulated businesses had short-term borrowings outstanding of $12.8 million at December 31, 2000. The weighted-average effective interest rate for our other nonregulated businesses' short-term borrowings was 8.59% for the year ended December 31, 2000.

8 Long-Term Debt

Long-term debt matures in one year or more from the date of issuance. We summarize our long-term debt in the Consolidated Statements of Capitalization. As you read this section, it may be helpful to refer to those statements.

Constellation Energy

In 2000, Constellation Energy issued $1.0 billion in long-term debt. On April 4, 2000, we issued $300.0 million of 7⅞% Fixed Rate Notes, due April 1, 2005 and $200.0 million of Floating Rate Notes, due April 4, 2003. Interest on the floating rate notes is reset quarterly.

On June 21, 2000, we issued $300.0 million of Extendible Notes, due June 21, 2010. The interest rate on these notes resets quarterly. On June 21, 2001, the notes may be remarketed for an additional period or redeemed for a purchase price equal to 100% of their principal amount, plus accrued interest.

On October 19, 2000, we issued $200.0 million of Floating Rate Reset Notes, due March 15, 2002. We redeemed these notes on January 17, 2001 at par.

On January 17, 2001, we issued $400.0 million of Mandatorily Redeemable Floating Rate Notes, due January 17, 2002. These notes are mandatorily redeemable at a purchase price equal to 100% of their principal amount, plus accrued interest, at least five days prior to the separation of our domestic merchant energy business from our remaining businesses.

In connection with the initiative to separate our businesses, Constellation Energy expects to redeem all of its outstanding debt at or prior to the separation. The redemption will occur through a combination of open market purchases, tender offers, and redemption calls. We expect to fund this redemption with short-term debt or other credit facilities, and to refinance this debt longer term after the separation.

BGE

BGE's First Refunding Mortgage Bonds

BGE's first refunding mortgage bonds are secured by a mortgage lien on all of its assets, including all utility properties and franchises and its subsidiary capital stock. Capital stock pledged under the mortgage is that of Safe Harbor Water Power Corporation and Constellation Enterprises, Inc. The generating assets BGE transferred to subsidiaries of Constellation Energy also remain subject to the lien of BGE's mortgage.

BGE is required to make an annual sinking fund payment each August 1 to the mortgage trustee. The amount of the payment is equal to 1% of the highest principal amount of bonds outstanding during the preceding 12 months. The trustee uses these funds to retire bonds from any series through repurchases or calls for early redemption. However, the trustee cannot call the following bonds for early redemption:

- 8⅜% Series, due 2001
- 7¼% Series, due 2002
- 6½% Series, due 2003
- 6⅛% Series, due 2003
- 5½% Series, due 2004
- 7½% Series, due 2007
- 6⅝% Series, due 2008

Holders of the Remarketed Floating Rate Series due September 1, 2006 have the option to require BGE to repurchase their bonds at face value on September 1 of each year. BGE is required to repurchase and retire at par any bonds that are not remarketed or purchased by the remarketing agent. BGE also has the option to redeem all or some of these bonds at face value each September 1.

BGE's Other Long-Term Debt

On July 1, 2000, BGE transferred $278.0 million of tax-exempt debt to our domestic merchant energy business related to the transferred assets. At December 31, 2000, BGE remains contingently liable for this debt.

On October 19, 2000, BGE issued $200.0 million of Floating Rate Reset Notes, due October 19, 2001. BGE can redeem these notes at 100% of the principal amount.

On December 20, 2000, BGE issued $173.0 million of 6.75% Remarketable and Redeemable Securities (ROARS) due December 15, 2012. The ROARS contain an option for the underwriters to remarket the ROARS on December 15, 2002. If the underwriters do not elect to remarket the ROARS on that date, then BGE must redeem the ROARS at 100% of the principal amount on December 15, 2002.

We show the weighted-average interest rates and maturity dates for BGE's fixed-rate medium-term notes outstanding at December 31, 2000 in the following table.

Series	Weighted-Average Interest Rate	Maturity Date
B	8.77%	2002-2006
C	7.97	2003
D	6.66	2001-2006
E	6.66	2006-2012
G	6.08	2002-2008

Some of the medium-term notes include a "put option." These put options allow the holders to sell their notes back to BGE on the put option dates at a price equal to 100% of the principal amount. The following is a summary of medium-term notes with put options.

Series E Notes	Principal	Put Option Dates
	(In millions)	
6.75%, due 2012	$60.0	June 2002 and 2007
6.75%, due 2012	$25.0	June 2004 and 2007
6.73%, due 2012	$25.0	June 2004 and 2007

BGE has a $25 million revolving credit agreement that is available through 2003. At December 31, 2000 and 1999, BGE did not have any borrowings under revolving credit agreements. The bank charges us commitment fees based on the daily average of the unborrowed amount, and we pay market interest rates on any borrowings. This agreement also supports BGE's commercial paper program, as described in Note 7 on page 67.

BGE Obligated Mandatorily Redeemable Trust Preferred Securities

On June 15, 1998, BGE Capital Trust I (Trust), a Delaware business trust established by BGE, issued 10,000,000 Trust Originated Preferred Securities (TOPrS) for $250 million ($25 liquidation amount per preferred security) with a distribution rate of 7.16%.

The Trust used the net proceeds from the issuance of the common securities and the preferred securities to purchase a series of 7.16% Deferrable Interest Subordinated Debentures due June 30, 2038 (debentures) from BGE in the aggregate principal amount of $257.7 million with the same terms as the TOPrS. The Trust must redeem the TOPrS at $25 per preferred security plus accrued but unpaid distributions when the debentures are paid at maturity or upon any earlier redemption. BGE has the option to redeem the debentures at any time on or after June 15, 2003 or at any time when certain tax or other events occur.

The interest paid on the debentures, which the Trust will use to make distributions on the TOPrS, is included in "Interest expense (net)" in the Consolidated Statements of Income and is deductible for income tax purposes.

BGE fully and unconditionally guarantees the TOPrS based on its various obligations relating to the trust agreement, indentures, debentures, and the preferred security guarantee agreement.

The debentures are the only assets of the Trust. The Trust is wholly owned by BGE because it owns all the common securities of the Trust that have general voting power.

For the payment of dividends and in the event of liquidation of BGE, the debentures are ranked prior to preference stock and common stock.

Other Nonregulated Businesses

Revolving Credit Agreement

ComfortLink has a $50 million unsecured revolving credit agreement that matures September 26, 2001. Under the terms of the agreement, ComfortLink has the option to obtain loans at various rates for terms up to nine months. ComfortLink pays a facility fee on the total amount of the commitment. Under this agreement, ComfortLink had outstanding $34 million at December 31, 2000 and $33 million at December 31, 1999.

Mortgage and Construction Loans

Our nonregulated businesses' mortgage and construction loans have varying terms. The following mortgage notes require monthly principal and interest payments:

- 8.00%, due in 2001
- 9.65%, due in 2028
- 4.25%, due in 2009
- 8.00%, due in 2033

The variable rate mortgage notes and construction loans require periodic payment of principal and interest.

Unsecured Notes

The unsecured notes mature on the following schedule:

	Amount
	(In millions)
7.66%, due May 5, 2001	$135.0
5.67%, due May 5, 2001	152.0
Total unsecured notes at December 31, 2000	$287.0

Maturities of Long-Term Debt

All of our long-term borrowings mature on the following schedule (includes sinking fund requirements):

Year	Constellation Energy	Nonregulated Businesses	BGE
		(In millions)	
2001	$ —	$318.9	$ 481.2
2002	200.0	15.3	319.8
2003	200.0	0.8	285.7
2004	—	8.3	155.3
2005	300.0	6.1	46.9
Thereafter	300.0	320.6	1,112.4
Total long-term debt at December 31, 2000	$1,000.0	$670.0	$2,401.3

At December 31, 2000, BGE had long-term loans totaling $221.5 million that mature after 2002 (including $110.0 million of medium-term notes discussed in this Note under "BGE's Other Long-Term Debt") that lenders could potentially require us to repay early. Of this amount, $111.5 million could be repaid in 2001, $60.0 million in 2002, and $50.0 million thereafter. At December 31, 2000, $86.5 million is classified as current portion of long-term debt as a result of these provisions.

At December 31, 2000, our nonregulated businesses had long-term loans totaling $20.0 million that mature after 2002 that lenders could potentially require us to repay early. This amount is classified as current portion of long-term debt as a result of these repayment provisions.

Weighted-Average Interest Rates for Variable Rate Debt

Our weighted-average interest rates for variable rate debt were:

Year ended December 31,	**2000**	1999
Nonregulated Businesses (including Constellation Energy)		
Floating rate notes	**6.98%**	—%
Loans under credit agreement	**6.64**	5.68
Mortgage and construction loans	**7.78**	6.65
Tax-exempt debt transferred from BGE	**4.26**	—
BGE		
Remarketed floating rate series mortgage bonds	**6.59%**	5.19%
Floating rate series mortgage bonds	—	5.41
Floating rate reset notes	**7.27**	—
Medium-term notes, Series G	**6.58**	5.38
Medium-term notes, Series H	**6.58**	5.64
Pollution control loan	—	3.22
Port facilities loan	—	3.24
Adjustable rate pollution control loan	—	3.59
Economic development plan	—	3.26
Variable rate pollution control plan	—	3.30

9 Leases

There are two types of leases—operating and capital. Capital leases qualify as sales or purchases of property and are reported in the Consolidated Balance Sheets. Capital leases are not material in amount. All other leases are operating leases and are reported in the Consolidated Statements of Income. We present information about our operating leases below.

Outgoing Lease Payments

We, as lessee, lease some facilities and equipment used in our businesses. The lease agreements expire on various dates and have various renewal options. We expense all lease payments associated with our regulated utility operations.

Lease expense was:

- $11.3 million in 2000,
- $12.2 million in 1999, and
- $10.5 million in 1998.

At December 31, 2000, we owed future minimum payments for long-term, noncancelable, operating leases as follows:

Year	
	(In millions)
2001	$ 7.8
2002	6.4
2003	5.0
2004	3.5
2005	2.9
Thereafter	8.1
Total future minimum lease payments	$33.7

10 Commitments, Guarantees, and Contingencies

Commitments

We have made substantial commitments in connection with our domestic merchant energy business construction program for future years. In addition, we have two long-term contracts for the purchase of electric generating capacity and energy. The contracts expire in 2001 and 2013. We made payments under these contracts of:

- $77.3 million in 2000,
- $67.8 million in 1999, and
- $70.7 million in 1998.

At December 31, 2000, we estimate our future payments for capacity and energy that we are obligated to buy under these contracts to be:

Year	
	(In millions)
2001	$ 40.2
2002	16.4
2003	16.0
2004	15.5
2005	15.1
Thereafter	113.6
Total estimated future payments for capacity and energy under long-term contracts	$216.8

Portions of these contracts became uneconomic upon the deregulation of electric generation. Therefore, we recorded a charge and accrued a corresponding liability based on the net present value of the excess of estimated contract costs over the market-based revenues to recover these costs over the remaining terms of the contracts as discussed in Note 4 on page 63. At December 31, 2000, the accrued portion of these contracts was $21.2 million.

Our domestic merchant energy business has committed to contribute additional capital and to make additional loans to some affiliates, joint ventures, and partnerships in which they have an interest. At December 31, 2000, the total amount of investment requirements committed to by our domestic merchant energy business was $181.0 million.

BGE and BGE Home Products & Services have agreements to sell on an ongoing basis an undivided interest in a designated pool of customer receivables. Under the agreements, BGE can sell up to a total of $40 million, and BGE Home Products & Services can sell up to a total of $50 million. Under the terms of the agreements, the buyer of the receivables has limited recourse against BGE and has no recourse against BGE Home Products & Services. BGE and BGE Home Products & Services have recorded reserves for credit losses. At December 31, 2000, BGE had sold $23.9 million and BGE Home Products & Services had sold $42.5 million of receivables under these agreements.

Planned Acquisition

On December 12, 2000, we announced that a subsidiary of Constellation Nuclear will purchase 1,550 megawatts of the 1,757 megawatts total generating capacity of the Nine Mile Point nuclear power plant, located in Scriba, New York. The subsidiary of Constellation Nuclear will buy 100 percent of Unit 1 and 82 percent of Unit 2 for $815 million, including $78 million for fuel. The sale is expected to close in mid-2001 after receipt of all necessary regulatory approvals. Key regulatory approvals are required from the NRC, Federal Energy Regulatory Commission (FERC), and the New York State Public Service Commission.

One-half of the purchase price, or $407.5 million, is due at the closing of the transaction. The sellers will finance the remaining half of the purchase price at an 11.0% fixed rate for a period of five years with equal annual principal repayments. Nine Mile Point includes two boiling-water reactors. Unit 1 is a 609-megawatt reactor that entered service in 1969. Unit 2 is a 1,148-megawatt reactor that began operation in 1988.

Niagara Mohawk Power Corporation is the sole owner of Nine Mile Point Unit 1. The co-owners of Nine Mile Point Unit 2 that are selling their interests include Niagara Mohawk (41 percent), New York State Electric and Gas (18 percent), Rochester Gas & Electric Corporation (14 percent), and Central Hudson Gas & Electric Corporation (9 percent). The Long Island Power Authority, which owns 18 percent of Nine Mile Point Unit 2, has chosen not to sell its portion at this time.

The terms of the transaction include power purchase agreements whereby we have agreed to sell 90 percent of our share of the Nine Mile Point plant's output back to the sellers for approximately 10 years at an average price of nearly $35 per megawatt-hour over the term of the power purchase agreements. The contracts for the output of both plants are based on operation of the individual units.

The sellers will transfer approximately $450 million in decommissioning funds at the time of closing. We believe this transfer is sufficient to meet the decommissioning requirements for our share of the Nine Mile Point site.

Separation Initiatives

On October 23, 2000, we announced three initiatives to advance our growth strategies. The first initiative is that we entered into an agreement (the "Agreement") with an affiliate of The Goldman Sachs Group, Inc. ("Goldman Sachs"). Under the terms of the Agreement, Goldman Sachs will acquire up to a 17.5% equity interest in our domestic merchant energy business, which will be consolidated under a single holding company ("Holdco"). Goldman Sachs will also acquire a ten-year warrant for up to 13% of Holdco's common stock (subject to certain adjustments). The warrant is exercisable six months after Holdco's common stock becomes publicly available. The amount of common stock which Goldman Sachs may receive upon exercise will be equal to the excess of the market price of Holdco's common stock at the time of exercise over the exercise price of $60 per share for all the stock subject to the warrant, divided by the market price. Holdco may at its option pay Goldman Sachs such excess in cash. Goldman Sachs is acquiring its interest and the warrant in exchange for $250 million in cash (subject to adjustment in certain instances) and certain assets related to our power marketing operation. At closing, Goldman Sachs' existing services agreement with our power marketing operation will terminate.

The second initiative is a plan to separate our domestic merchant energy business from our remaining businesses. The separation will create two stand-alone, publicly traded energy companies. One will be a merchant energy business engaged in wholesale power marketing and generation under the name "Constellation Energy Group" after the separation. The other will be a regional retail energy delivery and energy services company, BGE Corp., which will include BGE, our other nonregulated businesses, and our investment in Orion Power Holdings, Inc. ("Orion").

As a result of the separation, shareholders will continue to own all of Constellation Energy's current businesses through their ownership of the new Constellation Energy Group and BGE Corp.

The third initiative is a change in our common stock dividend policy effective April 2001. In a move closely aligned with our separation plan, effective April 2001, our annual dividend is expected to be set at $.48 per share. After the business separation, BGE Corp. expects to pay initial annual dividends of $.48 per share. Constellation Energy Group, as a growing merchant energy company, initially expects to reinvest its earnings in order to fund its growth plans and not to pay a dividend.

The closing of the transaction with Goldman Sachs and the separation are subject to customary closing conditions and contingent upon obtaining regulatory approvals and a Private Letter Ruling from the Internal Revenue Service regarding certain tax matters. The transaction and separation are expected to be completed by mid to late 2001.

Guarantees

At December 31, 2000, Constellation Energy issued guarantees in an amount up to $825.8 million related to credit facilities and contractual performance of certain of its nonregulated subsidiaries. The actual subsidiary liabilities related to these guarantees totaled $586.6 million at December 31, 2000.

At December 31, 2000, our nonregulated businesses had guaranteed outstanding loans and letters of credit of certain power projects and real estate projects totaling $50.1 million. Our nonregulated businesses also guarantee certain other borrowings of various power projects and real estate projects.

BGE guarantees two-thirds of certain debt of Safe Harbor Water Power Corporation. The maximum amount of our guarantee is $23 million. At December 31, 2000, Safe Harbor Water Power Corporation had outstanding debt of $20.0 million, of which $13.3 million is guaranteed by BGE.

We assess the risk of loss from these guarantees to be minimal.

Environmental Matters

We are subject to regulation by various federal, state and local authorities with regard to:

- air quality,
- water quality,
- waste disposal, and
- other environmental matters.

We discuss the significant matters below.

Clean Air

The Clean Air Act of 1990 contains two titles designed to reduce emissions of sulfur dioxide and nitrogen oxide (NOx) from electric generating stations—Title IV and Title I.

Title IV addresses emissions of sulfur dioxide. Compliance is required in two phases:

- Phase I became effective January 1, 1995. We met the requirements of this phase by installing flue gas desulfurization systems, switching fuels, and retiring some units.
- Phase II became effective January 1, 2000. We met the compliance requirements through a combination of switching fuels and allowance trading.

We will meet the ongoing compliance requirements through a combination of switching fuels and allowance trading.

Title I addresses emissions of NOx. The Maryland Department of the Environment (MDE) issued regulations, effective October 18, 1999, which required up to 65% NOx emissions reductions by May 1, 2000. We entered into a settlement agreement with the MDE since we could not meet this deadline. Under the terms of the settlement agreement, BGE will install emissions reduction equipment at two sites by May 2002. In the meantime, we are taking steps to control NOx emissions at our generating plants.

The Environmental Protection Agency (EPA) issued a final rule in September 1998 that required up to 85% NOx emissions reduction by 22 states including Maryland and Pennsylvania. Maryland and Pennsylvania expect to meet the requirements of the rule by 2003. The emissions reduction equipment installations discussed above will allow us to meet these requirements.

We currently estimate that the controls needed at our generating plants to meet the MDE's 65% NOx emission reduction requirements will cost approximately $150 million. Through December 31, 2000, we have spent approximately $115 million to meet the 65% reduction requirements. We estimate the additional cost for the EPA's 85% reduction requirements to be approximately $55 million by the end of 2002.

In July 1997, the EPA published new National Ambient Air Quality Standards for very fine particulates and revised standards for ozone attainment. In 1999, these new standards were successfully challenged in court. The EPA appealed the 1999 court rulings to the Supreme Court. In May 2000, the Supreme Court decided to hear the EPA's appeal. While these standards may require increased controls at our fossil generating plants in the future, implementation, if required, would be delayed for several years. We cannot estimate the cost of these increased controls at this time because the states, including Maryland and Pennsylvania, still need to determine what reductions in pollutants will be necessary to meet the EPA standards.

In December 2000, the EPA issued a determination that coal-fired power plant mercury emissions will be controlled. Final regulations are expected to be issued in 2004 with controls required by 2007. The costs of these controls cannot be estimated at this time since the level of control or system to implement them have not yet been established.

We received letters from the EPA requesting us to provide certain information under Section 114 of the federal Clean Air Act regarding some of our electric generating plants. This information is to determine compliance with the Clean Air Act and state implementation plan requirements, including potential application of federal New Source Performance Standards. In general, such standards can require the installation of additional air pollution control equipment upon the major modification of an existing plant. We believe our generating plants have been operated in accordance with the Clean Air Act and the rules implementing the Clean Air Act. However, we cannot estimate the impact of this inquiry on our generating plants, and our financial results, at this time.

Waste Disposal

The EPA and several state agencies have notified us that we are considered a potentially responsible party with respect to the cleanup of certain environmentally contaminated sites owned and operated by others. We cannot estimate the cleanup costs for all of these sites.

We can, however, estimate that our current 15.47% share of the reasonably possible cleanup costs at one of these sites, Metal Bank of America, a metal reclaimer in Philadelphia, could be as much as $2.3 million higher than amounts we have recorded as a liability on our Consolidated Balance Sheets. This estimate is based on a Record of Decision issued by the EPA.

Also, we are coordinating investigation of several sites where gas was manufactured in the past. The investigation of these sites includes reviewing possible actions to remove coal tar. In late December 1996, we signed a consent order with the MDE that required us to implement remedial action plans for contamination at and around the Spring Gardens site, located in Baltimore, Maryland. We submitted the required remedial action plans and they were approved by the MDE. Based on the remedial action plans, the costs we consider to be probable to remedy the contamination are estimated to total $47 million. We have recorded these costs as a liability on our Consolidated Balance Sheets and have deferred these costs, net of accumulated amortization and amounts we recovered from insurance companies, as a regulatory asset. Because of the results of studies at these sites, it is reasonably possible that these additional costs could exceed the amount we recognized by approximately $14 million. We discuss this further in Note 5 on page 64. Through December 31, 2000, we have spent approximately $35 million for remediation at this site.

We do not expect the cleanup costs of the remaining sites to have a material effect on our financial results.

Our potential environmental liabilities and pending environmental actions are described further in our most recent Annual Report on Form 10-K in *Item 1. Business—Environmental Matters.*

Litigation

In the normal course of business, we are involved in various legal proceedings. We discuss the significant matters below.

Employment Discrimination

Miller v. Baltimore Gas and Electric Company, et al.—This action was filed on September 20, 2000 in the U.S. District Court for the District of Maryland. Besides BGE, Constellation Energy Group, Constellation Nuclear and Calvert Cliffs Nuclear Power Plant are also named defendants. The action seeks class certification for approximately 150 past and present employees and alleges racial discrimination at Calvert Cliffs Nuclear Power Plant. The amount of damages is unspecified, however the plaintiffs seek back and front pay, along with compensatory and punitive damages. We believe this case is without merit. However, we cannot predict the timing, or outcome, of it or its possible effect on our, or BGE's, financial results.

Moore v. Constellation Energy Group—This action was filed on October 23, 2000 in the U.S. District Court for the District of Maryland by an employee alleging employment discrimination. Besides Constellation Energy, BGE and Constellation Holdings, Inc. are also named defendants. The Equal Employment Opportunity Commission has previously concluded that it was unable to establish a violation of law. The plaintiff seeks, among other things, unspecific monetary damages and back pay. We believe this case is without merit.

Asbestos

Since 1993, we have been involved in several actions concerning asbestos. The actions are based upon the theory of "premises liability," alleging that we knew of and exposed individuals to an asbestos hazard. The actions relate to two types of claims.

The first type is direct claims by individuals exposed to asbestos. We described these claims in a Report on Form 8-K filed August 20, 1993. We are involved in these claims with approximately 70 other defendants. Approximately 530 individuals that were never employees of BGE each claim $6 million in damages ($2 million compensatory and $4 million punitive). These claims were filed in the Circuit Court for Baltimore City, Maryland in the summer of 1993. We do not know the specific facts necessary to estimate our potential liability for these claims. The specific facts we do not know include:

- the identity of our facilities at which the plaintiffs allegedly worked as contractors,
- the names of the plaintiff's employers, and
- the date on which the exposure allegedly occurred.

To date, 29 of these cases were settled for amounts that were not significant.

The second type is claims by one manufacturer—Pittsburgh Corning Corp. (PCC)—against us and approximately eight others, as third-party defendants. On April 17, 2000, PCC declared bankruptcy and we do not expect PCC to prosecute this claim.

These claims relate to approximately 1,500 individual plaintiffs and were filed in the Circuit Court for Baltimore City, Maryland in the fall of 1993. To date, about 350 cases have been resolved, all without any payment by BGE. We do not know the specific facts necessary to estimate our potential liability for these claims. The specific facts we do not know include:

- the identity of our facilities containing asbestos manufactured by the manufacturer,
- the relationship (if any) of each of the individual plaintiffs to us,
- the settlement amounts for any individual plaintiffs who are shown to have had a relationship to us, and
- the dates on which/places at which the exposure allegedly occurred.

Until the relevant facts for both types of claims are determined, we are unable to estimate what our liability, if any, might be. Although insurance and hold harmless agreements from contractors who employed the plaintiffs may cover a portion of any awards in the actions, our potential liability could be material.

Restructuring Order

In early December 1999, the Mid-Atlantic Power Supply Association (MAPSA), Trigen-Baltimore Energy Corporation and Sweetheart Cup Company, Inc. filed appeals of the Restructuring Order, which were consolidated in the Baltimore City Circuit Court. MAPSA also filed a motion to delay implementation of the Restructuring Order, pending a decision on the merits of the appeals by the court.

On April 21, 2000, the Circuit Court dismissed MAPSA's appeal based on a lack of standing (the right of a party to bring a lawsuit to court) and denied its motion for a delay of the Restructuring Order. However, MAPSA filed an appeal of this decision. On May 24, 2000, the Circuit Court dismissed both the Trigen and Sweetheart Cup appeals.

MAPSA subsequently filed several appeals with the Maryland Court of Special Appeals, the Maryland Court of Appeals, and the Baltimore City Circuit Court. The effect of the appeals was to delay the implementation of customer choice in BGE's service territory.

However, on August 4, 2000, the delay was rescinded and BGE retroactively adjusted its rates as if customer choice had been implemented July 1, 2000.

On September 29, 2000, the Baltimore City Circuit Court issued an order upholding the Restructuring Order.

On October 27, 2000, MAPSA filed an appeal with the Maryland Court of Special Appeals challenging the September 29, 2000 order issued by the Circuit Court. We believe that this appeal is without merit. However, we cannot predict the timing or outcome of this case, which, if adverse, could have a material effect on our, and BGE's, financial results.

Asset Transfer Order

On July 6, 2000, MAPSA and Shell Energy LLC filed, in the Circuit Court for Baltimore City, a petition for review and a delay of the Maryland PSC's order approving the transfer of BGE's generation assets issued on June 19, 2000. The Court denied MAPSA's request for a delay on August 4, 2000, and after a hearing on the petition on August 23, 2000 issued an order on September 29, 2000 upholding the Maryland PSC's order on the asset transfer. On October 27, 2000, MAPSA filed an appeal with the Maryland Court of Special Appeals challenging the September 29, 2000 order issued by the Circuit Court. We also believe that this appeal is without merit. However, we cannot predict the timing or outcome of this case, which, if adverse, could have a material effect on our, and BGE's, financial results.

Calvert Cliffs' License Renewal

On April 11, 2000 the United States Court of Appeals for the District of Columbia Circuit, in *National Whistleblowers Center v. Nuclear Regulatory Commission and Baltimore Gas and Electric Company*, upheld the NRC's denial of the Center's motion to intervene in BGE's license renewal proceeding. The NRC had denied the Center's motion to intervene for failing to file timely contentions. The Center filed a petition for certiorari, a request to hear an appeal, with the U.S. Supreme Court, which was denied.

Nuclear Insurance

If there were an accident or an extended outage at either unit of the Calvert Cliffs Nuclear Power Plant (Calvert Cliffs), it could have a substantial adverse financial effect on us. The primary contingencies that would result from an incident at Calvert Cliffs could include:

- physical damage to the plant,
- recoverability of replacement power costs, and
- our liability to third parties for property damage and bodily injury.

We have insurance policies that cover these contingencies, but the policies have certain industry standard exclusions. Furthermore, the costs that could result from a covered major accident or a covered extended outage at either of the Calvert Cliffs units could exceed our insurance coverage limits.

Insurance for Calvert Cliffs and Third Party Claims

For physical damage to Calvert Cliffs, we have $2.75 billion of property insurance from an industry mutual insurance company. If an outage at either of the two units at Calvert Cliffs is caused by an insured physical damage loss and lasts more than 12 weeks, we have insurance coverage for replacement power costs up to $490.0 million per unit, provided by an industry mutual insurance company. This amount can be reduced by up to $98.0 million per unit if an outage at both units of the plant is caused by a single insured physical damage loss. If accidents at any insured plants cause a shortfall of funds at the industry mutual insurance company, all policyholders could be assessed, with our share being up to $15.4 million.

In addition we, as well as others, could be charged for a portion of any third party claims associated with a nuclear incident at any commercial nuclear power plant in the country. At December 31, 2000, the limit for third party claims from a nuclear incident is $9.54 billion under the provisions of the Price Anderson Act. If third party claims exceed $200 million (the amount of primary insurance), our share of the total liability for third party claims could be up to $176.2 million per incident. That amount would be payable at a rate of $20 million per year.

Insurance for Worker Radiation Claims

As an operator of a commercial nuclear power plant in the United States, we are required to purchase insurance to cover radiation injury claims of certain nuclear workers. On January 1, 1998, a new insurance policy became effective for all operators requiring coverage for current operations. Waiving the right to make additional claims under the old policy was a condition for acceptance under the new policy. We describe both the old and new policies below.

Nuclear worker claims reported on or after January 1, 1998 are covered by a new insurance policy with an annual industry aggregate limit of $200 million for radiation injury claims against all those insured by this policy.

All nuclear worker claims reported prior to January 1, 1998 are still covered by the old insurance policies. Insureds under the old policies, with no current operations, are not required to purchase the new policy described above, and may still make claims against the old policies for the next seven years. If radiation injury claims under these old policies exceed the policy reserves, all policyholders could be assessed, with our share being up to $6.3 million.

If claims under these polices exceed the coverage limits, the provisions of the Price Anderson Act (discussed in this section) would apply.

California Power Purchase Agreements

Constellation Power, Inc. and subsidiaries and Constellation Investments, Inc. (whose power projects are managed by Constellation Power) have $297.9 million invested in 14 projects that sell electricity in California under power purchase agreements called "Interim Standard Offer No. 4" agreements. Under these agreements, the projects supply electricity to utility companies at:

- a fixed rate for capacity and energy for the first 10 years of the agreements, and
- a fixed rate for capacity plus a variable rate for energy based on the utilities' avoided cost for the remaining term of the agreements.

Generally, a "capacity rate" is paid to a power plant for its availability to supply electricity, and an "energy rate" is paid for the electricity actually generated. "Avoided cost" generally is the cost of a utility's cheapest next-available source of generation to service the demands on its system.

We use the term "transitioned" to describe when the 10-year periods for fixed energy rates have expired for these power generation projects and they began supplying electricity at variable rates. In 2000, the last four projects transitioned to variable rates.

Prior to 2000, the projects that have transitioned to variable rates have had lower revenues under variable rates than they did under fixed rates. In 2000, the prices received under these agreements were higher due to the increases in the variable-rate pricing terms.

11 Fair Value of Assets and Liabilities from Energy Trading Activities and Financial Instruments

Assets and Liabilities from Energy Trading Activities
As described in Note 1 on page 54, we report assets and liabilities from energy trading activities at fair value.

At December 31, 2000, the notional amounts and terms of trading instruments at Constellation Power Source were as follows:

	Purchased	Sold	Maximum Terms in Years
	(Notional amounts in millions)		
Electric energy (megawatt-hours)	391.3	144.2	21
Electric capacity (megawatt-hours)	66.8	84.9	21
Oil (barrels)	8.5	11.9	5
Natural gas (millions of British thermal units)	373.5	316.3	9

Notional amounts express the contractual volume of transactions but do not necessarily represent the amounts to be exchanged by the parties to the instruments. Accordingly, notional amounts do not accurately measure our exposure to market or credit risk.

Financial Instruments
The fair value of a financial instrument represents the amount at which the instrument could be exchanged in a current transaction between willing parties, other than in a forced sale or liquidation. Significant differences can occur between the fair value and carrying amount of financial instruments that are recorded at historical amounts. We used the following methods and assumptions in estimating fair value disclosures for financial instruments.

- Cash and cash equivalents, net accounts receivable, other current assets, certain current liabilities, short-term borrowings, current portion of long-term debt, and certain deferred credits and other liabilities: The amounts reported in the Consolidated Balance Sheets approximate fair value.
- Investments and other assets where it was practicable to estimate fair value: The fair value is based on quoted market prices where available.
- Long-term debt: The fair value is based on quoted market prices where available or by discounting remaining cash flows at current market rates.

We show the carrying amounts and fair values of financial instruments included in our Consolidated Balance Sheets in the following table, and we describe some of the items separately later in this section.

At December 31,	**2000**		1999	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
	(In millions)			
Investments and other assets for which it is:				
Practicable to estimate fair value	**$ 349.8**	**$ 349.8**	$ 313.3	$ 313.3
Not practicable to estimate fair value	**43.5**	**N/A**	46.7	N/A
Fixed-rate long-term debt	**2,734.1**	**2,819.9**	2,728.9	2,637.3
Variable-rate long-term debt	**1,331.8**	**1,243.3**	654.8	654.8

It was not practicable to estimate the fair value of investments held by our nonregulated businesses in:

- several financial partnerships that invest in nonpublic debt and equity securities, and
- several partnerships that own solar powered energy production facilities.

This is because the timing and amount of cash flows from these investments are difficult to predict. We report these investments at their original cost in our Consolidated Balance Sheets.

The investments in financial partnerships totaled $32.7 million at December 31, 2000 and $35.8 million at December 31, 1999, representing ownership interests up to 11%. The total assets of all of these partnerships totaled $6.1 billion at December 31, 1999 (which is the latest information available).

The investments in solar powered energy production facility partnerships totaled $10.8 million at December 31, 2000 and $10.9 million at December 31, 1999, representing ownership interests up to 13%. The total assets of all of these partnerships totaled $26.7 million at December 31, 1999 (which is the latest information available).

Guarantees
It was not practicable to determine the fair value of certain loan guarantees of Constellation Energy and its subsidiaries. Constellation Energy guaranteed outstanding debt of $341.0 million at December 31, 2000 and $16.5 million at December 31, 1999. Our nonregulated businesses guaranteed outstanding debt totaling $50.1 million at December 31, 2000 and $48.8 million at December 31, 1999. BGE guaranteed outstanding debt of $13.3 million at December 31, 2000 and $13.6 million at December 31, 1999. We do not anticipate that we will need to fund these guarantees.

12 Stock-Based Compensation

As permitted by SFAS No. 123, *Accounting for Stock-Based Compensation*, we measure our stock-based compensation in accordance with Accounting Principles Board Opinion (APB) No. 25, *Accounting for Stock Issued to Employees*, and related interpretations.

Under our existing long-term incentive plans, we can issue awards that include stock options and performance-based restricted stock to officers and key employees. Under the plans, we can issue up to a total of 6,000,000 shares for these awards.

Stock Options

In May 2000, our Board of Directors approved the issuance of non-qualified stock options. The options were granted at prices not less than the market value of the stock at the date of grant, generally become exercisable ratably over a three-year period beginning one-year from the date of grant, and expire ten years from the date of grant. The grants provide for the exercise of the options on a pro-rata basis for service to date upon the separation of our businesses. The tables below do not reflect the impact of the business separation. In accordance with APB No. 25, no compensation expense is recognized for the stock option awards. Summarized information for our stock option awards is as follows:

	Shares	Weighted-Average Exercise Price
	(In thousands, except per share amounts)	
Outstanding at January 1, 2000	—	$ —
Granted	2,462	34.64
Exercised	—	—
Cancelled/Expired	(42)	(34.25)
Outstanding at December 31, 2000	2,420	$34.65
Exercisable at December 31, 2000	—	—
Weighted-average fair value per share of options granted during year		$ 5.60

A summary of the weighted-average remaining contractual life and the weighted-average exercise price of options outstanding as of December 31, 2000 is presented below:

Range of Exercise Prices	Options Outstanding at December 31, 2000 (In thousands)	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life (In years)
$34.25-$40.72	2,420	$34.65	9.4

Performance-Based Restricted Stock Awards

In addition, we issue common stock based on meeting certain performance and service goals that vests to participants at various times ranging from three to five years. In accordance with APB No. 25, we recognize compensation expense for our restricted stock awards. Compensation expense recorded was $16.3 million for 2000 and $10.5 million for 1999. Prior to 1999, compensation expense was not material. Summarized share information for our restricted stock awards is as follows:

	2000	1999
	(In thousands, except per share amounts)	
Outstanding, beginning of year	**323**	350
Granted	**353**	358
Released to participants	**(277)**	(362)
Cancelled	**(22)**	(23)
Outstanding, end of year	**377**	323
Weighted-average fair value per share of restricted stock granted during the year	**$32.89**	$28.61

Pro-forma Information

Disclosure of pro-forma information regarding net income and earnings per share is required under SFAS No. 123, which uses the fair value method. The fair values of our stock-based awards were estimated as of the date of grant using the Black-Scholes option pricing model based on the following weighted-average assumptions:

	2000
Risk-free interest rate	**6.37%**
Expected life (in years)	**10.0**
Expected market price volatility factors	**21.0%**
Expected dividend yields	**5.7%**

The effect of applying SFAS No. 123 to our stock-based awards results in net income and earnings per share that are not materially different from amounts reported.

13 Quarterly Financial Data (Unaudited)

Our quarterly financial information has not been audited but, in management's opinion, includes all adjustments necessary for a fair presentation. Our utility business is seasonal in nature with the peak sales periods generally occurring during the summer and winter months. Accordingly, comparisons among quarters of a year may not represent overall trends and changes in operations.

2000 Quarterly Data

	Revenue	Income from Operations	Earnings Applicable to Common Stock	Earnings Per Share of Common Stock
	(In millions, except per-share amounts)			
Quarter Ended				
March 31	**$ 992.2**	**$182.8**	**$ 72.1**	**$0.48**
June 30	**868.4**	**133.9**	**39.6**	**0.26**
September 30	**981.6**	**315.4**	**147.5**	**0.98**
December 31	**1,036.3**	**208.1**	**86.1**	**0.57**
Year Ended				
December 31	**$3,878.5**	**$840.2**	**$345.3**	**$2.30**

Our first quarter results include a $2.5 million after-tax expense for BGE Employees that elected to participate in a Targeted Voluntary Special Early Retirement Program (TVSERP) (see Note 2).

Our second quarter results include:

- a $15.0 million after-tax deregulation transition cost to a third party incurred by our power marketing operation to provide BGE's standard offer service requirements (see Note 2), and
- a $1.7 million after-tax expense for the TVSERP (see Note 2).

1999 Quarterly Data

	Revenue	Income from Operations	Earnings Applicable to Common Stock	Earnings Per Share of Common Stock
	(In millions, except per-share amounts)			
Quarter Ended				
March 31	$ 983.4	$198.1	$ 82.8	$0.55
June 30	858.5	163.9	68.0	0.45
September 30	1,010.2	277.7	136.1	0.91
December 31	934.1	120.2	(26.8)	(0.18)
Year Ended				
December 31	$3,786.2	$759.9	$260.1	$1.74

Our second quarter results include a $3.6 million after-tax write-down of a financial investment (see Note 3).

Our third quarter results include:

- $7.5 million associated with Hurricane Floyd (see the "Electric Operations and Maintenance Expenses" section of Management's Discussion and Analysis,)
- a $37.5 million deferral of revenues collected associated with the deregulation of our electric generation business (see Note 5),
- a $17.3 million after-tax write-down of a financial investment (see Note 3),
- a $6.7 million after-tax write-off of a power project (see Note 3), and
- a $3.4 million after-tax write-down of certain senior-living facilities (see Note 2).

Our fourth quarter results include:

- a $66.3 million extraordinary charge associated with the Restructuring Order (see Note 4),
- the recognition of the $37.5 million of revenues that were deferred in the third quarter (see above),
- $75 million in amortization expense for the reduction of our generation plants associated with the Restructuring Order (see the "Electric Depreciation and Amortization Expense" section of Management's Discussion and Analysis),
- a $4.9 million after-tax gain on a financial investment (see Note 3),
- $12.0 million after-tax write-downs of certain power projects (see Note 3), and
- a $2.4 million after-tax write-down of certain senior-living facilities (see Note 2).

The sum of the quarterly earnings per share amounts may not equal the total for the year due to the effects of rounding.

CONSTELLATION ENERGY GROUP BOARD OF DIRECTORS

Christian H. Poindexter
Chairman and Chief Executive Officer, Constellation Energy Group
Age 62
Director since 1988*

H. Furlong Baldwin
Chairman, Mercantile Bankshares Corporation
Age 69
Director since 1988*

Douglas L. Becker
Chairman and Chief Executive Officer, Sylvan Learning Systems, Inc.
Age 35
Director since 1998*

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Managing Director, Mid-Atlantic of Ballantrae International, Ltd.
Age 60
Director since 1998**

Beverly B. Byron
Former Congresswoman, U.S. House of Representatives
Age 68
Director since 1993*

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Age 71
Director since 1977*

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Chairman and Chief Executive Officer, Iridium Satellite, LLC
Age 69
Director since 1992*

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Vice Chairman, Constellation Energy Group
Age 62
Director since 1988*

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Partner, Winston & Strawn
Age 47
Director since 1994*

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Head, Energy Practice; Member, PA Management Group
Age 54
Director since 1998**

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Retired Chairman, PHH Corporation
Age 71
Director since 1980*

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President, University of Maryland Baltimore County
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Director since 1994*

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Director since October 2000

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Chairman and Chief Executive Officer, American Life and Accident Insurance Company of Kentucky
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Attorney at Law, Law Offices of Peter G. Angelos
Age 71
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Mayo A. Shattuck, III
Co-Chairman and Co-Chief Executive Officer, DB Alex. Brown, LLC and Deutsche Banc Securities, Inc.
Age 46
Director since 1998**

Michael D. Sullivan
Chairman, Golf America Stores, Inc.
Age 61
Director since 1992*

Standing, from left, back row: Mr. Brady, Mr. Colussy, Mr. Cole, Mr. Baldwin, Mr. Curtiss, Mr. Larson

Standing, from left, middle row: Mr. Russell, Mr. Hurst, Mr. Gale, Mr. Sullivan, Ms. Byron, Mr. Geckle, Dr. Hrabowski

Seated, from left: Mr. Shattuck, Mr. Crooke, Mr. Poindexter, Ms. Lampton

Not pictured: Mr. Becker

* Formerly a BGE Director, was elected to the Constellation Energy Group Board of Directors in April 1999 when BGE shareholders approved the formation of a holding company.

** Formerly a Constellation Enterprises Director, was elected to the Constellation Energy Group Board of Directors in April 1999.

Committees of the Board

Audit Committee
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Douglas L. Becker
James T. Brady
George L. Russell, Jr.

Committee On Management
Jerome W. Geckle, Chairperson
J. Owen Cole
Dan A. Colussy
Mayo A. Shattuck, III
Michael D. Sullivan

Committee On Nuclear Power
James R. Curtiss, Chairperson
Beverly B. Byron
Dr. Freeman A. Hrabowski, III
Charles R. Larson

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Edward A. Crooke
George L. Russell, Jr.
Mayo A. Shattuck, III
Michael D. Sullivan

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Edward A. Crooke
Roger W. Gale
Jerome W. Geckle
Robert J. Hurst
Nancy Lampton
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Michael D. Sullivan

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Nancy Lampton
George L. Russell, Jr.

Risk Management Committee
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Edward A. Crooke
James R. Curtiss
Roger W. Gale
Robert J. Hurst
Charles R. Larson

Constellation Energy Group

Officers

Christian H. Poindexter
Chairman and Chief Executive Officer
Age 62

Edward A. Crooke
Vice Chairman
Age 62

Charles W. Shivery
Co-President
Age 55

Eric P. Grubman
Co-President
Age 43

Thomas F. Brady
Vice President, Corporate Strategy & Development
Age 51

David A. Brune
Vice President, Finance & Accounting, Chief Financial Officer and Secretary
Age 60

Robert S. Fleishman
Vice President, Corporate Affairs and General Counsel
Age 47

Janet E. McHugh
Vice President, Human Resources
Age 43

Richard M. Bange, Jr.
Controller and Assistant Secretary
Age 56

Thomas E. Ruszin, Jr.
Treasurer and Assistant Secretary
Age 46

Merchant Energy Business Leaders

Charles W. Shivery
President and Chief Executive Officer
Constellation Power Source Holdings, Inc.
Age 55

Robert E. Denton
President and Chief Executive Officer
Constellation Nuclear, LLC
Age 58

Utility and Retail Energy Services Business Leaders

Frank O. Heintz
President and Chief Executive Officer
Baltimore Gas and Electric Company
Age 56

William H. Munn
President and Chief Executive Officer
BGE Home Products & Services, Inc.
Age 53

Gregory S. Jarosinski
President and Chief Executive Officer
Constellation Energy Source, Inc.
Age 48

Steven D. Kesler
President and Chief Executive Officer
Constellation Real Estate Group, Inc.
Constellation Investments, Inc.
Age 49

FIVE-YEAR STATISTICAL SUMMARY

	2000	1999	1998	1997	1996
Common Stock Data					
Quarterly Earnings Per Share					
First Quarter	**$0.48**	$0.55	$0.50	$0.43	$0.62
Second Quarter	**0.26**	0.45	0.39	0.05	0.36
Third Quarter	**0.98**	0.91	1.08	1.11	0.93
Fourth Quarter	**0.57**	(0.18)	0.09	0.12	(0.06)
Total	**$2.30**	$1.74	$2.06	$1.72	$1.85
Earnings Per Share Before Nonrecurring Charges Included in Operations	**$2.43**	$2.48	$2.20	$2.28	$2.27
Dividends					
Dividends Declared Per Share	**$1.68**	$1.68	$1.67	$1.63	$1.59
Dividends Paid Per Share	**1.68**	1.68	1.66	1.62	1.58
Dividend Payout Ratio					
Reported	**73.0%**	96.6%	81.1%	94.8%	85.9%
Excluding nonrecurring charges to earnings	**69.1%**	67.7%	75.9%	71.5%	70.0%
Market Prices					
High	**$52.06**	$31.50	$35.25	$34.31	$29.50
Low	**27.06**	24.69	29.25	24.75	25.00
Close	**45.06**	29.00	30.88	34.13	26.75
Capital Structure					
Long-Term Debt	**53.1%**	48.8%	53.5%	48.0%	45.0%
Short-Term Borrowings	**3.2**	5.4	—	4.7	5.1
BGE Preference Stock	**2.5**	2.7	2.9	4.8	6.5
Common Shareholders' Equity	**41.2**	43.1	43.6	42.5	43.4

The sum of the quarterly earnings per share amounts may not equal the total for the year due to the effects of rounding and changes in the average number of shares outstanding throughout the year.

The quarterly earnings per share amounts include certain one-time adjustments as shown in Note 13 to the Consolidated Financial Statements.

Common Stock Dividends* and Price Ranges

2000

	Dividend Declared	Price High	Price Low
First Quarter	$0.42	$33.81	$27.06
Second Quarter	0.42	35.69	31.25
Third Quarter	0.42	52.06	32.06
Fourth Quarter	0.42	50.50	37.88
Total	$1.68		

1999

	Dividend Declared	Price High	Price Low
First Quarter	$0.42	$31.13	$24.69
Second Quarter	0.42	31.38	25.13
Third Quarter	0.42	30.88	27.19
Fourth Quarter	0.42	31.50	27.50
Total	$1.68		

Dividend Policy

The common stock is entitled to dividends when and as declared by the Board of Directors. There are no limitations in any indenture or other agreements on payment of dividends.

Dividends have been paid on the common stock continuously since 1910. Future dividends depend upon future earnings, the financial condition of the company, and other factors. Effective April 1, 2001, our annual dividend is expected to be set at $.48 per share ($.12 per share quarterly). Upon separation, our merchant energy business initially is not expected to pay a dividend. BGE Corp. initially is expected to pay an annual dividend of $.48 per share ($.12 per share quarterly).

Common Stock Dividend Dates

Record dates are normally on the 10th of March, June, September, and December. Quarterly dividends are customarily mailed to each shareholder on or about the 1st of April, July, October, and January.

Stock Trading

Constellation Energy Group's common stock, which is traded under the ticker symbol CEG, is listed on the New York, Chicago, and Pacific stock exchanges, and has unlisted trading privileges on the Boston, Cincinnati, and Philadelphia exchanges. As of December 31, 2000, there were 60,095 common shareholders of record.

Annual Meeting

The annual meeting of shareholders will be held at 10 a.m. on Friday, April 27, 2001, in the 2nd Floor Conference Room of the Gas and Electric Building, located at 39 W. Lexington Street, Baltimore, Maryland 21201.

Form 10-K

Upon written request, the company will furnish, without charge, a copy of its and BGE's Annual Report on Form 10-K, including financial statements. Requests should be addressed to David A. Brune, Chief Financial Officer and Secretary, Vice President, Finance & Accounting, 20th Floor, 250 W. Pratt St., Baltimore, Maryland 21201.

Auditors

PricewaterhouseCoopers LLP

** Dividends paid prior to April 30, 1999 were on BGE common stock. As a result of the common stock share exchange that occurred on that date, Constellation Energy is the successor to BGE.*

Executive Offices

250 W. Pratt Street
Baltimore, Maryland 21201
Mail: P.O. Box 1475, Baltimore, Maryland 21203-1475

Shareholder Investment Plan

Constellation Energy Group's Shareholder Investment Plan provides common shareholders an easy and economical way to acquire additional shares of common stock. The plan allows shareholders to reinvest all or part of their common stock dividends; purchase additional shares of common stock; deposit the common stock they hold into the plan; and request a transfer or sale of shares held in their accounts.

Stock Transfer Agents and Registrars

Transfer Agent and Registrar:
Constellation Energy Group, Inc.
Baltimore, Maryland

Co-Transfer Agent and Registrar:
Continental Stock Transfer and Trust Company
2 Broadway
New York, NY 10004

Shareholder Assistance and Inquiries

If you need assistance with lost or stolen stock certificates or dividend checks, name changes, address changes, stock transfers, the Shareholder Investment Plan, or other matters, you may visit our Web site at www.constellationenergy.com or contact our shareholder service representatives as follows:

By telephone (Monday–Friday, 8 a.m. – 4:45 p.m. EST):

Baltimore Metropolitan Area	410-783-5920
Within Maryland	1-800-492-2861
Outside Maryland	1-800-258-0499

By U.S. mail:
Constellation Energy Group, Inc.
Shareholder Services
P.O. Box 1642
Baltimore, MD 21203-1642

In person or by overnight delivery:
Constellation Energy Group, Inc.
Shareholder Services, Room 800
39 W. Lexington Street
Baltimore, MD 21201

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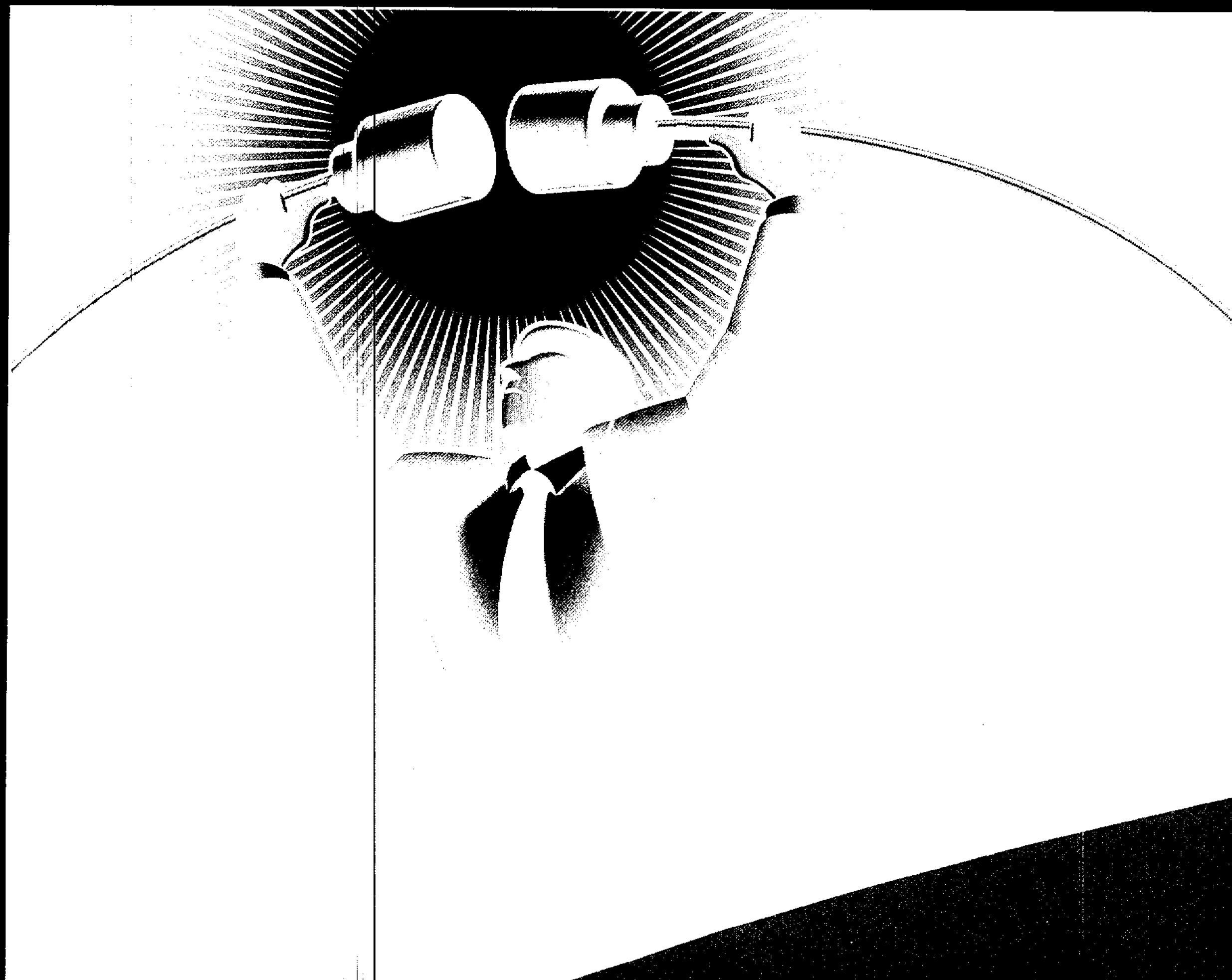
BALANCE OF POWER



In today's energy market, how do you find the critical balance of power?

There's no single answer.

That's why Constellation Energy has put its strengths together to build an integrated energy business. Our balanced energy approach allows us to customize solutions to meet any wholesale customer's needs.

We market and trade power.

We manage risk.

We generate competitively priced electricity.

We build and operate power plants.

At Constellation Energy, we're balancing the power to build energy solutions for our customers now and for the future.

Constellation Energy Group

www.constellationenergy.com

EXHIBIT II

QUARTERLY FINANCIAL STATEMENTS

AS OF JUNE 30, 2001

Calvert Cliffs Nuclear Power Plant, Inc.
August 15, 2001

Constellation Energy Group and Subsidiaries

Supplemental Financial Statistics

	Twelve Months Ended June 30, 2001	2000
Capitalization*		
Long-term debt	43.0%	49.5%
Company obligated mandatorily redeemable trust preferred securities of BGE	3.0%	3.4%
Short-term borrowings	3.8%	3.0%
BGE Preference stock	2.3%	2.6%
Common equity	47.9%	41.5%
Return on Average Common Equity		
Reported	12.7%	7.3%
Excluding nonrecurring items included in earnings from operations * *	12.5%	11.7%
Ratio of Earnings to Fixed Charges (SEC Method)	3.01	2.61
Effective Tax Rate	37.8%	36.9%

* *Capitalization includes current portions of long-term debt and BGE preference stock.*

** *Nonrecurring items included in earnings from operations are shown on the Consolidated Statements of Income.*

Common Stock Data

	Three Months Ended June 30,		*Twelve Months Ended June 30,*	
	2001	*2000*	*2001*	*2000*
Common Stock Dividends - Per Share				
--Declared	$0.12	$0.42	$1.08	$1.68
--Paid	$0.12	$0.42	$1.38	$1.68
Market Value Per Share				
--High	$50.14	$35.69	$52.06	$35.69
--Low	$40.10	$31.25	$32.06	$27.06
--Close	$42.60	$32.56	$42.60	$32.56
Shares Outstanding--End of Period *(In Millions)*	163.7	149.7	163.7	149.7
Book Value per Share--End of Period	$24.22	$20.11	$24.22	$20.11

Inquires concerning this summary should be directed to:

Follin Smith
Senior Vice President,
Chief Financial Officer
410-234-5000

Kevin J. Miller
Manager,
Financial Planning
410-783-3670

Constellation Energy Group
P. O. Box 1475
Baltimore, Maryland 21203

EXHIBIT III

PROJECTED CASH FLOW FOR 12 MONTHS

ENDED JULY 31, 2002

Internal Cash Flow Projection

For Calvert Cliffs Nuclear Power Plant

Percentage Ownership in all Operating Nuclear Units	Calvert Cliffs Unit No. 1	100.00%
	Calvert Cliffs Unit No. 2	100.00%
Maximum Total Contingent Liability (000) per Nuclear Incident	$176,200	
Payable at Per Year (000)	$20,000	

	Actual Twelve Months Ended 6/30/01	Projected Twelve Months Ended 7/31/02
Non - Cash Expenses ($000)		
Depreciation and Amortization	$464,200	$178,900
Deferred Income Taxes and Investment Tax Credits	56,300	136,600
Total	$520,500	$315,500
Percentage of Total to Maximum Total Contingent Liability Payable Per Year	2,602.5%	1,577.5%
Retained Earnings ($000)		
Net Income After Taxes	$421,000	
Less Allowance for Funds Used During Construction	1,400	
Less Dividends paid	206,500	
Total	$213,100	
Total Internal Cash Flow	$733,600	
Percentage of Total Internal Cash Flow Maximum Total Contingent Liability Payable Per Year	3,668%	

Constellation Energy Group

Underlying Assumptions for Projected Cash Flows

(1) Projected cash flow does not include an estimate of retained earnings. However, internally generated funds without retained earnings are well in excess of the maximum possible retrospective premiums. The projected cash flow calculations reflect the non-regulated Constellation Energy Group and consolidated subsidiaries only. The separation of the regulated utility and non-regulated companies is expected to occur in the fourth quarter of 2001.

(2) Depreciation is generally computed using composite straight-line rates applied to the average investment in classes of depreciable property. Vehicles are depreciated based on their estimated useful lives.

(3) Estimates of Federal income taxes and other tax expense are based upon existing tax laws and any known changes thereto.

(4) Accounting policies are consistent with those in effect June 30, 2001.

(5) Both the actual and projected data provided in this filing are for Constellation Energy Group, which included the Nuclear Generation business. On June 30, 2000 the Nuclear Regulatory Commission approved the transfer of the Calvert Cliffs Nuclear Power Plant operating license from Baltimore Gas and Electric Company to Calvert Cliffs Nuclear Power Plant, Inc. (CCNPP). Effective July 1, 2000, in accordance with state legislation passed in November 1999, CCNPP became a separate unregulated company. In light of this change, all subsequent financial assurance filings are being provided by Constellation Energy Group.

EXHIBIT IV

NARRATIVE STATEMENT

CURTAILMENT OF CAPITAL EXPENDITURES

Calvert Cliffs Nuclear Power Plant, Inc.
August 15, 2001

Constellation Energy Group

Curtailment of Capital Expenditures

Estimated construction expenditures including nuclear fuel and Allowance for Funds Used During Construction for the twelve months ended July 31, 2002 are $784 million. To insure that retrospective premiums under the Price Anderson Act would be available during the aforementioned twelve month period without additional funds from external sources, construction curtailments would affect all construction expenditures rather than impacting a specific project.