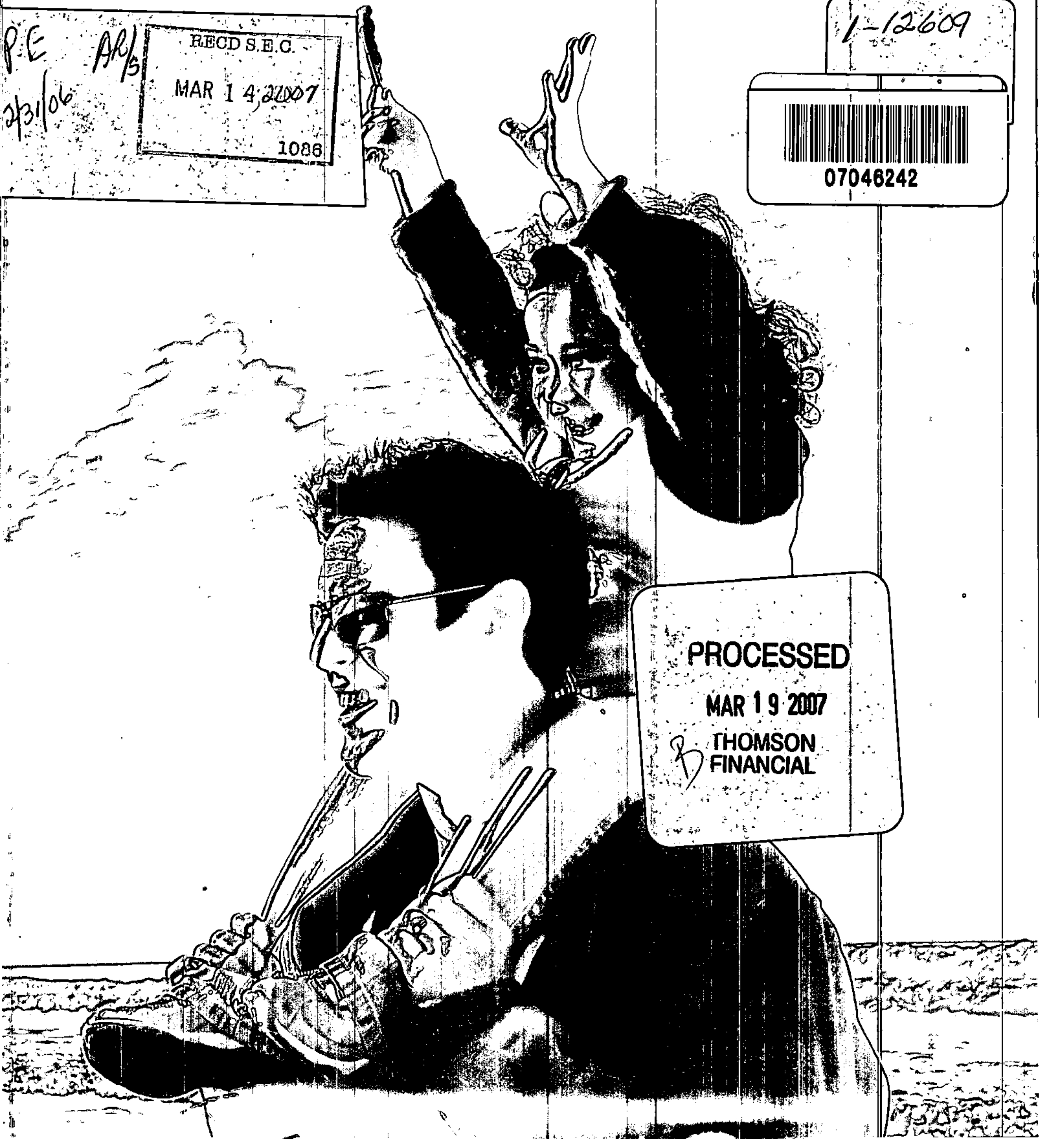
PG&E CORPORATION ANNUAL REPORT 2006

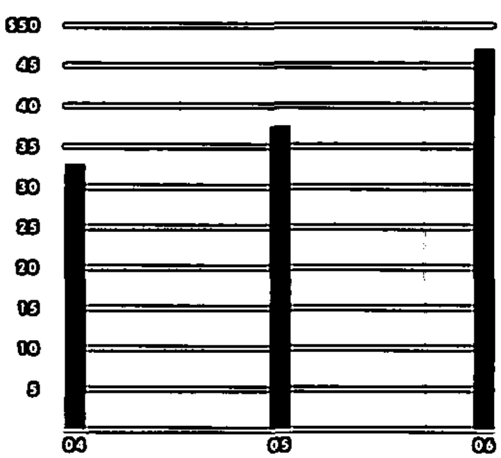
Riding on Our Shoulders Is a Lot More Than Just a Company, It's Also Our Customers' Future.



HOW WE PERFORMED IN 2006:

- PG&E Corporation shareholders earned a total return of 31.6 percent on their investment in PG&E for the year.
- Our stock price grew by 27.5 percent in 2006, and hit an all-time high closing price of $47.98 in December.
- We grew year-over-year earnings from operations by nearly 10 percent to $2.57 per share.*

PG&E CORPORATION STOCK PERFORMANCE
(Year-end closing stock price)



*Earnings from operations is not a substitute for consolidated net income reported under generally accepted accounting principles (GAAP). We present "earnings from operations" in order to provide a measure that allows investors to compare our underlying financial performance from one period to another, exclusive of items that management believes do not reflect the normal course of operations. See the "Financial Highlights" table on page 51 for a reconciliation of earnings from operations with GAAP consolidated net income.

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A LETTER TO OUR STAKEHOLDERS:

Today at PG&E, we are thinking about the customer experience more holistically than ever before. It encompasses the accessibility, affordability and reliability of services that are essential to customers' everyday lives. The resources to power their businesses. The infrastructure to support their state and local economies. The health of their air, water, land and planet. The quality of life in their communities. The empowerment to act on their individual values in their daily energy choices. And the peace of mind knowing we are thinking ahead about how society and business will ensure a secure energy future 10, 20 or 50 years from now.

This perspective is guiding us as we keep a sharp focus on our customers and pursue a vision to become the nation's leading utility.

The changes in our company over the past two years have been the result of an unblinking, in-depth appraisal of our operations and culture through the customer's eyes. We confronted the reality that PG&E couldn't secure its future in the evolving utility industry – never mind lead it – unless we embraced new ways of thinking and working.

We have had to become faster and more efficient. More accountable and reliable. More nimble and responsive. More enterprising and innovative. More extroverted and engaged. More open and honest. And, yes, more friendly and approachable.

Although we're still in the thick of this transformation, customers can already see the signs of a new PG&E. We hear it anecdotally, and we see it in our customer satisfaction ratings, which showed marked improvements last year. These and many other signals assure us that PG&E is on the right track.

For a regulated utility, the ultimate transformation is becoming the kind of company that customers do business with because they want to – not because they have to. That's one reason we are running PG&E today with the mindset of a competitive venture that has to win the trust, respect and confidence of its customers every day.

What's also become clear to us, though, is that truly great relationships with customers have to be built on more than just operational excellence and quality service. They're built just as importantly on shared values and priorities. Customers like to know they're doing business with a company that stands for things they also believe in.

Leading companies in other lines of work have known this for a long time. We, too, see it as an essential part of our leadership vision.

So it heartened us last year to see customers nodding in favor as PG&E took a bold stand on global warming, explored innovative new possibilities for clean energy, gave more of our time and resources to the community than ever before, beat our supplier diversity goals, and partnered constructively with other leaders in business and government.

With the totality of our accomplishments in 2006, we are nearer to being the company we aspire to become.

At the same time, there are no illusions: We are not yet where we want to be. Not every change worked smoothly last year. Not every performance metric moved up as far or as fast as we intended. And not every customer is getting the quality service we are committed to providing.

In this year's letter, we will bring you current on the state of our company, share the major steps we're taking to advance our strategy in 2007, and make it clear why we are entering the year with quiet confidence that the changes we are pursuing will put PG&E's vision of industry leadership firmly in our grasp.

WE ARE FINANCIALLY STRONG.

A utility whose finances are healthy and sound is also one that is in the best position to do the right things for its customers. So, it's encouraging to report that our numbers for 2006 were extraordinary.

Earnings per share came in above our targets for the year. Total net income was $991 million, or $2.76 per share, as calculated in accordance with generally accepted accounting principles (GAAP).

On a non-GAAP earnings from operations basis, which excludes items that we consider to be non-operating, earnings per share for 2006 grew by almost 10 percent compared with 2005 to $2.57 per share. This exceeded our projected growth rate of 7.5 percent. (The Financial Highlights table on page 51 explains the comparison of GAAP total net income and non-GAAP earnings from operations.)

We expect to continue growing earnings on a trajectory that is one of the strongest among comparable utilities. Our current forecast calls for annual earnings growth to average at least 7.5 percent over the next five years.

PG&E's strategy and outlook continue to resonate with the market. Last year, investors bid up the value of our shares by more than 27 percent, and the stock price ended 2006 just below the all-time peak it hit in December.

For shareholders, this growth in stock price, plus four quarters of steady common dividends, added up to a total annual return of over 31 percent. Even in a winning year for energy stocks overall, this performance stood out from the pack: PG&E's return beat the S&P 500, the S&P Electrics and the S&P Multi Utility Index.

WE ARE STRENGTHENING OUR SYSTEM.

Like many utilities, we are making major capital additions to our infrastructure in order to support growth and improve existing service. This benefits the homes and businesses we serve, and it provides corresponding opportunities for shareholders to earn additional returns on a growing asset base.

In 2006, these investments totaled approximately $2.4 billion, up from $1.9 billion a year earlier. On average, we expect to sustain or increase this pace of investment through 2011, starting in 2007 when our plans call for spending at least $2.8 billion.

This year, we expect to connect another 75,000 new electric customers and 62,000 new gas customers. We'll expand our local electric and gas distribution networks accordingly. We'll also continue upgrading and replacing hardware, like cables and transformers, to increase reliability.

We're also improving the flow of power in our system, by devoting substantial resources to build and expand electric transmission lines. This is the fastest growing part of our business. These projects are fortifying reliability, creating better access to new and existing power supplies, accommodating development in high-growth areas like Sacramento and the Central Valley, and delivering other benefits. For example, a new transmission line in San Francisco last year enabled us to shut down an old, environmentally obsolete power plant, keeping a promise we made to the customers who live nearby.

Going forward, we've proposed constructing a number of additional gas and electric transmission arteries to create access to new supplies of renewable energy and new sources of natural gas.

In addition to ongoing investment in our existing hydroelectric and nuclear facilities, for the first time in 20 years PG&E is also back in the business of owning and operating new power plants. As part of our long-term resource plan for customers, construction recently began on the first of three state-of-the-art facilities. The plants will be on-line between 2009 and 2010 and will generate enough power for 950,000 homes.

WE ARE BUILDING A CLEANER, MORE SUSTAINABLE ENERGY FUTURE.

If rejuvenating California's energy supply and infrastructure is one trend driving our business, another is the imperative to do it with cleaner, more efficient technologies and smart, sustainable resource planning. This is a priority for our customers, our state and PG&E.

More than 50 percent of the power we deliver already comes from resources that produce no global warming emissions. Combine this with 30 years of experience running the world's most successful customer energy efficiency programs, large and expanding renewable power commitments, one of the utility industry's largest fleets of clean-fuel vehicles, industry-leading habitat conservation strategies, award-winning environmental education programs, and other best practices, and it's easy to see why PG&E ranks as one of the cleanest utilities in the nation, if not the world.

We were the only major utility to stand with Governor Schwarzenegger last year as he signed California's historic global warming law. Our stance reflects our belief that climate change poses a real threat to the planet's future and requires action now. We've also helped forge an alliance of leading companies and environmental groups to call for a federal response on climate change, including General Electric, DuPont, Alcoa, Natural Resources Defense Council, Environmental Defense and others.

"We expect to continue growing earnings on a trajectory that is one of the strongest among comparable utilities."

We know customers are counting on us to find ever cleaner solutions to their energy needs. One of the most important ways we're doing this is by maximizing the benefits of energy efficiency and new renewable supplies before we make plans to build new conventional power plants. Efficiency gains are the most economic and cleanest resource available to meet customers' growing energy demands.

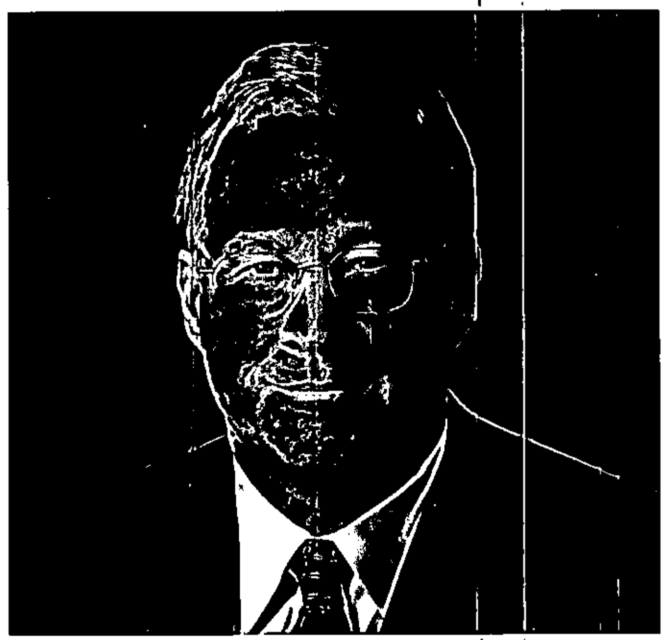
That's why we're now in the midst of a three-year campaign to infuse an additional $1 billion into new energy efficiency programs for residential and business customers in California.

For large customers like Yahoo! and Adobe, we're providing energy analyses and design assistance for their facilities, rebates on energy efficient equipment, incentives to upgrade or change energy management practices, and technical education and training. We're also customizing our programs more than ever before to suit the unique needs of specific customers.

Additionally, we're helping shepherd new energy efficient products and technologies into the market. Last year, for example, our team broke new ground working with leaders like Sun Microsystems, Hewlett-Packard and Intel to set new benchmarks for energy efficiency in servers and other IT hardware. We've created an industry-leading rebate program to support these and any other qualifying products to help trim power use in energy-intensive data centers.

No other utility matches PG&E's expertise in energy efficiency. Our counsel has even been sought by China, where we are facilitating information exchanges and technology deployment to help them cope with their enormous energy needs and the related environmental impacts.

Here at home, as the nation becomes more engaged in pursuing energy efficiency, we see our experience and know-how



as a major leadership advantage for our company, with the potential to open new opportunities for shareholders.

Already one of the nation's largest purchasers of renewable power, PG&E is also aggressively adding new renewable resources. Our stable of renewable resources grew by more than 400 megawatts last year – which will be enough energy for more than 300,000 customers – as we signed a number of contracts for new supplies of wind, solar, geothermal and other renewable power. When pooled with our existing renewables, and additional contracts expected in 2007 and the years ahead, we expect to continue making significant progress toward California's renewable energy goals. Our customers also continue to benefit from PG&E's vast supplies of hydroelectric power.

We're also giving customers options that enable them to act on their own environmental values in their energy choices. PG&E has helped over 13,000 of its customers install solar energy technology at their homes and businesses – far more than any other utility in the United States.

Customers will have a new option this year, as PG&E launches its cutting-edge ClimateSmart program. We'll be the first utility to give customers a choice to offset the global warming impact of their energy use by paying a small additional amount, which PG&E will use to buy or create carbon offsets. We plan to be the first participant, with a commitment to offset the emissions associated with the energy we use in our offices and other facilities.

These highlights only skim the surface of what's happening at PG&E to help revolutionize the way we produce and use energy. We are exploring opportunities associated with plug-in hybrid electric cars, next-generation renewables like large-scale solar thermal power stations and wave power off the coast of our state, renewable natural gas supplies from cows on California dairy farms, collaborating with developers to design sustainable communities ... the list goes on.

"More than 50 percent of the power we deliver already comes from resources that produce no global warming emissions."

Time will tell if these ideas are commercially feasible. Either way, we are confident that by pursuing all the possibilities, we will help advance progress on clean energy and that good things will come to customers and shareholders as a result.

WE ARE BECOMING EASIER TO DO BUSINESS WITH.

Much of the feedback we hear from our customers boils down to the simple idea that it should be easier to do business with PG&E. More convenience. Less time and red tape. Seamless service from one part of the business to another. Access to clear, understandable information. Consistent treatment. Better communication.

We agree, and we're working hard to improve our performance. A typical illustration: Customers loved the first-of-its-kind "10/20 winter gas savings program" we created in 2005. But they told us that figuring out the details was complicated. This winter, we took that feedback, enhanced the program and made it simpler to qualify.

When bills spiked during the summer heat wave last year, we knew customers needed relief. So we rapidly took the unprecedented initiative to refund excess revenues directly to customers, instead of holding on to them to offset future revenue needs.

At our call centers, we made it easier to get help from a live agent when customers need assistance. We also made it easier for the agent by simply enabling them to view an exact copy of the customer's bill on their screen. Common sense changes like this helped us become more effective at resolving customer issues the first time they call. Our numbers at the end of 2006 showed marked improvement over where we began the year.

Another improvement, PG&E recently started offering customers the option to use their Visa cards to pay their monthly bills, either for one-time transactions or for automatic payments.

This year, we're now in the process of redesigning customers' monthly account statements so they are easier to understand and more informative. Most importantly, we're working directly with customers to be sure we get it right.

Our focus on service is paying off. PG&E's J.D. Power and Associates customer satisfaction scores for our electric business improved significantly last year, beating our targets. Additionally, we just learned that business customers rated our natural gas service in a tie for the best in the western region and fourth among all utilities in the nation.

These results tell us that we've begun to make progress. We'll continue to focus heavily in this area in 2007.

WE ARE CAPITALIZING ON NEW TECHNOLOGIES AND PROCESSES.

No other utility in the country is rethinking its operations on a scale matching the ambition or sophistication of the transformation initiative now underway at PG&E.

In scores of areas across the business, the ways that we plan, organize and execute work are being simplified, standardized and consolidated to be more efficient. Offices are being relocated, redesigned and staffed more strategically. Our people are being equipped with and trained on powerful new tools and technologies that function on common platforms to facilitate information sharing.

We've designed these changes with the goal of a quantum leap in performance. When they're complete, we believe the PG&E model will set a new standard for excellence. That's a bold statement. But it reflects our confidence in the path we're now on.

In the end, our customers will see faster turnarounds on service requests, more consistent service, better reliability and quicker responses to outages, and higher quality information about their energy usage, among other benefits. We'll also be operating the business more cost-effectively.

Today, this vision remains a ways off. Major cornerstones of the strategy went into place in 2006 – but the biggest changes lie ahead, and 2007 will be a pivotal year.

Accomplishments in 2006 included installing the first of 10 million SmartMeter™ devices that will be connected to homes and businesses throughout our service area over the next five years. SmartMeter™ technology will enable us to provide customers with new time-of-use service options based on hourly information, connect service remotely and respond more rapidly to outages, among other capabilities.

We also opened seven new Resource Management Centers, centralizing and streamlining work previously done in 70 different locations. As one labor union member put it, "When you walk in ... you know you're not in yesterday's office anymore." Everything from the workstations to workflows has been re-engineered.

We also consolidated our dispatch centers into fewer locations. And we've begun overhauling critical IT infrastructure in our energy distribution and customer service operations.

As will always be the case in major transitions, some missteps are inevitable. We're acknowledging and learning from them as they occur, and we are working through the challenges as quickly as possible.

This year's most critical initiative will be the launch of the new software and tools that will be the foundation for our new service model. Importantly, we're applying lessons we learned last year to shore up gaps in employee training and tighten up our execution.

As in 2006, this year we also will require some good people at PG&E to accept hard sacrifices – retraining, relocating to keep a job, or leaving a job that no longer fits with our operations.

I've talked face-to-face with a number of men and women affected by these changes. These conversations are never easy. But they're deeply important. They remind leaders that change comes with costs, and that we have a duty to make certain that, when sacrifices are made, it's because they are in the best long-term interest of the company and its customers. I'm confident they are, and I'm confident PG&E will make the transition for these members of our company as smooth as possible.

WE ARE ONLY JUST BEGINNING..

In two years, I've seen our company make some remarkable strides. I believe we have assembled the best team in the industry. I believe our strategy is ideally calibrated to capture the best opportunities for growth and value as the industry evolves. And I believe that – even with as much positive change as we've seen – we're only just beginning to glimpse the possibilities that lie ahead for PG&E.

I'm very much an optimist when it comes to PG&E's future and the future we're helping to create for our customers. But I'm also a hard-nosed realist who knows we can't take success for granted.

Our commitment for 2007 is to push forward relentlessly. You can count on us to be responsible, patient and pragmatic as we drive change throughout the business. But you can also count on us to be disciplined about delivering results, because failure isn't an option.

If you're already a PG&E shareholder, we hope you were excited by our performance in 2006. If you aren't one yet, we hope our results and our vision will convince you to become one.

In the meantime, our team of 20,000 men and women will be focused on delivering for you and all of our stakeholders again in 2007.

Sincerely,

Peter A. Darbee
Chairman of the Board, Chief Executive Officer and President
PG&E Corporation

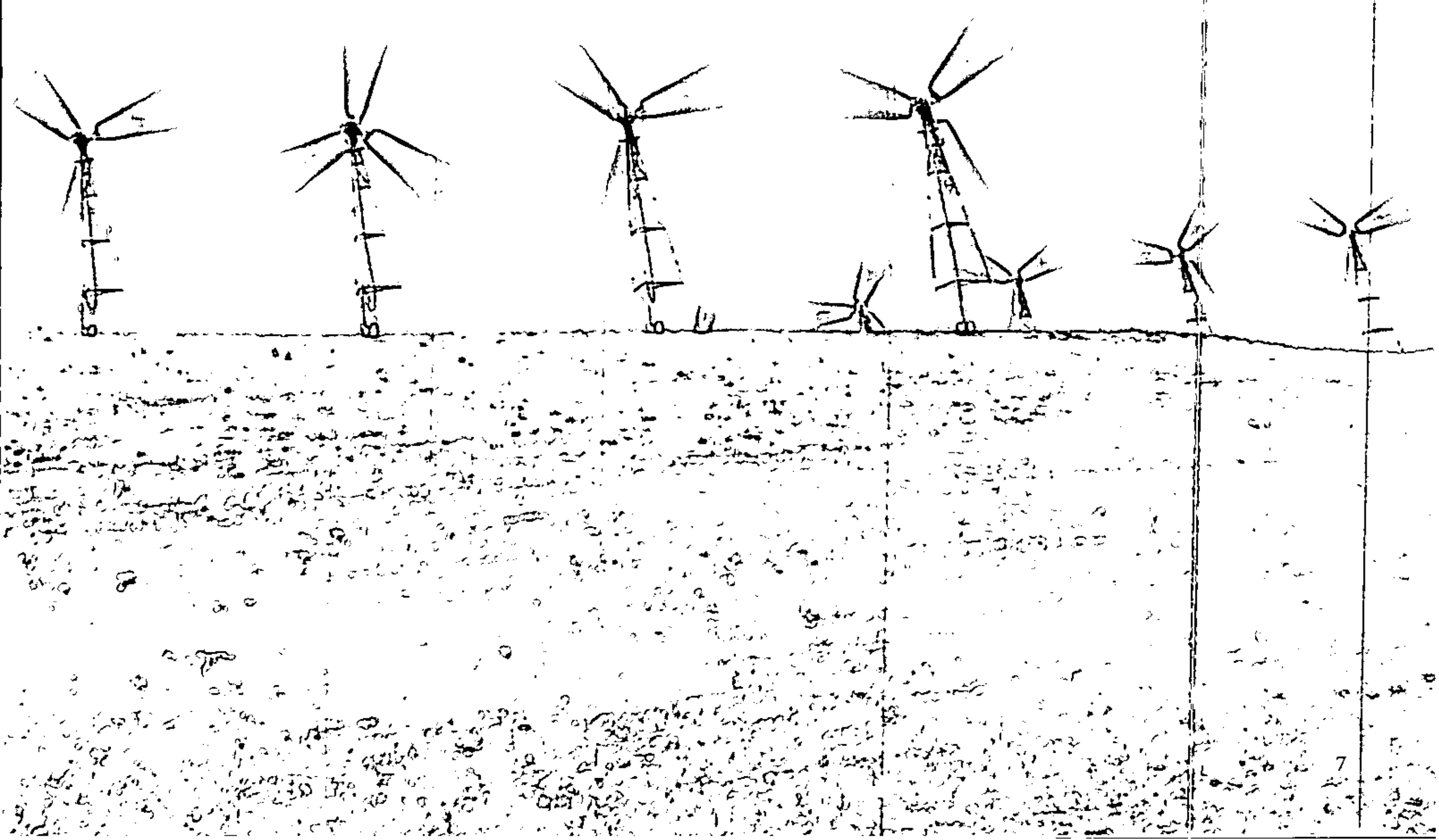
Chairman of the Board
Pacific Gas and Electric Company
February 22, 2007

We're seeking success on behalf of customers in an uncertain world. And so, like customers, we imagine what can be. □ Together, we ask if we can slow global climate change; if we can empower consumers to act on their values in their energy choices; if we can build energy sustainability into our communities; if we can harness the next generation of renewable energy; if we can leverage energy efficiency to transform the economy and the environment. □ These and other crucial questions are worth

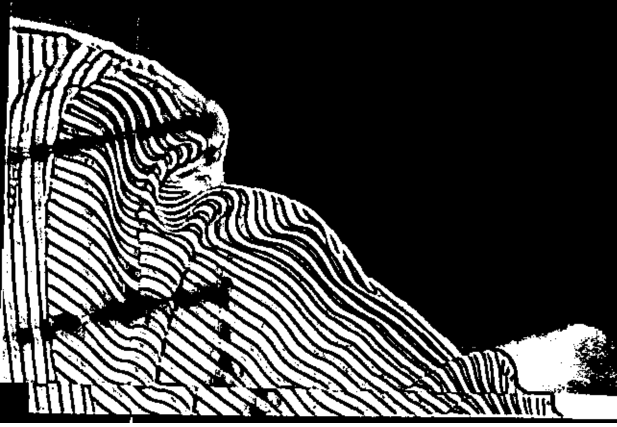
P G & E — I N P U R S U I T

pondering and worth answering. And that's what we're doing as we shape the utility of the 21st century. □ But as bold and decisive as we are, we never rush to judgment. We temper our idealism with pragmatism and our creativity with contemplation. We know that our vision for tomorrow means nothing if it isn't grounded in operational excellence today. □ As we manage for today and think about tomorrow, we will always do The Big Thing or The Difficult Thing, as long as it's The Right Thing for customers.

O F W H A T ' S P O S S I B L E



Can we attract
the best and brightest
minds to create a new
future in a century-old
industry?



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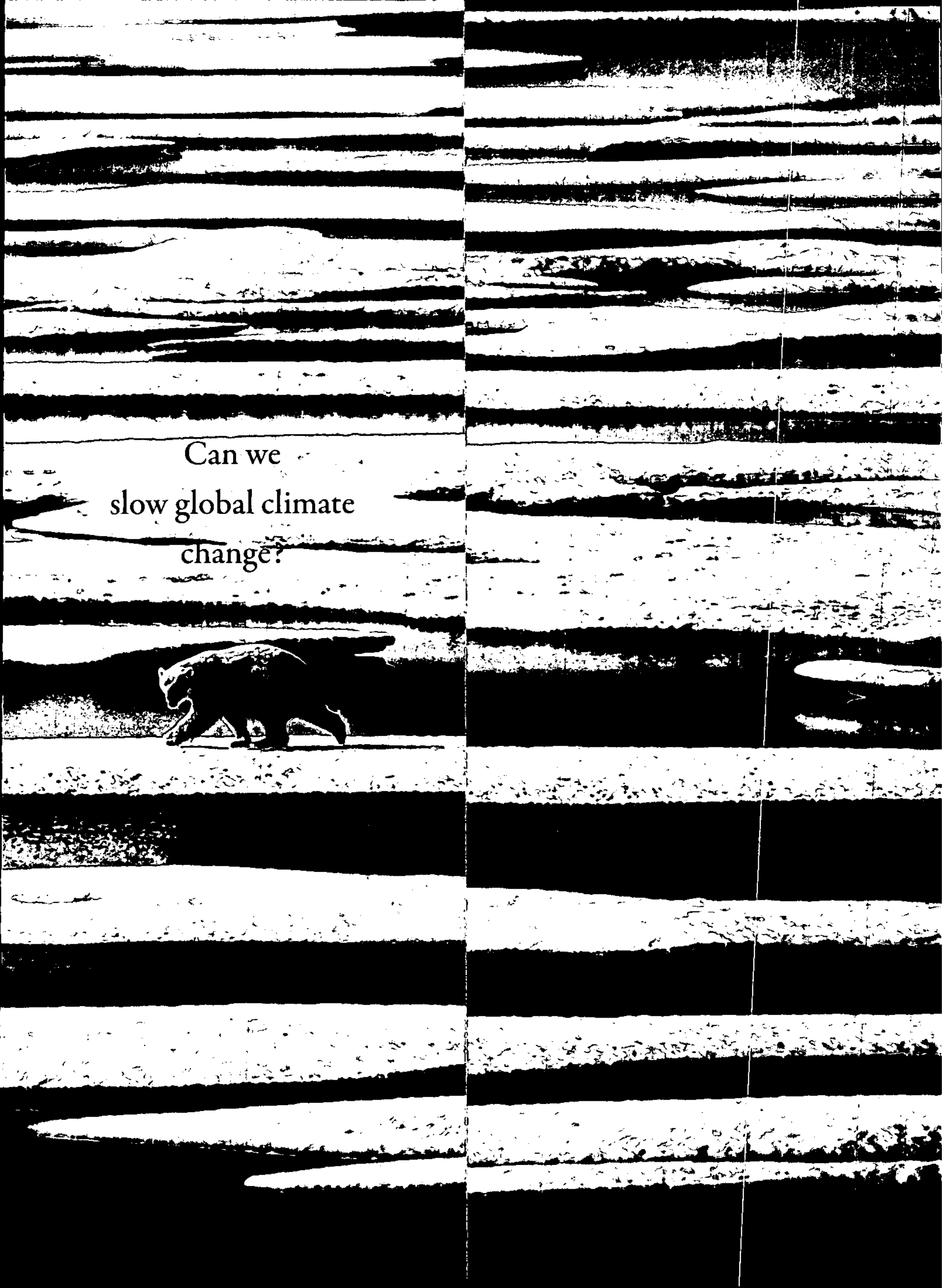
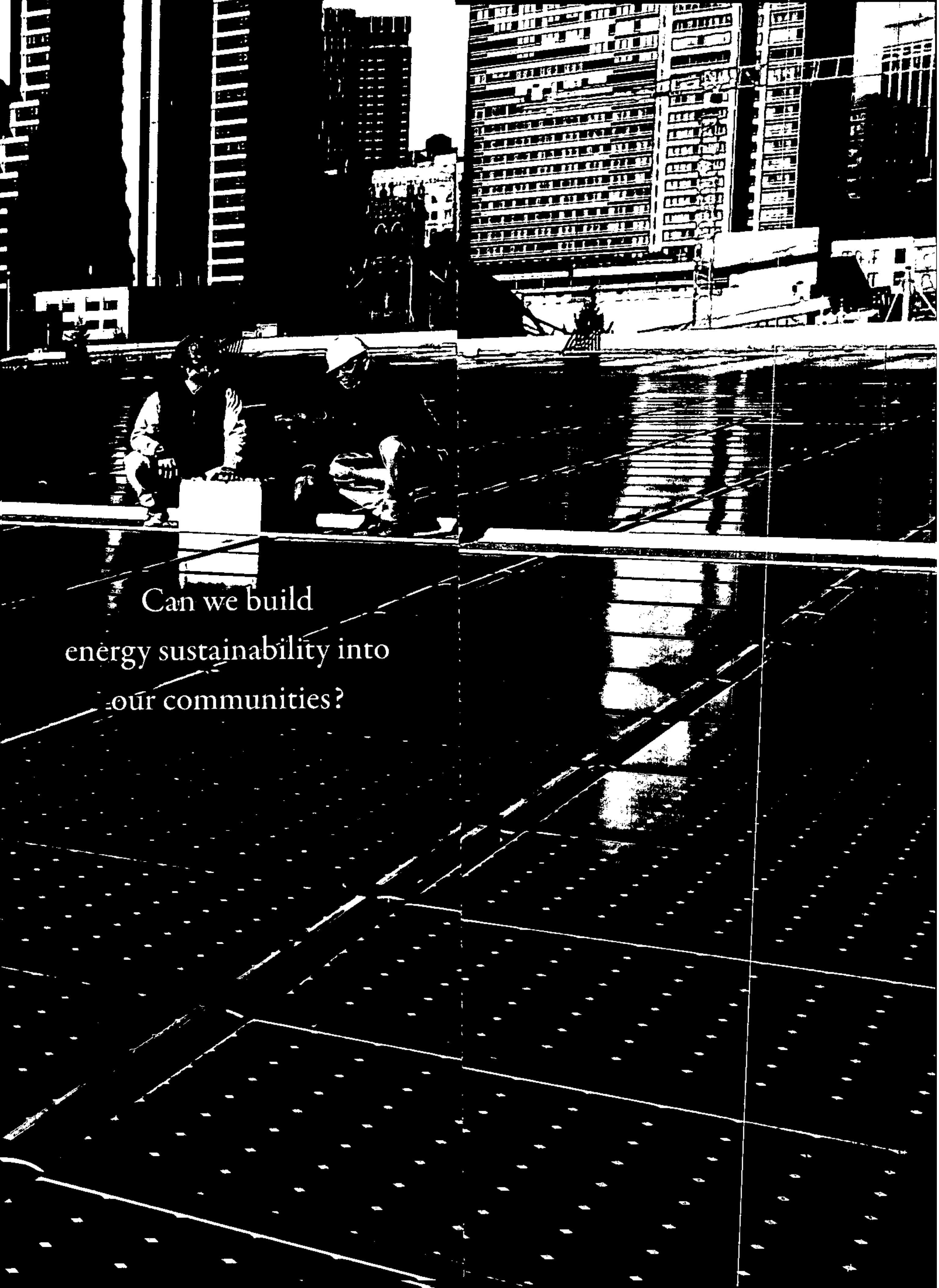
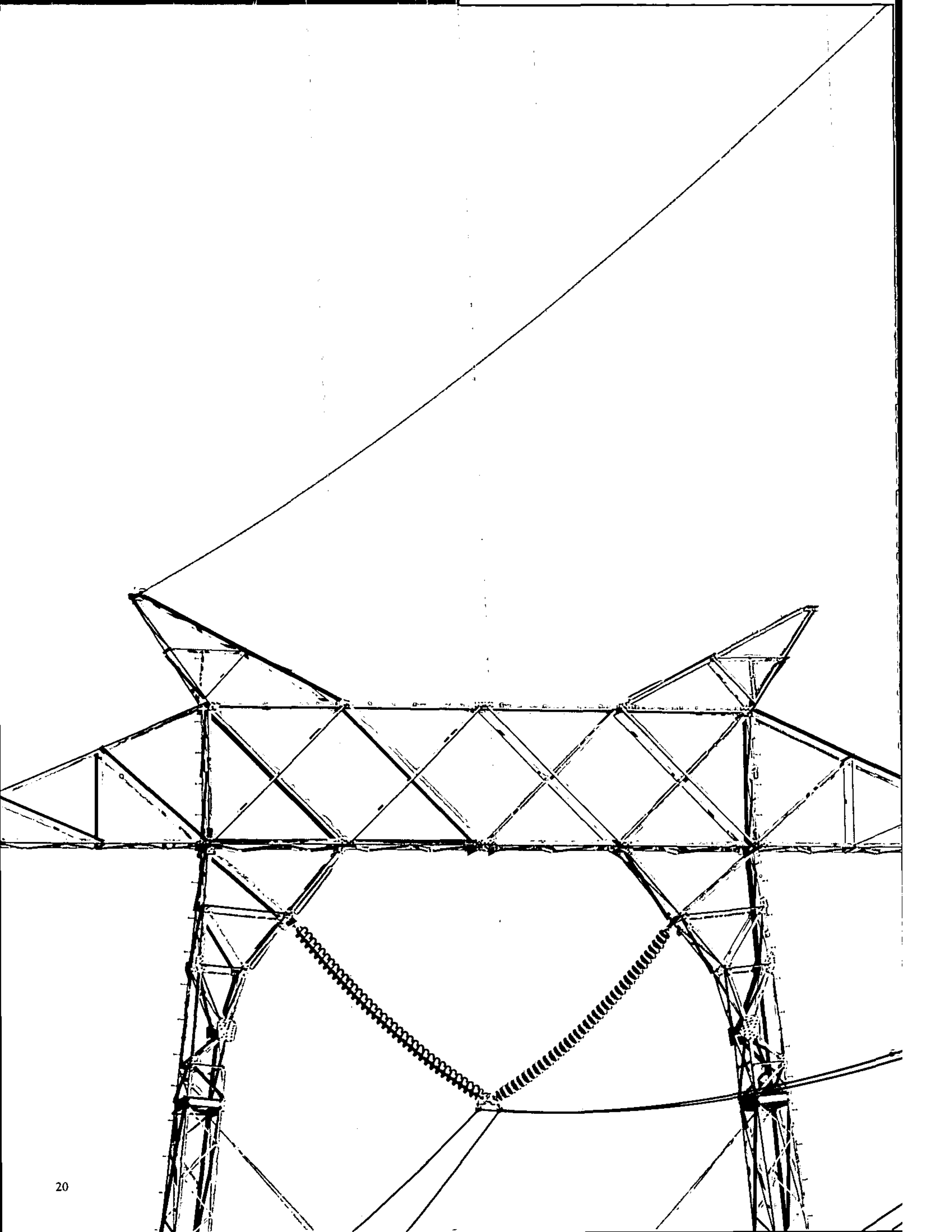
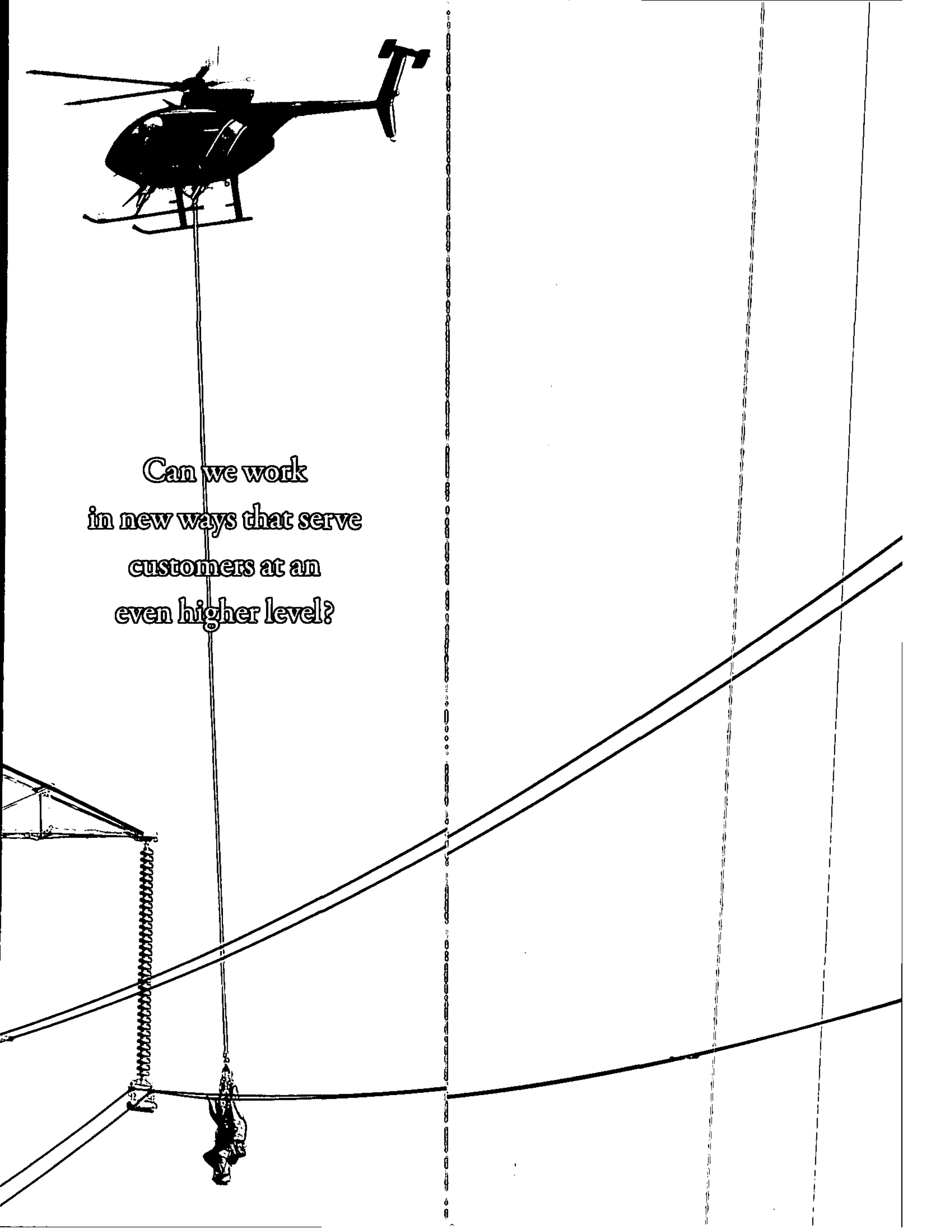
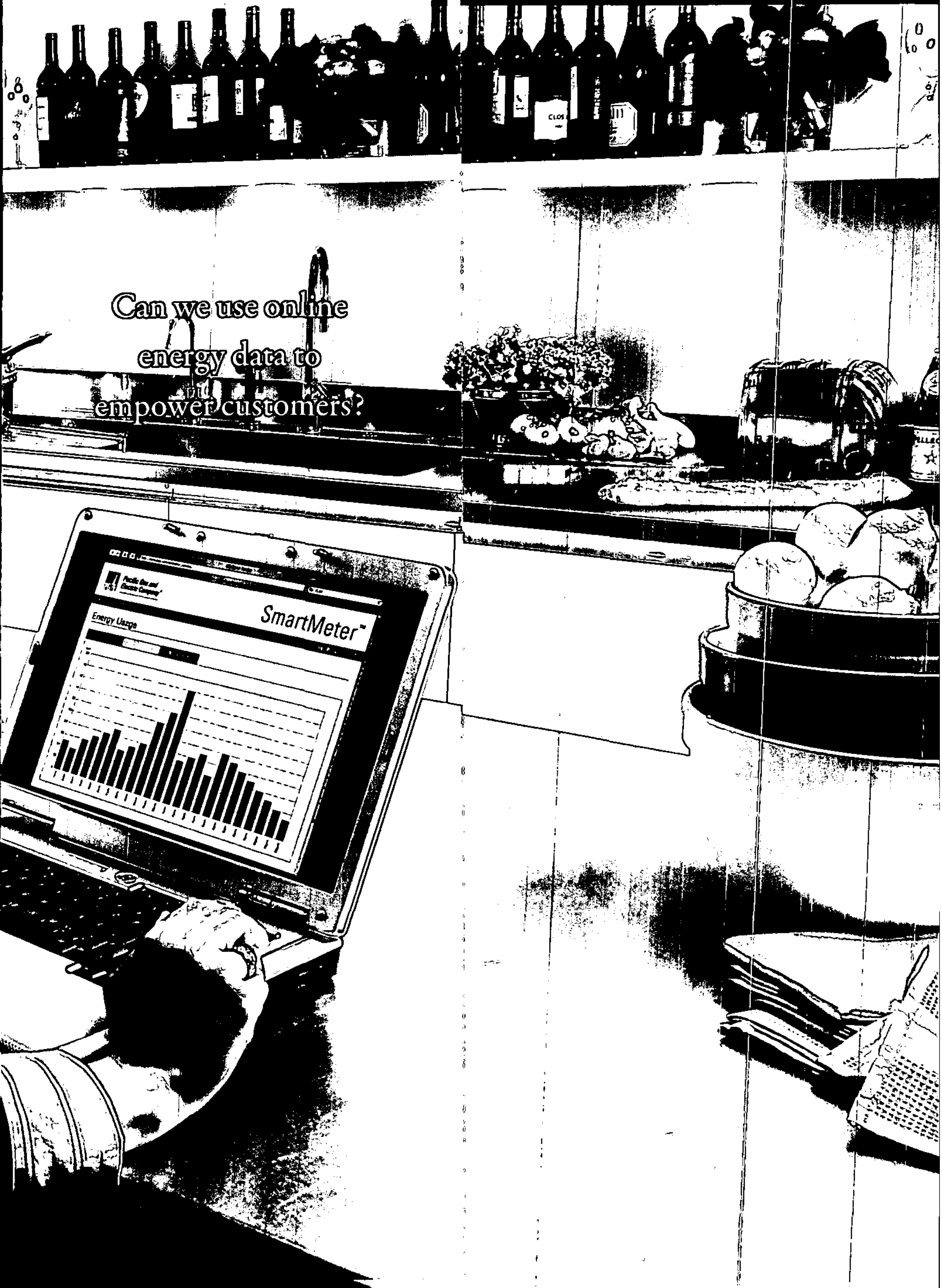
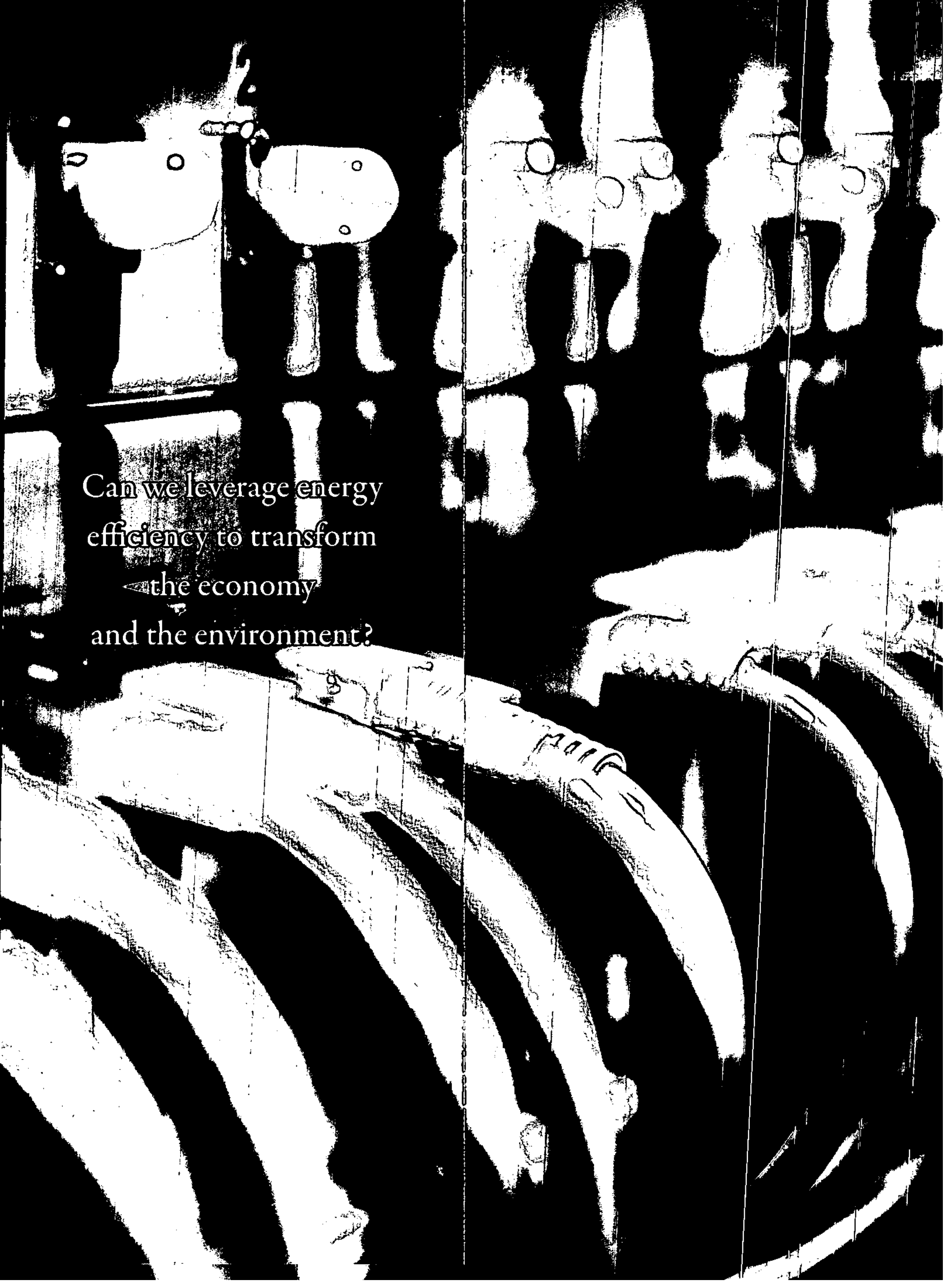

Can we
slow global climate
change?


Can we build
energy sustainability into
our communities?



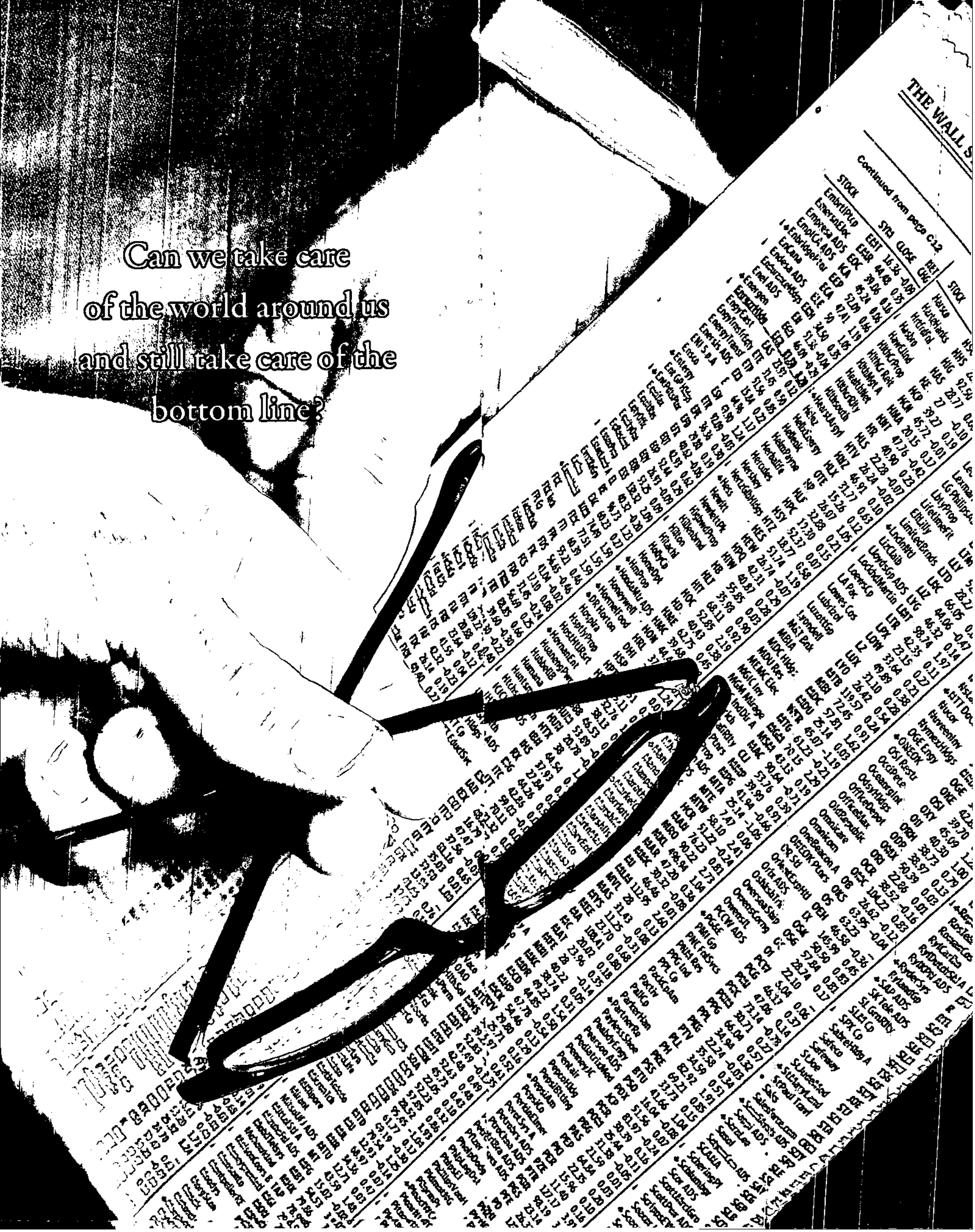

Can we work
in new ways that serve
customers at an
even higher level?


Can we use online
energy data to
empower customers?
SmartMeter™
Energy Usage


Can we leverage energy
efficiency to transform
the economy
and the environment?

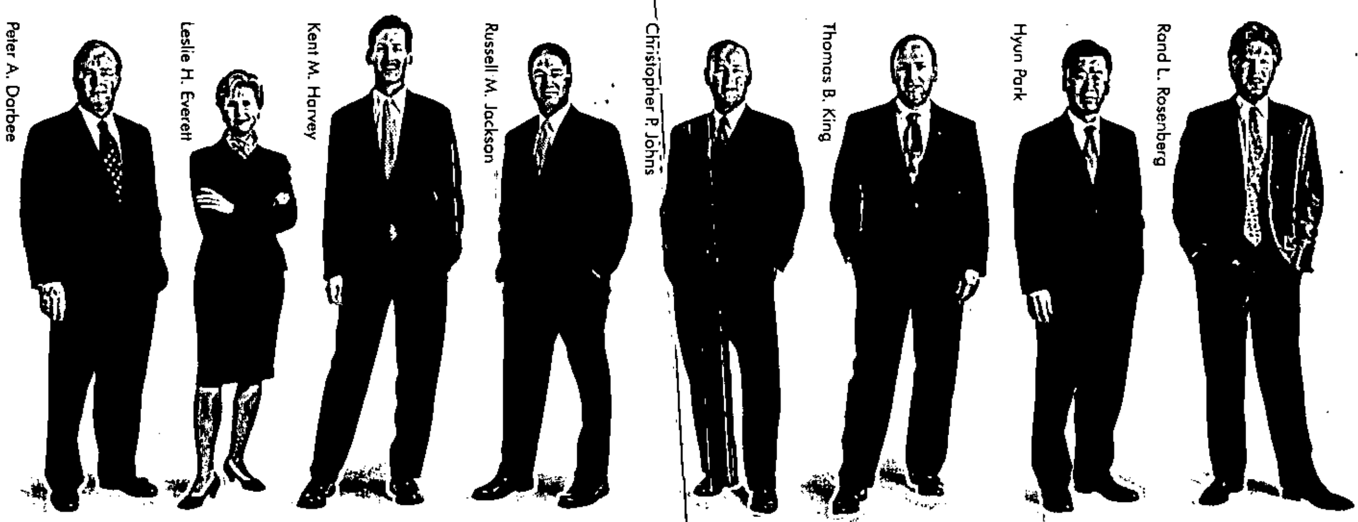
Can we engage everyone at PG&E as a community volunteer?


Can we harness
new forms of renewable
energy?


Can we take care
of the world around us
and still take care of the
bottom line?

A COMPANY POWERED BY PEOPLE

PG&E derives its energy from the 20,000 employees who have dedicated their professional lives to serving our enterprise as well as California's communities. Our world-class leadership team is just as determined and dynamic – a blend that mixes specialized utility experience and expertise with diverse skills and talents sharpened in other industries. Our leaders are also driven and compete hard to find creative solutions and strategies that will serve customers better today and tomorrow. They understand that talent and tenacity are nothing without also embracing values such as integrity, accountability, and a commitment



PETER A. DARBEE
PG&E Corporation – Chairman of the Board, Chief Executive Officer, and President
Pacific Gas and Electric Company – Chairman of the Board

Since taking the helm at PG&E two years ago, Peter Darbee has set the company's sights on becoming the leading utility in the United States. As a veteran of the energy, telecommunications and investment banking industries, Peter has built a record of success in both regulated and non-regulated markets and in industries that have undergone substantial change. He is applying that experience today at PG&E. He is intent on transforming the company with a focus on delighting its 15 million customers, energizing its 20,000 employees and rewarding each of its shareholders. Peter has been with the company for seven years.

LESLIE H. EVERETT
PG&E Corporation – Senior Vice President, Communications and Public Affairs

Leslie Everett is responsible for governmental relations, corporate environmental and federal affairs, federal governmental relations, corporate communications, civic partnership and community initiatives, and corporate governance and the office of the corporate secretary. She is also President of the PG&E Corporation Foundation for charitable giving. Leslie has been with the company for 29 years.

KENT M. HARVEY
PG&E Corporation – Senior Vice President and Chief Risk and Audit Officer

Kent Harvey oversees the company's enterprise-wide risk management, internal audit, compliance and corporate security functions. During his career, he has held a variety of financial positions. Kent has been with the company for 24 years.

RUSSELL M. JACKSON
PG&E Corporation – Senior Vice President, Human Resources
Pacific Gas and Electric Company – Senior Vice President, Human Resources

Russ Jackson is responsible for the policies governing human resources and provides strategic oversight in the areas of compensation, benefits, labor relations, staffing and leadership development for both the holding company and the utility, which together employ more than 20,000 people. Russ has been with the company for 26 years.

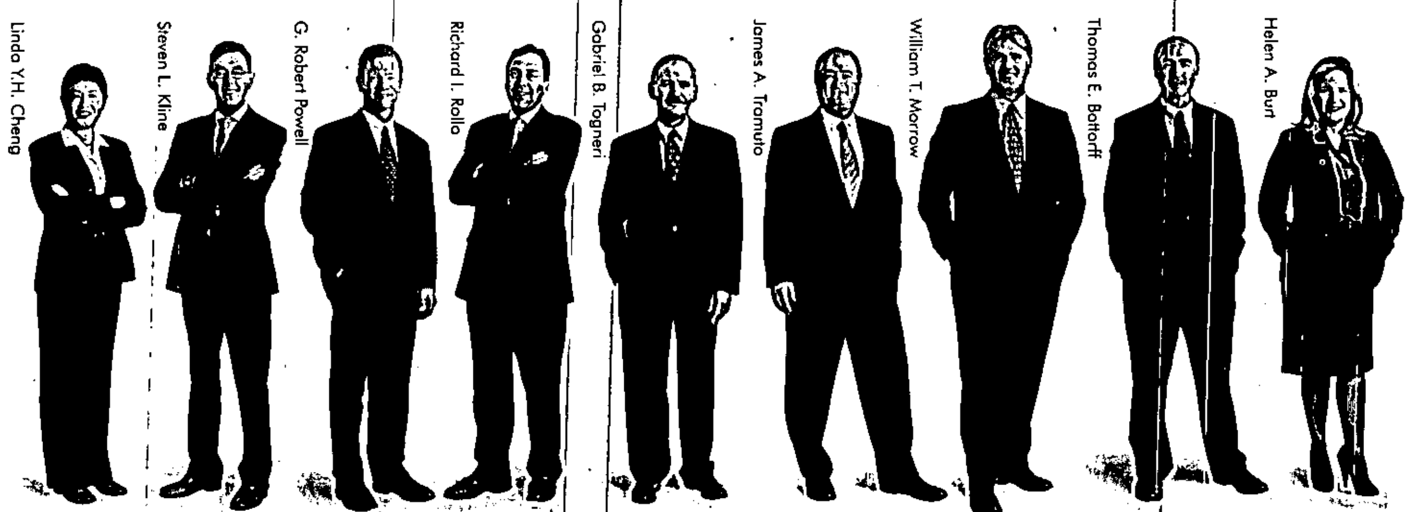
CHRISTOPHER P. JOHNS
PG&E Corporation – Senior Vice President, Chief Financial Officer, and Treasurer
Pacific Gas and Electric Company – Senior Vice President, Chief Financial Officer, and Treasurer

Chris Johns oversees the financial activities of the $34 billion company including accounting, treasury, tax, business and financial planning, and investor relations. Before joining PG&E Corporation, he was a partner at KPMG Peat Marwick LLP. Chris has been with the company for 10 years.

THOMAS B. KING
PG&E Corporation – Senior Vice President
Pacific Gas and Electric Company – Chief Executive Officer

Tom King is the CEO of our utility business. Tom plays a key role in growing PG&E

to excellence. Our leaders also know that collaboration is crucial – at all levels of our organization. And they help bring people together to pursue a common vision. PG&E shines brightly, but it's a corporate constellation, not a collection of stars. The leaders pictured here embody growth in all its manifestations – whether it's expanding one of our manager's professional horizons, delivering quality-of-life improvements to customers, providing economic opportunity to our communities, or enhancing shareholder value. Looking ahead, this leadership team will continue to listen and learn wherever and whenever it can. In the end, that is the best – and only – way to delight customers.



Corporation's business, including potential strategic growth opportunities. He has more than 20 years of experience in the energy industry. Tom has been with the company for nine years.

HYUN PARK
PG&E Corporation – Senior Vice President and General Counsel
Hyun Park is responsible for leading and directing the legal function for PG&E Corporation and its businesses, including its principal subsidiary, Pacific Gas and Electric Company. Prior to joining PG&E Corporation, he was Vice President, General Counsel and Secretary at Allegheny Energy, Inc., in Greensburg, PA. Hyun joined the company in November 2006.

RAND L. ROSENBERG
PG&E Corporation –
Senior Vice President, Corporate Strategy and Development
Rand Rosenberg is responsible for developing PG&E Corporation's strategic plan and overseeing the company's corporate development efforts in regard to mergers and acquisitions. Rand joined the company in 2005 after having spent over a decade in the field of investment banking.

LINDA Y.H. CHENG
PG&E Corporation – Vice President, Corporate Governance and Corporate Secretary
Pacific Gas and Electric Company – Vice President, Corporate Governance and Corporate Secretary
Linda Cheng is responsible for managing corporate governance matters and the corporate secretary functions for PG&E Corporation and its utility unit, Pacific Gas and Electric Company. She joined the company as an attorney and became Corporate Secretary for both companies in 2001. Linda has been with the company for 17 years.

STEVEN L. KLINE
PG&E Corporation –
Vice President, Corporate Environmental and Federal Affairs
Steve Kline is responsible for environmental policy activities at the company. He also has oversight of the company's Washington, D.C. office and serves as the senior liaison with federal elected and regulatory officials. For more than two decades, he has actively sought public policies that encourage energy efficiency and sound environmental policies and practices. Steve has been with the company for 27 years.

G. ROBERT POWELL
PG&E Corporation –
Vice President and Controller
Pacific Gas and Electric Company –
Vice President and Controller
Bob Powell joined PG&E Corporation from PricewaterhouseCoopers, where he was a partner in the audit and business assurance group within the firm's National Utility Practice. Prior to this he served in the Atlanta office of Arthur Andersen LLP as a partner in the energy and communications practice. Bob joined the company in October 2005.

RICHARD I. ROLLO
PG&E Corporation –
Vice President, Strategic Development and Business Integration
Richard Rollo has worked in investment banking and corporate development for more than 20 years, identifying, analyzing and executing future growth opportu-

nities. At PG&E Corporation, he focuses on mergers, acquisitions and business integration within the evolving regulated utility industry. Richard joined the company in March 2006.

GABRIEL B. TOGNERI
PG&E Corporation –
Vice President, Investor Relations
Gabe Togneri provides the investment community, PG&E shareholders and investment analysts with information about the Corporation, its financial performance, and future outlook. He has served in a number of positions in energy and finance. Gabe has been with the company for 29 years.

JAMES A. TRAMUTO
PG&E Corporation – Vice President, Federal Governmental Relations
Jim Tramuto has more than 35 years of experience working in the energy industry and governmental relations. Prior to joining the company, Jim was President of TECO Gas Marketing, President and CEO of Polaris Pipeline, and held a number of executive, legal, and governmental affairs positions at United Gas Pipeline Company. Jim has been with the company for 14 years.

WILLIAM T. MORROW
Pacific Gas and Electric Company – President and Chief Operating Officer
Bill Morrow is responsible for overall management of the utility's day-to-day operations. Prior to joining PG&E, Bill held various CEO and President roles including President of Japan Telecom, CEO of Vodafone UK, President of Vodafone KK, and, most recently, CEO of Vodafone Europe. He is well known for his ability to lead large-scale performance improvements and turnarounds. Bill began his career at AT&T (formerly Pacific Telephone) in 1980. Bill joined the company in August 2006.

THOMAS E. BOTTORFF
Pacific Gas and Electric Company – Senior Vice President, Regulatory Relations
Tom Bottorff is responsible for developing, coordinating and managing policy with state and regulatory agencies, including the California Public Utilities Commission (CPUC), the Federal Energy Regulatory Commission (FERC) and the Independent System Operator. He also is responsible for developing and filing rate proposals with the CPUC and FERC, and overseeing the company's gas and electric tariffs. Tom has been with the company for 24 years.

HELEN A. BURT
Pacific Gas and Electric Company – Senior Vice President and Chief Customer Officer
Helen Burt is responsible for developing and implementing customer-centered, enterprise-wide business strategies to create customer experiences that will help define PG&E as a leading utility. She has more than 25 years of customer service experience within the utility industry. Helen joined the company in February 2006.

JEFFREY D. BUTLER
Pacific Gas and Electric Company – Senior Vice President, Energy Delivery
Jeff Butler oversees the operation, maintenance and construction, as well as engineering, of the utility's gas and electric transmission and distribution systems. Jeff has been with the company for 27 years.

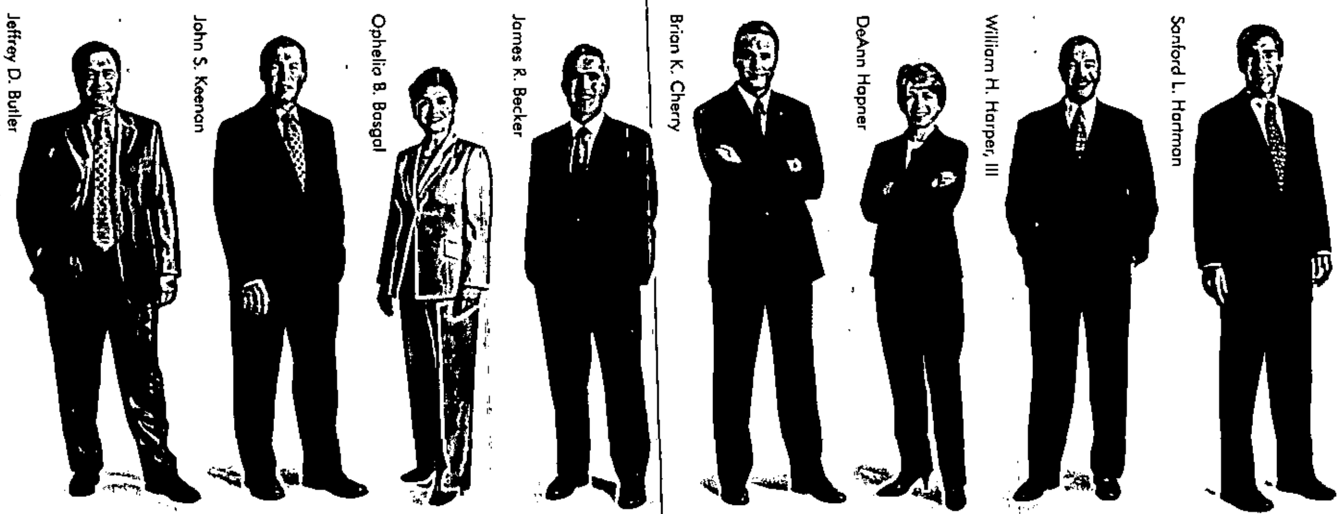
JOHN S. KEENAN
Pacific Gas and Electric Company – Senior Vice President, Generation and Chief Nuclear Officer
Jack Keenan is responsible for all of the company's power generation assets, including nuclear, fossil and hydroelectric. He also manages the strategic direction and financial success of those assets, as well as that of the company's cogeneration and renewable energy sources. He has more than three decades of power-generation experience. Jack joined the company one year ago.

OPHELIA B. BASGAL
Pacific Gas and Electric Company – Vice President, Civic Partnership and Community Initiatives
Ophelia Basgal manages the company's charitable contributions, employee and retiree volunteerism, and community engagement programs. She is a nationally recognized expert on housing community development issues, having served for 27 years as executive director of the Alameda County Housing Authority. Ophelia joined the company in September 2005.

JAMES R. BECKER
Pacific Gas and Electric Company – Vice President, Diablo Canyon Power Plant Operations and Station Director
Jim Becker leads all operations, maintenance, licensing and plant training activities for the Diablo Canyon Power Plant. Jim also oversees the periodic refueling of the plant's two power generation units. He has held a series of positions of increasing responsibility within the nuclear generation group. Jim has been with the company for 24 years.

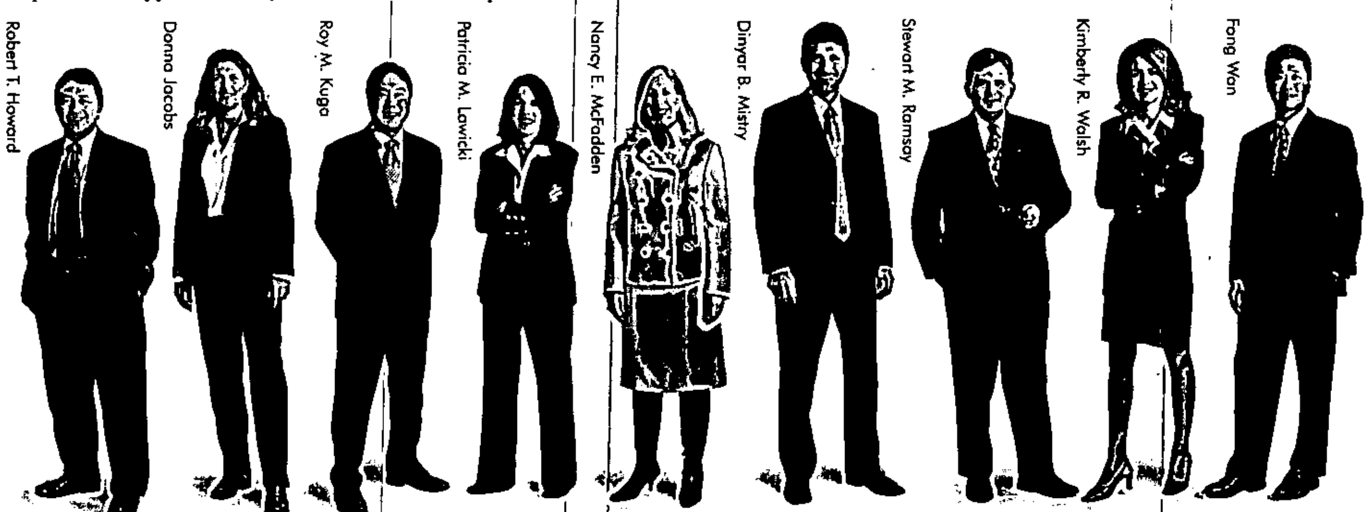
BRIAN K. CHERRY
Pacific Gas and Electric Company – Vice President, Regulatory Relations
Brian Cherry serves as the company's primary liaison with the California Public Utilities Commission and has more than 20 years of experience in the California energy regulatory arena. He worked with Southern California Gas Company and Sempra Energy prior to joining PG&E. Brian has been with the company for six years.

DEANN HAPNER
Pacific Gas and Electric Company – Vice President, FERC and ISO Relations
Dede Hapner is responsible for developing, coordinating and



managing policy and relations with the Federal Energy Regulatory Commission and the Independent System Operator. She works with the federal agencies that regulate high-voltage transmission, interstate pipelines, hydro facilities and the western U.S. energy markets. Dede has been with the company for 21 years.

WILLIAM H. HARPER, III
Pacific Gas and Electric Company – Vice President, Strategic Sourcing and Operations Support
Bill Harper oversees the utility's supply chain, sourcing, materials operations, supplier diversity,



transportation services, corporate real estate, environmental services, and safety, health and claims. He has more than two decades of experience leading procurement and sourcing initiatives. Bill joined the company in August 2006.

SANFORD L. HARTMAN
Pacific Gas and Electric Company – Vice President and Managing Director, Law
Sandy Hartman manages the Law department serving both Pacific Gas and Electric Company and its holding company, PG&E Corporation. He has more than 20 years of legal experience in the field of energy. Sandy has been with the company for 17 years.

ROBERT T. HOWARD
Pacific Gas and Electric Company – Vice President, Gas Transmission and Distribution
Bob Howard is responsible for overseeing the utility's 47,000-mile natural gas transmission and distribution system. He joined Pacific Gas and Electric Company after spending 14 years with Gas Transmission Northwest (GTN), a subsidiary of National Energy and Gas Transmission, formerly a PG&E Corporation subsidiary. Bob has been with the utility for two years.

DONNA JACOBS
Pacific Gas and Electric Company – Vice President, Nuclear Services
Donna Jacobs is responsible for engineering, strategic projects, security, emergency planning, and materials procurement at the Diablo Canyon Power Plant, as well as geosciences for all company assets. Prior to joining the company, Donna was Vice President and Plant Manager for the Wolf Creek Nuclear Operating Corporation in Burlington, Kansas. Donna has been with the company for two years.

ROY M. KUGA
Pacific Gas and Electric Company – Vice President, Energy Supply
Roy Kuga ensures that PG&E customers' demands for electricity and natural gas are met through a reliable, competitively priced portfolio of environmentally friendly and fuel efficient resources. Roy has been with the company for 27 years.

PATRICIA M. LAWICKI
Pacific Gas and Electric Company – Vice President and Chief Information Officer
Pat Lawicki has more than 25 years in the information technology field. She is evaluating every aspect of the company's IT business and is developing the technology strategy and architecture for the company's business transformation initiatives. Pat has been with the company for two years.

NANCY E. MCFADDEN
Pacific Gas and Electric Company – Vice President, Governmental Relations
Nancy McFadden has spent nearly 20 years in law, policy and politics and manages the company's public policy relationships with elected officials throughout California. Previously, she was deputy chief of staff to Vice President Al Gore, advisor to Governor Gray Davis, and practiced law at O'Melveny and Myers. Nancy joined the company in September 2005.

DINYAR B. MISTRY
Pacific Gas and Electric Company – Vice President, State Regulation
Dinyar Mistry is responsible for all state-jurisdictional revenue requirement matters and all tariff and rates issues. Since joining the company, he has held positions of increasing responsibility in the finance, treasury and accounting organizations at the utility and PG&E Corporation. Dinyar has been with the company for 12 years.

STEWART M. RAMSAY
Pacific Gas and Electric Company – Vice President, Asset Management and Electric Transmission
Stewart Ramsay formulates strategy for PG&E's electric transmission business, and oversees the planning of performance improvements to the company's gas and electric systems. He has more than 25 years of experience in the power sector, working with utilities throughout the world. Stewart joined the company in January 2005.

KIMBERLY R. WALSH
Pacific Gas and Electric Company – Vice President, Communications
Kim Walsh oversees media relations, internal communications, customer communications, and advertising. She brings more than 18 years of experience in high-level communications roles in government and public relations. Kim has been with the company for seven years.

FONG WAN
Pacific Gas and Electric Company – Vice President, Energy Procurement
Fong Wan oversees gas and electric supply planning and policies, market assessment and quantitative analysis, supply development, procurement and settlement. He joined the company as a financial analyst and has since held positions of increasing responsibility. Fong has been with the company for 17 years.

PG&E CORPORATION AND
PACIFIC GAS AND ELECTRIC COMPANY
FINANCIAL STATEMENTS

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FINANCIAL HIGHLIGHTS
PG&E Corporation

(unaudited, in millions, except share and per share amounts)	2006	2005
Operating Revenues	$ 12,539	$ 11,703
Net Income		
Earnings from operations(1)	922	906
Items impacting comparability(2)	69	(2)
NEGT	–	13
Reported consolidated net income	991	917
Income Per Common Share, diluted		
Earnings from operations(1)	2.57	2.34
Items impacting comparability(2)	0.19	–
NEGT	–	0.03
Reported consolidated net earnings per common share, diluted	2.76	2.37
Dividends Declared Per Common Share	1.32	1.23
Total Assets at December 31,	34,803	34,074
Number of common shareholders at December 31,	93,170	98,252
Number of common shares outstanding at December 31,(3)	374,181,059	368,268,502

(1) Earnings from operations does not meet the guidelines of accounting principles generally accepted in the United States of America, or GAAP. It should not be considered an alternative to net income. It reflects net income of PG&E Corporation, on a stand-alone basis, and the Utility, but excludes items impacting comparability, in order to provide a measure that allows investors to compare the core underlying financial performance of the business from one period to another, exclusive of items that management believes do not reflect the normal course of operations.

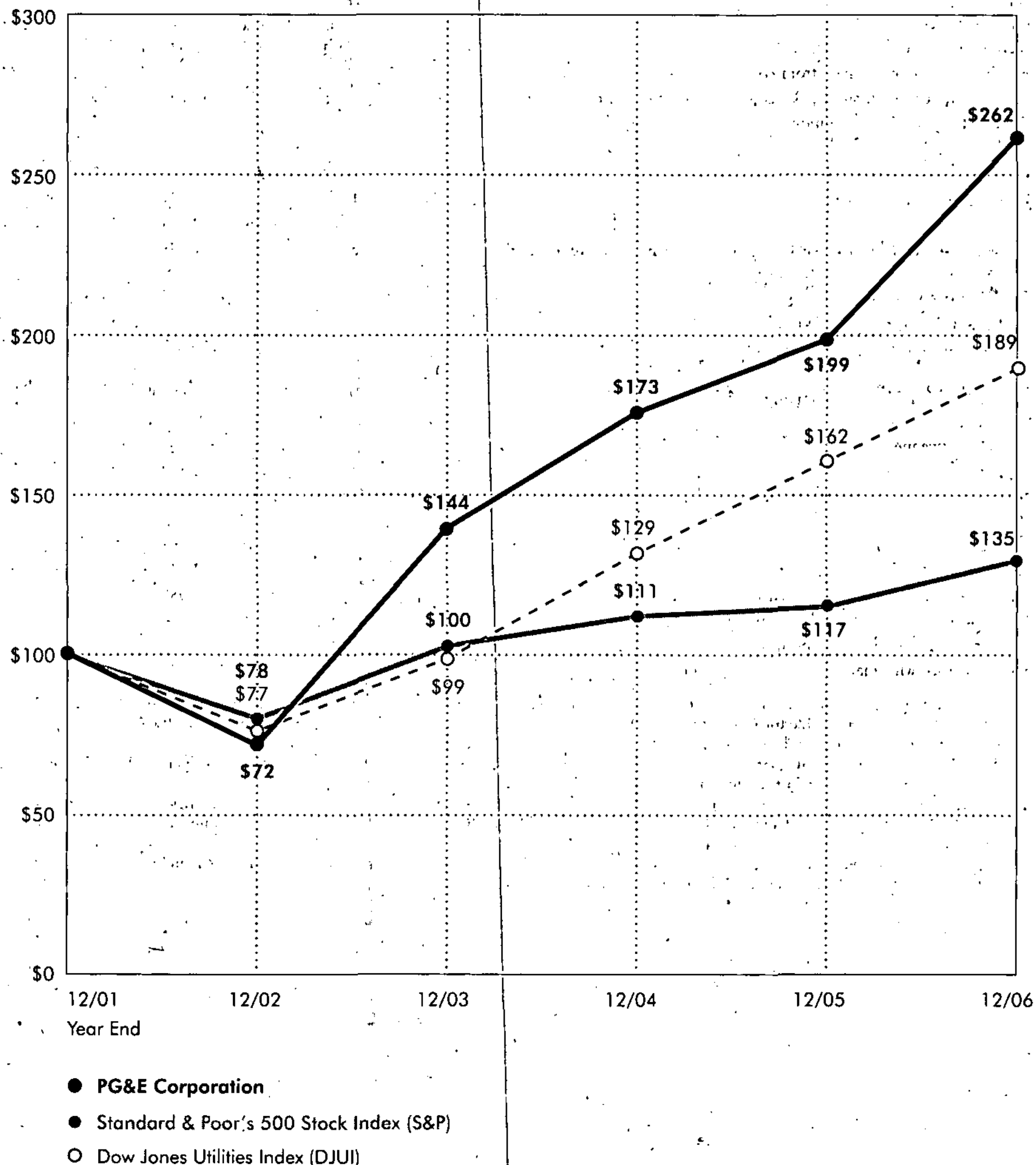
(2) Items impacting comparability represent items that management does not believe are reflective of normal, core operations.
Items impacting comparability for 2006 include:
- The recovery of approximately $77 million ($0.21 per common share), after-tax, of Scheduling Coordinator, or SC, costs, incurred from April 1998 through September 2006, based on a Federal Energy Regulatory Commission, or FERC, order;
- An increase of approximately $18 million ($0.05 per common share), after-tax, in the estimated cost of environmental remediation associated with the Utility's gas compressor station located near Hinkley, California, as a result of changes in the California Regional Water Quality Control Board's imposed remediation levels;
- The recovery of approximately $28 million ($0.08 per common share), after-tax, of previously recorded net interest expense on the Power Exchange Corporation, or PX, liability from April 12, 2004 to February 10, 2005, in the Energy Recovery Bond Balancing Account as a result of completion of the verification audit by the CPUC in the Utility's 2005 annual electric true-up proceeding; and
- Severance costs of approximately $18 million ($0.05 per shares), after-tax, to reflect consolidation of various positions in connection with the Utility's continued effort to streamline processes and achieve costs and operating efficiencies through implementation of various initiatives.

Items impacting comparability for 2005 include:
- The net effect of incremental interest costs of approximately $3 million ($0.01 per share), after-tax, incurred by the Utility through February 10, 2005 related to generator disputed claims in the Utility's Chapter 11 proceeding, which are not considered recoverable;
- Annual Earnings Assessment Proceeding revenues of approximately $93 million ($0.24 per share), after-tax, as a result of an October 27, 2005 CPUC decision allowing the Utility to recover shareholder incentives for successful implementation for certain public purpose programs; and
- An additional accrual of $91 million ($0.23 per share), after-tax, to reflect both the February 3, 2006 settlement of most of the claims in the "Chromium Litigation" pending against the Utility and an accrual for the remaining unresolved claims.

(3) The common shares outstanding include 24,665,500 shares at December 31, 2006, and December 31, 2005, held by a wholly owned subsidiary of PG&E Corporation. These shares are accounted for as a reduction of outstanding shares in the Consolidated Financial Statements.

COMPARISON OF FIVE-YEAR CUMULATIVE TOTAL SHAREHOLDER RETURN[1]

This graph compares the cumulative total return on PG&E Corporation common stock (equal to dividends plus stock price appreciation) during the past five fiscal years with that of the Standard & Poor's Stock Index and the Dow Jones Utilities Index.



(1) Assumes $100 invested on December 31, 2001, in PG&E Corporation common stock, the Standard & Poor's 500 Stock Index, and the Dow Jones Utilities Index, and assumes quarterly reinvestment of dividends. The total shareholder returns shown are not necessarily indicative of future returns.

SELECTED FINANCIAL DATA

(in millions, except per share amounts)	2006	2005	2004[1]	2003	2002
PG&E Corporation[2]					
For the Year					
Operating revenues	**$12,539**	$11,703	$11,080	$10,435	$10,505
Operating income	**2,108**	1,970	7,118	2,343	3,954
Income from continuing operations	**991**	904	3,820	791	1,723
Earnings per common share from continuing operations, basic	**2.78**	2.37	9.16	1.96	4.53
Earnings per common share from continuing operations, diluted	**2.76**	2.34	8.97	1.92	4.49
Dividends declared per common share[3]	**1.32**	1.23	–	–	–
At Year-End					
Book value per common share[4]	**$ 21.24**	$ 19.94	$ 20.90	$ 10.16	$ 8.92
Common stock price per share	**47.33**	37.12	33.28	27.77	13.90
Total assets	**34,803**	34,074	34,540	30,175	36,081
Long-term debt (excluding current portion)	**6,697**	6,976	7,323	3,314	3,715
Rate reduction bonds (excluding current portion)	**–**	290	580	870	1,160
Energy recovery bonds (excluding current portion)	**1,936**	2,276	–	–	–
Financial debt subject to compromise	**–**	–	–	5,603	5,605
Preferred stock of subsidiary with mandatory redemption provisions	**–**	–	122	137	137
Pacific Gas and Electric Company					
For the Year					
Operating revenues	**$12,539**	$11,704	$11,080	$10,438	$10,514
Operating income	**2,115**	1,970	7,144	2,339	3,913
Income available for common stock	**971**	918	3,961	901	1,794
At Year-End					
Total assets	**$34,371**	$33,783	$34,302	$29,066	$27,593
Long-term debt (excluding current portion)	**6,697**	6,696	7,043	2,431	2,739
Rate reduction bonds (excluding current portion)	**–**	290	580	870	1,160
Energy recovery bonds (excluding current portion)	**1,936**	2,276	–	–	–
Financial debt subject to compromise	**–**	–	–	5,603	5,605
Preferred stock with mandatory redemption provisions	**–**	–	122	137	137

(1) Financial data reflects the recognition of regulatory assets provided under the December 19, 2003 settlement agreement entered into among PG&E Corporation, Pacific Gas and Electric Company and the California Public Utilities Commission to resolve Pacific Gas and Electric Company's proceeding under Chapter 11 of the U.S. Bankruptcy Code.

(2) Matters relating to discontinued operations are discussed in Management's Discussion and Analysis of Financial Condition and Results of Operations and in the Notes to the Consolidated Financial Statements.

(3) The Board of Directors of PG&E Corporation declared a cash dividend of $0.30 per share per quarter for the first three quarters of 2005. In the fourth quarter of 2005, the quarterly cash dividend declared was increased to $0.33 per share. See Note 8 of the Notes to the Consolidated Financial Statements for further discussion.

(4) Book value per common share includes the effect of participating securities. The dilutive effect of outstanding stock options and restricted stock are further disclosed in the Notes to the Consolidated Financial Statements.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

OVERVIEW

PG&E Corporation, incorporated in California in 1995, is a company whose primary purpose is to hold interests in energy-based businesses. The company conducts its business principally through Pacific Gas and Electric Company, or the Utility, a public utility operating in northern and central California. The Utility engages primarily in the businesses of electricity and natural gas distribution, electricity generation, procurement and transmission, and natural gas procurement, transportation and storage. PG&E Corporation became the holding company of the Utility and its subsidiaries on January 1, 1997. Both PG&E Corporation and the Utility are headquartered in San Francisco, California.

The Utility served approximately 5.1 million electricity distribution customers and approximately 4.2 million natural gas distribution customers at December 31, 2006. The Utility had approximately $34.4 billion in assets at December 31, 2006, and generated revenues of approximately $12.5 billion in 2006.

The Utility is regulated primarily by the California Public Utilities Commission, or CPUC, and the Federal Energy Regulatory Commission, or FERC. The Utility generates revenues mainly through the sale and delivery of electricity and natural gas at rates set by the CPUC and the FERC. Rates are set to permit the Utility to recover its authorized "revenue requirements" from customers. Revenue requirements are designed to allow the Utility an opportunity to recover its reasonable costs of providing utility services, including a return of, and a fair rate of return on, its investment in utility facilities, or rate base. Changes in any individual revenue requirement affect customers' rates and could affect the Utility's revenues.

Through October 29, 2004, PG&E Corporation also owned National Energy & Gas Transmission, Inc., or NEGT, formerly known as PG&E National Energy Group, Inc., which engaged in electricity generation and natural gas transportation in the United States and which is accounted for as discontinued operations in PG&E Corporation's financial statements, as discussed in Note 7 of the Notes to the Consolidated Financial Statements.

This is a combined annual report of PG&E Corporation and the Utility and includes separate Consolidated Financial Statements for each of these two entities. PG&E Corporation's Consolidated Financial Statements include the accounts of PG&E Corporation, the Utility and other wholly owned and controlled subsidiaries. The Utility's Consolidated Financial Statements include the accounts of the Utility and its wholly owned and controlled subsidiaries. This combined Management's Discussion and Analysis of Financial Condition and Results of Operations, or MD&A, should be read in conjunction with the Consolidated Financial Statements and Notes to the Consolidated Financial Statements included in this annual report.

SUMMARY OF CHANGES IN EARNINGS PER COMMON SHARE AND NET INCOME FOR 2006

PG&E Corporation's diluted earnings per common share, or EPS, for 2006 was $2.76 per share, compared to $2.37 per share in 2005. The increase in diluted EPS for 2006 is primarily due to the FERC's approval of recovery of certain costs the Utility began incurring in 1998 in its capacity as scheduling coordinator, or SC, for its existing wholesale electricity transmission customers, increased gas transmission revenues, fewer litigation settlements, utilization of tax benefits associated with prior capital losses, and a lower number of shares outstanding following the November 2005 repurchase of 31,650,300 shares of PG&E Corporation common stock. These increases in earnings per share were partially offset by the credit the Utility began to provide to customers after the November 2005 issuance of the second series of energy recovery bonds, or ERBs. (For a discussion of the ERBs and this credit, see "Electric Operating Revenues" below and Notes 3 and 6 of the Notes to the Consolidated Financial Statements.)

For 2006, PG&E Corporation's net income increased by $74 million, or 8%, to $991 million, compared to $917 million in 2005. This increase reflects the recognition of recovery of SC costs in 2006 that resulted in an increase to net income of approximately $77 million compared to 2005. Increases in net income associated with gas transmission revenues, fewer litigation settlements and utilization of tax benefits associated with prior capital losses were offset by the carrying cost credit associated with the second series of ERBs and other factors.

KEY FACTORS AFFECTING RESULTS OF OPERATIONS AND FINANCIAL CONDITION

PG&E Corporation's and the Utility's results of operations and financial condition depend primarily on whether the Utility is able to operate its business within authorized revenue requirements which, in part, depend on management's ability to accurately forecast future costs incurred in providing utility service, timely recover its authorized costs, and earn its authorized rate of return. Several factors have had, or are expected to have, a significant impact on PG&E Corporation's and the Utility's results of operations and financial condition, including:

- **The Outcome of Regulatory Proceedings** — The amount of the Utility's revenues and the amount of costs the Utility is authorized to recover from customers are primarily determined through regulatory proceedings. The timing of CPUC and FERC decisions affect when the Utility is able to record the authorized revenues. As described above, the FERC's decision in 2006 to allow the Utility to recover SC costs had a material effect on PG&E Corporation's and the Utility's results of operations. The outcome of various other regulatory proceedings, including the Utility's 2007 General Rate Case, or GRC, also will have a material effect. In the 2007 GRC, the CPUC will determine the amount of the Utility's authorized base revenues for the period 2007 through 2010. The Utility has requested the CPUC to approve a settlement agreement reached in the Utility's 2007 GRC. The proposed revenue requirement provided in the settlement agreement reflects an increase of $222 million in the Utility's electric distribution revenues, an increase of $21 million in gas distribution revenues, and a decrease of $30 million in generation operation revenues for an overall increase of $213 million over the authorized 2006 amounts. The settlement agreement also includes revenue increases for 2008, 2009 and 2010. The revenue requirements authorized in the 2007 GRC will be effective as of January 1, 2007. On February 13, 2007 a proposed decision and an alternate proposed decision were issued in the 2007 GRC. (See further discussion under "Regulatory Matters" below.)
- **Capital Structure** — The Utility's 2006 and 2007 authorized capital structure includes a 52% equity component. For 2006 and 2007, the Utility is authorized to earn a rate of return on equity, or ROE, of 11.35% on its electricity and natural gas distribution and electricity generation rate base. The CPUC will conduct a new cost of capital proceeding to set the Utility's authorized capital structure and rates of return for 2008. The Utility is required to file its 2008 cost of capital application by May 8, 2007.
- **The Success of the Utility's Strategy to Achieve Operational Excellence and Improved Customer Service** — During 2006, the Utility continued to undertake various initiatives to implement changes to its business processes and systems in an effort to provide better, faster and more cost-effective service to its customers. During 2006, the Utility incurred approximately $137 million, including approximately $36 million for employee severance costs, to implement these initiatives. The Utility intends to incur similar costs of approximately $200 million for further implementation of these initiatives in 2007. The proposed amounts of the revenue requirement increases for 2008, 2009 and 2010 included in the proposed 2007 GRC settlement agreement are expected to be adequate in light of the estimated cost savings anticipated to be realized from implementation of these initiatives. If the actual cost savings are greater than anticipated, such benefits would accrue to shareholders. Conversely, if these cost savings are not realized, earnings available for shareholders would be reduced.

- **The Amount and Timing of Capital Expenditures** — In 2006, the CPUC authorized the Utility to make substantial capital expenditures in connection with the construction of new generation facilities estimated to become operational beginning in 2009 and 2010, and the installation of an advanced metering system. In addition, the Utility has requested regulatory approval for various capital expenditures to fund investments in transmission and distribution infrastructure needed to serve its customers (i.e., to extend the life of existing infrastructure, to replace existing infrastructure and to add new infrastructure to meet already authorized growth). The amount and timing of the Utility's capital expenditures will affect the amount of rate base on which the Utility may earn its authorized ROE. If the CPUC disallowed the Utility from recovering any portion of its capital expenditures from customers, the Utility would be unable to earn a ROE on the disallowed amount. (See further discussion under "Capital Expenditures" below.)
- **Changes in Environmental Liabilities and the Outcome of Litigation** — The Utility's operations are subject to extensive federal, state and local environmental laws and permits. Complying with these environmental laws has in the past required significant expenditures for environmental compliance, monitoring and pollution control equipment, as well as for related fees and permits. During 2006, the Utility increased its recorded liability for environmental remediation by $74 million. In addition, during 2006, the Utility paid approximately $295 million to settle a majority of claims relating to alleged exposure to chromium at the Utility's natural gas compressor stations. (See discussion under "Environmental Matters" below and Note 17 of the Notes to Consolidated Financial Statements.)
- **Impact of the Utility's Chapter 11 Reorganization** — The Utility's plan of reorganization under Chapter 11 of the U.S. Bankruptcy Code became effective on April 12, 2004. The plan of reorganization incorporated the terms of a settlement agreement among the CPUC, PG&E Corporation and the Utility, referred to as the Chapter 11 Settlement Agreement. During 2005, the Utility issued two series of ERBs. The first series was issued to refinance the after-tax portion of the settlement regulatory asset established under the Chapter 11 Settlement Agreement. The second series was issued to pre-fund the Utility's tax liability that will be due as the Utility collects the dedicated rate component, or DRC, used to secure repayment of the first series of ERBs from its customers. Until these taxes are fully paid, the Utility provides customers a "carrying cost" credit to compensate customers for the use of proceeds from the second series of ERBs. The equity component of this carrying cost credit of approximately $56 million resulted in a net income decrease in 2006 and is expected to impact net income by approximately $48 million in 2007. The carrying cost credit will decline each year over the term of the ERBs until the ERBs are fully repaid in 2012. Additionally, the Utility recovered net interest costs related to disputed generator claims for the period between the effective date of the plan of reorganization and the first series of ERBs, and for certain energy supplier refund litigation costs, resulting in an increase of approximately $39 million to net income in 2006.

In addition to the key factors discussed above, PG&E Corporation's and the Utility's future results of operation and financial condition are subject to the risk factors discussed in detail in the section entitled "Risk Factors" below.

FORWARD-LOOKING STATEMENTS

This combined annual report and the letter to shareholders that accompanies it contains forward-looking statements that are necessarily subject to various risks and uncertainties. These statements are based on current estimates, expectations and projections about future events, and assumptions regarding these events and management's knowledge of facts as of the date of this report. These forward-looking statements relate to, among other matters, estimated capital expenditures, estimated Utility rate base, estimated environmental remediation liabilities, the anticipated outcome of various regulatory and legal proceedings, future cash flows, and the level of future equity or debt issuances, and are also identified by words such as "assume," "expect," "intend," "plan," "project," "believe," "estimate," "predict," "anticipate," "aim," "may," "might," "should," "would," "could," "goal," "potential" and similar expressions. PG&E Corporation and the Utility are not able to predict all the factors that may affect future results. Some of the factors that could cause future results to differ materially from those expressed or implied by the forward-looking statements, or from historical results, include, but are not limited to:

- the Utility's ability to timely recover costs through rates;
- the outcome of regulatory proceedings, including ratemaking proceedings pending at the CPUC and the FERC;
- the adequacy and price of electricity and natural gas supplies, and the ability of the Utility to manage and respond to the volatility of the electricity and natural gas markets;
- the effect of weather, storms, earthquakes, fires, floods, disease, other natural disasters, explosions, accidents, mechanical breakdowns, acts of terrorism, and other events or hazards on the Utility's facilities and operations, its customers and third parties on which the Utility relies;
- the potential impacts of climate change on the Utility's electricity and natural gas operations;
- changes in customer demand for electricity and natural gas resulting from unanticipated population growth or decline, general economic and financial market conditions, changes in technology, including the development of alternative energy sources, or other reasons;
- operating performance of the Utility's Diablo Canyon nuclear generating facilities, or Diablo Canyon, the occurrence of unplanned outages at Diablo Canyon, or the temporary or permanent cessation of operations at Diablo Canyon;
- the ability of the Utility to recognize benefits from its initiatives to improve its business processes and customer service;
- the ability of the Utility to timely complete its planned capital investment projects;
- the impact of changes in federal or state laws, or their interpretation, on energy policy and the regulation of utilities and their holding companies;
- the impact of changing wholesale electric or gas market rules, including the California Independent System Operator's, or CAISO, new rules to restructure the California wholesale electricity market;
- how the CPUC administers the conditions imposed on PG&E Corporation when it became the Utility's holding company;
- the extent to which PG&E Corporation or the Utility incurs costs in connection with pending litigation that are not recoverable through rates, from third parties, or through insurance recoveries;
- the ability of PG&E Corporation and/or the Utility to access capital markets and other sources of credit;
- the impact of environmental laws and regulations and the costs of compliance and remediation; and
- the effect of municipalization, direct access, community choice aggregation, or other forms of bypass.

For more information about the more significant risks that could affect the outcome of these forward-looking statements and PG&E Corporation's and the Utility's future financial condition and results of operations, see the discussion under the heading "Risk Factors" below. PG&E Corporation and the Utility do not undertake an obligation to update forward-looking statements, whether in response to new information, future events or otherwise.

RESULTS OF OPERATIONS

The table below details certain items from the accompanying Consolidated Statements of Income for 2006, 2005 and 2004.

(in millions)	Year ended December 31, 2006	2005	2004
Utility			
Electric operating revenues	$ 8,752	$ 7,927	$ 7,867
Natural gas operating revenues	3,787	3,777	3,213
Total operating revenues	12,539	11,704	11,080
Cost of electricity	2,922	2,410	2,770
Cost of natural gas	2,097	2,191	1,724
Operating and maintenance	3,697	3,399	2,848
Recognition of regulatory assets	–	–	(4,900)
Depreciation, amortization and decommissioning	1,708	1,734	1,494
Total operating expenses	10,424	9,734	3,936
Operating income	2,115	1,970	7,144
Interest income	175	76	50
Interest expense	(710)	(554)	(667)
Other expense, net[1]	(7)	–	(5)
Income before income taxes	1,573	1,492	6,522
Income tax provision	602	574	2,561
Income available for common stock	$ 971	$ 918	$ 3,961
PG&E Corporation, Eliminations and Other[2]			
Operating revenues	$ –	$ (1)	$ –
Operating (gain) expenses	7	(1)	26
Operating loss	(7)	–	(26)
Interest income	13	4	13
Interest expense	(28)	(29)	(130)
Other expense, net[1]	(6)	(19)	(93)
Loss before income taxes	(28)	(44)	(236)
Income tax benefit	(48)	(30)	(95)
Income (loss) from continuing operations	20	(14)	(141)
Discontinued operations[3]	–	13	684
Net income (loss)	$ 20	$ (1)	$ 543
Consolidated Total			
Operating revenues	$12,539	$11,703	$11,080
Operating expenses	10,431	9,733	3,962
Operating income	2,108	1,970	7,118
Interest income	188	80	63
Interest expense	(738)	(583)	(797)
Other expenses, net[1]	(13)	(19)	(98)
Income before income taxes	1,545	1,448	6,286
Income tax provision	554	544	2,466
Income from continuing operations	991	904	3,820
Discontinued operations[3]	–	13	684
Net income	$ 991	$ 917	$ 4,504

(1) Includes preferred stock dividend requirement as other expense.
(2) PG&E Corporation eliminates all intercompany transactions in consolidation.
(3) Discontinued operations reflect items related to its former subsidiary, NEGT. See Note 7 of the Notes to the Consolidated Financial Statements for further discussion.

UTILITY

The Utility's rates for electricity and natural gas utility services are determined based on its costs of service. The CPUC and the FERC determine the amount of "revenue requirements" that the Utility can collect to recover the Utility's operating and capital costs and earn a fair return. Revenue requirements are primarily determined based on the Utility's forecast of future costs, including the costs of purchasing electricity and natural gas for the Utility's customers. The CPUC also has established ratemaking mechanisms to permit the Utility to timely recover its costs to procure electricity and natural gas for its customers in the energy markets.

The Utility's revenues for natural gas transmission services are subject to fluctuation because most of the Utility's intrastate natural gas transmission capacity has not been sold under long-term contracts that provide for recovery of all fixed costs through the collection of fixed reservation charges. Instead, the Utility sells most of its capacity based on the volume of gas the Utility's customers actually ship, which exposes the Utility to volumetric risk. (See further discussion in the Natural Gas Transportation and Storage section in "Risk Management Activities" below.) In addition, the Utility faces some volumetric risk in collecting its full authorized electric transmission revenue requirement authorized in its Transmission Owner rate case, or TO rate case (see further discussion below).

The GRC is the primary proceeding in which the CPUC determines the amount of revenue requirements the Utility can recover for basic business and operational costs related to its electricity and natural gas distribution and electricity generation operations. The CPUC generally conducts a GRC every three years. The CPUC sets revenue requirements for a three-year period based on a forecast of costs for the first, or test, year. The CPUC may authorize the Utility to receive annual increases (known as attrition adjustments) for the years between GRCs in order to avoid a reduction in earnings in those years due to, among other things, inflation and increases in invested capital. (See the discussion of the proposed settlement of the Utility's 2007 GRC below under "Regulatory Matters – 2007 General Rate Case." The settlement proposes that the Utility's next GRC would occur in 2011 instead of 2010.) In addition, the CPUC generally conducts an annual cost of capital proceeding to determine the Utility's authorized capital structure and the authorized rate of return that the Utility may earn on its electricity and natural gas distribution and electricity generation assets. The cost of capital proceeding establishes relative weightings of common equity, preferred equity, and debt in the Utility's total authorized capital structure for a specific year. The CPUC then establishes the authorized return on each component that the Utility will collect in its authorized rates. The CPUC waived the requirement for the Utility to file a 2007 cost of capital application and allowed the Utility to maintain the 2006 authorized cost of capital and capital structure, including the Utility's authorized equity component of 52% and the authorized ROE of 11.35%.

The FERC sets the Utility's rates for electric transmission services. The primary FERC ratemaking proceeding to determine the amount of revenue requirements the Utility can recover for its electric transmission costs and ROE is the TO rate case. A TO rate case is generally held every year and sets rates for a one-year period. The Utility is typically able to charge new rates, subject to refund, before the outcome of the FERC ratemaking review process. (See discussion of the pending TO rate case below under "Regulatory Matters – FERC Transmission Owner Rate Case.")

The Utility's rates reflect the sum of individual revenue requirement components authorized by the CPUC and the FERC. Changes in any individual revenue requirement affect customers' rates and could affect the Utility's revenues. Pending regulatory proceedings that could result in rate changes and affect the Utility's revenues are discussed below under "Regulatory Matters." In annual true-up proceedings, the Utility requests the CPUC to authorize an adjustment to electric and gas rates to (1) reflect over- and under-collections in the Utility's major electric and gas balancing accounts, and (2) implement various other electricity and gas revenue requirement changes authorized by the CPUC and the FERC. Generally, rate changes become effective on the first day of the following year. Balances in all CPUC-authorized accounts are subject to review, verification audit and adjustment, if necessary, by the CPUC.

The timing of the CPUC and FERC decisions affect when the Utility is able to record authorized revenues. To minimize rate fluctuations between January 1, 2007 and the dates that rate changes from the 2007 GRC and the most recent TO rate case become effective, the CPUC authorized the Utility to continue collecting the same amount of electric revenues after January 1, 2007 as before January 1, 2007. Differences between the amount of revenues collected after January 1, 2007 and the amount authorized in the 2007 GRC will be tracked in regulatory accounts. When the decision is issued, the Utility would record revenues equal to the amount of the difference between authorized revenues and collected revenues that had accumulated since January 1, 2007. Any revenue requirement changes resulting from the pending TO rate case will be deemed to have been effective as of March 1, 2007. In both cases, the Utility would refund any over-collected amounts, with interest, to customers.

The following presents the Utility's operating results for 2006, 2005 and 2004.

Electric Operating Revenues

In addition to electricity provided by the Utility's own generation facilities and by third parties under power purchase agreements, the Utility relies on electricity provided under long-term electricity contracts entered into by the California Department of Water Resources, or the DWR, to meet a material portion of the Utility's customers' demand or "load." Revenues collected on behalf of the DWR and the DWR's related costs are not included in the Utility's Consolidated Statements of Income, reflecting the Utility's role as a billing and collection agent for the DWR's sales to the Utility's customers. Changes in the DWR's revenue requirements do not affect the Utility's revenues.

The following table provides a summary of the Utility's electric operating revenues:

(in millions)	2006	2005	2004
Electric revenues	**$10,871**	$ 9,626	$ 9,800
DWR pass-through revenue	**(2,119)**	(1,699)	(1,933)
Total electric operating revenues	**$ 8,752**	$ 7,927	$ 7,867
Total electricity sales (in GWh)	**64,725**	61,150	62,998

The Utility's electric operating revenues increased in 2006 by approximately $825 million, or approximately 10%, compared to 2005 mainly due to the following factors:

- Electricity procurement costs, which are passed through to customers, increased by approximately $490 million. (See "Cost of Electricity" below.)
- The DRC charge related to the ERBs increased by approximately $175 million (see further discussion in Notes 3 and 6 of the Notes to the Consolidated Financial Statements). During 2005, the Utility collected only the DRC for the first series of ERBs that were issued on February 10, 2005. During 2006, the Utility collected the DRC associated with the first series of ERBs and the DRC related to the second series of ERBs, issued on November 9, 2005.
- The Utility recovered approximately $136 million of costs it incurred as a SC, from April 1998 through September 2006, based on a FERC order issued in August of 2006. SC costs incurred after September 2006 and in the future are considered probable of recovery.
- The Utility recognized attrition adjustments to the Utility's authorized 2003 base revenue requirements of approximately $135 million as authorized in the 2003 GRC.
- The Utility recorded approximately $112 million in revenue requirements to recover a pension contribution attributable to the Utility's electric distribution and generation operations. (See "Regulatory Matters – Defined Benefit Pension Plan Contribution" below.)
- Transmission revenues increased by approximately $90 million primarily due to an increase in revenues as authorized in the Utility's last FERC TO rate case.
- The Utility recognized approximately $65 million due to the recovery of net interest costs related to disputed generator claims for the period between April 12, 2004, the effective date of the Utility's plan of reorganization, and February 10, 2005, when the first series of ERBs was issued, and for certain energy supplier refund litigation costs. Recovery of these costs in the Energy Recovery Bond Balancing Account, or ERBBA, was authorized by the CPUC upon their completion of the verification audit in the 2005 Annual Electric True-Up Proceeding in September 2006.

- The Utility recovered approximately $59 million of net interest costs related to disputed generator claims incurred after the issuance of the first series of ERBs. Recovery of these costs through the ERBBA was authorized by the CPUC. Costs incurred after December 2006 and in the future are considered probable of recovery. (See "Interest Income" and "Interest Expense" below for further discussion.)

These were partially offset by the following:

- In 2005, the Utility recognized approximately $160 million due to the resolution of the Utility's claims for shareholder incentives related to energy efficiency and other public purpose programs. No similar amount was recorded in 2006.
- In 2005, the Utility recognized approximately $154 million related to revenue requirements associated with the settlement regulatory asset provided under the Chapter 11 Settlement Agreement and the recovery of costs on the deferred tax component of the settlement regulatory asset. No similar amounts were recorded in 2006.
- The carrying cost credit, including both the debt and equity components, associated with the issuance of the second series of ERBs, decreased electric operating revenues by approximately $123 million in 2006 from 2005. The second series of ERBs was issued to pre-fund the Utility's tax liability that will be due as the Utility collects the DRC related to the first series from its customers over the term of the ERBs. Until these taxes are fully paid, the Utility provides customers a carrying cost credit, computed at the Utility's authorized rate of return on rate base to compensate them for the use of proceeds from the second series of ERBs.

The Utility's electric operating revenues increased in 2005 by approximately $60 million, or approximately 1%, compared to 2004 mainly due to the following factors:

- The Utility began collecting the DRC charge related to ERBs in 2005, which together with revenue requirements associated with the ERBBA, increased electric operating revenues by approximately $390 million in 2005 compared to 2004. (See further discussion in Notes 3 and 6 of the Notes to the Consolidated Financial Statements.)
- The Utility recognized approximately $160 million in 2005 due to the resolution of the Utility's claims for shareholder incentives related to energy efficiency and other public purpose programs covering 1994–2001. No similar amount was recorded in 2004.
- Miscellaneous other electric operating revenues, including revenues associated with public purpose programs and advanced metering and demand response programs, increased by approximately $140 million.
- The Utility recognized approximately $100 million of revenues in 2005 relating to the Self-Generation Incentive Program. No similar amount was recorded in 2004.
- The Utility recognized attrition adjustments to the Utility's authorized 2003 base revenue requirements, which together with an increase in revenues authorized in the 2004 cost of capital decision, increased electric operating revenues by approximately $90 million, compared to 2004.
- The Utility recognized approximately $80 million in 2005 due to recovery of certain costs incurred in connection with electric industry restructuring. No similar amount was recorded in 2004.
- Electric operating revenues included approximately $70 million in refunds in revenue requirements to customers in 2004, with no similar amount in 2005.

These were partially offset by the following:

- Electricity procurement and transmission costs, which are passed through to customers, decreased by approximately $530 million compared to 2004.
- After the issuance of the first series of ERBs on February 10, 2005, the Utility was no longer able to collect the revenue requirement associated with the settlement regulatory asset, decreasing electric operating revenues by approximately $435 million compared to 2004. (See further discussion in Notes 3 and 6 of the Notes to the Consolidated Financial Statements.)

The Utility expects that its electric operating revenues for the period 2007 through 2010 will increase to the extent authorized by the CPUC in the 2007 GRC. (For further discussion, see "Regulatory Matters" under "2007 General Rate Case" below.) *In addition, the Utility expects to continue* to collect revenue requirements related to CPUC-approved capital expenditure projects, including the new Utility-owned generation projects and advanced metering infrastructure. (See "Capital Expenditures" below.) The Utility also expects electric transmission revenues will increase on March 1, 2007 subject to the FERC's authorization. (See "Regulatory Matters – FERC Transmission Rate Case" below.)

Cost of Electricity

The Utility's cost of electricity includes electricity purchase costs, hedging costs and the cost of fuel used by its own generation facilities or supplied to other facilities under tolling agreements, but it excludes costs to operate its own generation facilities, which are included in operating and maintenance expense. Electricity purchase costs and the cost of fuel used in Utility-owned generation are passed through to customers in rates. (See "Electric Operating Revenues" above for further details.)

The Utility is required to dispatch, or schedule, all of the electricity resources within its portfolio, including electricity provided under the DWR contracts, in the most cost-effective way. This requirement, in certain cases, requires the Utility to schedule more electricity than is necessary to meet its load and to sell this additional electricity on the open market. The Utility typically schedules excess electricity when the expected sales proceeds exceed the variable costs to operate a generation facility or buy electricity under an optional contract. Proceeds from the sale of surplus electricity are allocated between the Utility and the DWR based on the percentage of volume supplied by each entity to the Utility's total load. The Utility's net proceeds from the sale of surplus electricity after deducting the portion allocated to the DWR are recorded as a reduction to the cost of electricity.

The following table provides a summary of the Utility's cost of electricity and the total amount and average cost of purchased power, excluding both the cost and volume of electricity provided by the DWR to the Utility's customers:

(in millions)	2006	2005	2004
Cost of purchased power	**$ 3,114**	$ 2,706	$ 2,816
Proceeds from surplus sales allocated to the Utility	**(343)**	(478)	(192)
Fuel used in own generation	**151**	182	146
Total cost of electricity	**$ 2,922**	$ 2,410	$ 2,770
Average cost of purchased power per GWh	**$ 0.084**	$ 0.079	$ 0.082
Total purchased power (GWh)	**36,913**	34,203	34,525

In 2006, the Utility's cost of electricity increased by approximately $512 million, or 21%, compared to 2005, mainly due to the following factors:

- The increase in total purchased power of 2,710 Gigawatt hours, or GWh, and the increase in the average cost of purchased power of $0.005 per GWh in 2006, compared to 2005, resulted in an increase of approximately $408 million in the cost of purchased power. This was primarily caused by an increase in volume of purchased power due to greater customer demand during the July 2006 "heat storm" (see discussion below under "Regulatory Matters — Catastrophic Events Memorandum Account") and a decrease in the volume of electricity provided by the DWR to the Utility's customers. Additionally, the Utility's service to customers who purchase "bundled" services (e.g., generation, transmission and distribution) grew, further increasing volume.

In 2005, the Utility's cost of electricity decreased by approximately $360 million, or 13%, compared to 2004, mainly due to the following factors:

- Increased electricity production from the Utility's hydroelectric generation facilities due to above average rainfall during 2005 increased the proceeds from surplus sales allocated to the Utility by $286 million.
- The volume of total purchased power decreased by 322 GWh in 2005 primarily because increased electricity from the Utility's hydroelectric facilities and Diablo Canyon reduced the amount of electricity the Utility needed to purchase. During 2005, Diablo Canyon's refueling outage lasted only 41 days compared to 2004 when the outage lasted 129.5 days. Also, the average cost of purchased power decreased by $0.003 per GWh in 2005 from 2004.

The Utility's cost of electricity in 2007 will depend upon electricity prices, the duration of the Diablo Canyon refueling outage, and changes in customer demand which will directly impact the amount of power the Utility will be required to purchase. (See the "Risk Management Activities" section of this MD&A.)

The Utility's future cost of electricity also may be affected by potential federal or state legislation or rules which may regulate the emissions of greenhouse gases from the Utility's electric generating facilities or the generating facilities from which the Utility procures power. As directed by recent California legislation, the CPUC has adopted an interim greenhouse gas emissions performance standard that would apply to electricity procured or generated by the Utility. Additionally, California recently enacted a greenhouse gas emissions law, Assembly Bill 32, which establishes a regulatory program and schedule for establishing a cap on greenhouse gas emissions in the state at 1990 levels effective by 2020, including a cap on the Utility's emissions of greenhouse gases. The Utility's existing and forecasted emissions of greenhouse gases are relatively low compared to average emissions by other electric utilities and generators in the country, and the Utility's incremental costs of complying with greenhouse gas emissions regulations being promulgated by the CPUC and other California agencies are expected to be fully recovered in rates from the Utility's customers under the CPUC's ratemaking standards applicable to electricity procurement costs.

Natural Gas Operating Revenues

The Utility sells natural gas and natural gas transportation services to its customers. The Utility's transportation system transports gas throughout California to the Utility's distribution system, which in turn, delivers natural gas to end-use customers. The Utility also delivers natural gas to off-system markets, primarily in Southern California, in competition with interstate pipelines.

The Utility's natural gas customers consist of two categories: core and non-core customers. The core customer class is comprised mainly of residential and smaller commercial natural gas customers. The non-core customer class is comprised of industrial and larger commercial natural gas customers. The Utility provides natural gas delivery services to all core and non-core customers connected to the Utility's system in its service territory. Core customers can purchase natural gas from alternate energy service providers or elect to have the Utility provide both delivery service and natural gas supply. The Utility does not provide procurement service to non-core customers. If non-core customers would like the Utility to provide them with procurement service they must elect to have core service provided. When the Utility provides both supply and delivery, the Utility refers to the service as natural gas bundled service. In 2006, core customers represented over 99% of the Utility's total customers and approximately 40% of its total natural gas deliveries, while non-core customers comprised less than 1% of the Utility's total customers and approximately 60% of its total natural gas deliveries. Because the Utility sells most of its capacity based on the volume of natural gas the Utility's customers actually ship, the Utility is exposed to volumetric risk.

The Utility recovers the cost of gas (subject to the ratemaking mechanism discussed below), acquired on behalf of core procurement customers, through its retail gas rates. The Utility is protected against after-the-fact reasonableness reviews of these gas procurement costs under an incentive mechanism known as the Core Procurement Incentive Mechanism, or CPIM. Under the CPIM, the Utility's purchase costs for a twelve-month period are compared to an aggregate market-based benchmark based on a weighted average of published monthly and daily natural gas price indices at the points where the Utility typically purchases natural gas. The CPIM establishes a "tolerance band" around the benchmark index price, and all costs within the tolerance band are fully recovered from core customers. If total natural gas costs fall below the tolerance band, the Utility's customers and shareholders will share 75% and 25% of the savings below the tolerance band, respectively. Conversely, if total natural gas costs rise above the tolerance band, the Utility's core customers and shareholders share equally the costs above the tolerance band. The shareholder award is capped at the lower of 1.5% of total natural gas commodity costs or $25 million. While this incentive mechanism remains in place, changes in the price of natural gas, consistent with the market-based benchmark, are not expected to materially impact net income. (See the "Risk Management Activities" section of this MD&A.)

The CPIM is focused on short-term procurement of natural gas. As natural gas prices have become more volatile, the Utility has sought CPUC authority to secure long-term supplies of natural gas and hedge the price risk associated with these contracts outside of the CPIM. (See the "Risk Management Activities" section of this MD&A.) The Utility is at risk to the extent that the CPUC may disallow portions of the hedging costs based on its subsequent review of the Utility's compliance with the filed plan.

The following table provides a summary of the Utility's natural gas operating revenues:

(in millions)	2006	2005	2004
Bundled natural gas revenues	**$3,472**	$3,539	$2,943
Transportation service-only revenues	**315**	238	270
Total natural gas operating revenues	**$3,787**	$3,777	$3,213
Average bundled revenue per Mcf of natural gas sold	**$12.89**	$13.05	$10.51
Total bundled natural gas sales (in millions of Mcf)	**269**	271	280

In 2006, the Utility's natural gas operating revenues increased by approximately $10 million, or less than 1%, compared to 2005. The increase in natural gas operating revenues was primarily due to the following factors:

- The Utility recorded approximately $43 million in revenue requirements for a pension contribution attributable to the Utility's natural gas distribution operations. (See "Regulatory Matters — Defined Benefit Pension Plan Contribution" below.)
- Attrition adjustments to the Utility's 2003 GRC authorized revenue requirements, and revenues authorized in the 2006 cost of capital proceeding contributed approximately $22 million.
- Miscellaneous natural gas revenues increased by approximately $26 million.
- Transportation service-only revenues increased by approximately $77 million, or 32%, primarily as a result of an increase in rates.

These were partially offset by the following:

- The cost of natural gas, which is passed-through to customers, decreased by approximately $132 million, as further discussed below under "Cost of Natural Gas."
- In 2005, the Utility recognized approximately $26 million due to the resolution of the Utility's claims for shareholder incentives related to energy efficiency and other public purpose programs. No similar amount was recorded in 2006.

In 2005, the Utility's natural gas operating revenues increased by approximately $564 million, or 18%, compared to 2004. The increase in natural gas operating revenues was mainly due to the following factors:

- Excluding the impact of the 2003 GRC decision, the 2005 cost of capital proceeding, and the Utility's recovery of shareholder incentives relating to energy efficiency and other public purpose programs, bundled natural gas operating revenues increased by approximately $580 million, or 20%. The increase was attributable to an increase in the cost of natural gas, which is passed through to customers, and partially offset by a decrease in the volume of gas purchased.
- Attrition adjustments to the Utility's 2003 GRC authorized revenue requirements, and revenues authorized in the 2005 cost of capital proceeding contributed approximately $42 million in 2005 compared to 2004.
- The Utility recognized approximately $26 million in 2005 due to the resolution of the Utility's claims for shareholder incentives related to energy efficiency and other public purpose programs covering 1994–2001. No similar amount was recorded in 2004.

These were partially offset by the following:

- The approval of the 2003 GRC in May 2004 resulted in the Utility recording approximately $52 million in revenues related to 2003 in 2004. No comparable amount was recorded in 2005.
- Transportation service-only revenues decreased by approximately $32 million, or 12%, primarily as a result of a decrease in rates.

The Utility expects that its natural gas operating revenues for 2007 will increase due to an annual rate escalation as authorized in the Gas Accord III Settlement. In addition, the Utility expects that its natural gas operating revenues for the period 2007 through 2010 will increase to the extent authorized by the CPUC in the 2007 GRC and as may be authorized by the CPUC in the new Gas Transmission and Storage Rate Case that will set new rates effective January 1, 2008. (See "Regulatory Matters — Gas Transmission and Storage Rate Case" below.) Finally, future natural gas operating revenues will be impacted by changes in the cost of natural gas.

Cost of Natural Gas

The Utility's cost of natural gas includes the purchase costs of natural gas and transportation costs on interstate pipelines, but excludes the costs associated with operating and maintaining the Utility's intrastate pipeline, which are included in operating and maintenance expense.

The following table provides a summary of the Utility's cost of natural gas:

(in millions)	2006	2005	2004
Cost of natural gas sold	$1,958	$2,051	$1,591
Cost of natural gas transportation	139	140	133
Total cost of natural gas	$2,097	$2,191	$1,724
Average cost per Mcf of natural gas sold	$ 7.28	$ 7.57	$ 5.68
Total natural gas sold (in millions of Mcf)	269	271	280

In 2006, the Utility's total cost of natural gas decreased by approximately $94 million, or 4%, compared to 2005, primarily due to a decrease in the average market price of natural gas purchased of approximately $0.29 per thousand cubic feet, or Mcf, or 4%.

In 2005, the Utility's total cost of natural gas, increased by approximately $467 million, or 27%, compared to 2004, primarily due to an increase in the average market price of natural gas purchased of approximately $1.89 per Mcf, or 33%, partially offset by a decrease in volume of 9 Mcf, or 3%.

The Utility's cost of natural gas in 2007 will be primarily affected by the prevailing costs of natural gas, which are determined by North American regions that supply the Utility. As discussed above under "Natural Gas Operating Revenues," the CPUC has authorized the Utility to execute hedges on behalf of its core gas customers. The Utility also has requested the CPUC to approve a settlement agreement that provides for a long-term hedge program. (For further discussion, see "Risk Management Activities" below.) The total cost of gas will also be affected by customer demand.

Operating and Maintenance

Operating and maintenance expenses consist mainly of the Utility's costs to operate and maintain its electricity and natural gas facilities, customer accounts and service expenses, public purpose program expenses, and administrative and general expenses. Generally, these expenses are offset by corresponding annual revenues authorized by the CPUC and the FERC in various rate proceedings.

During 2006, the Utility's operating and maintenance expenses increased by approximately $298 million, or 9%, compared to 2005, mainly due to the following factors:

- Pension contributions as a result of the CPUC-approved settlement (see "Regulatory Matters — Defined Benefit Pension Plan Contribution" below) resulted in an additional $176 million in pension expense.
- Administration expenses for low-income customer assistance programs, the Self-Generation Incentive Program, advanced metering infrastructure and other energy incentives increased by approximately $125 million.
- Compensation expense increased approximately $54 million, reflecting increased base salaries and incentives.
- Expenses for outside consulting, contracts and various programs and initiatives, including strategies to achieve operational excellence and improved customer service, increased by approximately $50 million.
- Expenses related to the accrual of severance costs as part of the Utility's strategies to achieve operational excellence and improved customer service increased by approximately $35 million.
- Franchise fee expense and property taxes increased by approximately $21 million. The increase in franchise fee expense was due to higher revenues and franchise fee rates. The increase in property taxes was due to electric plant growth, a tax rate increase and increases in assessed values in 2006.

The above increases (totaling $461 million) were partially offset by a decrease of $154 million related to an additional reserve made in 2005 to settle the majority of claims related to alleged exposure to chromium at the Utility's natural gas compressor stations. No similar adjustment was recorded in 2006. Of the $461 million of increased expenses, approximately $366 million is recoverable in rates and did not affect net income in 2006. The additional reserve of $154 million is not recoverable in rates.

During 2005, the Utility's operating and maintenance expenses increased by approximately $551 million, or 19%, compared to 2004, mainly due to the following factors:

- An additional $154 million was reserved to settle the majority of claims related to alleged exposure to chromium at the Utility's natural gas compressor stations. (See "Legal Matters" in Note 17 of the Notes to the Consolidated Financial Statements for further discussion.)
- Administration expenses for low-income customer assistance programs and community outreach programs increased by approximately $110 million.
- Approximately $100 million in Self-Generation Incentive Program expenses that were deferred in prior periods because no specific revenue recovery mechanism was in place were recognized in 2005. (See related revenues in "Electric Operating Revenues.")
- Expenses for outside consulting, contract and legal expense and various programs and initiatives, including strategies to achieve operational excellence and improved customer service, increased by approximately $55 million.
- Natural gas transportation operations charges increased by approximately $60 million mainly due to rate increases for pipeline demand and transportation.
- The estimated cost of environmental remediation related to the Topock and Hinkley gas compressor stations increased expenses by approximately $40 million. (See "Environmental Matters" in Note 17 of the Notes to the Consolidated Financial Statements for further discussion.)
- Property taxes increased approximately $25 million mainly due to higher assessments in 2005.

These increases were partially offset by a decrease of approximately $50 million in operating and maintenance expenses at Diablo Canyon in 2005 compared to 2004 when there was a longer refueling outage.

Approximately $306 million of the above increases were recoverable in rates and did not affect net income for 2005.

Operating and maintenance expenses are influenced by wage inflation, benefits, property taxes, the timing and length of Diablo Canyon refueling outages, environmental remediation costs, legal costs and various other administrative and general expenses. The Utility's operating and maintenance expenses in 2007 are expected to increase as a result of increased expenses related to various programs and initiatives, including public purpose programs and strategies to achieve operational excellence and improved customer service. (See "Overview" section in this MD&A for further discussion.) In connection with the Utility's continued effort to streamline processes to achieve cost and operating efficiencies, jobs from numerous locations around California are being consolidated and a number of positions have been eliminated. Impacted employees may elect severance or reassignment. As discussed above, the Utility has already incurred approximately $35 million in severance costs relating to the positions that have already been eliminated. The Utility expects that more positions will be eliminated and estimates that it may incur up to approximately $33 million for future severance expenses that would be included in future operating and maintenance expenses. (See further discussion in Note 17 of the Notes to the Consolidated Financial Statements.)

Recognition of Regulatory Assets

The Utility recorded the regulatory assets provided for under the Chapter 11 Settlement Agreement in the first quarter of 2004. This resulted in a one-time non-cash, pre-tax gain of $3.7 billion for the settlement regulatory asset and $1.2 billion for the Utility retained generation regulatory assets, for a total after-tax gain of $2.9 billion.

Depreciation, Amortization and Decommissioning

In 2006, the Utility's depreciation, amortization and decommissioning expenses decreased by approximately $26 million, or 1%, compared to 2005, mainly due to the following factors:

- The Utility recorded approximately $141 million in 2005 for amortization of the settlement regulatory asset. Because the settlement regulatory asset was refinanced with the issuance of the first series of ERBs on February 10, 2005, the Utility had no similar amount in 2006.
- In 2005, the Utility recorded depreciation expense of approximately $30 million related to recovery of capital plant costs associated with electric industry restructuring costs that a December 2004 settlement agreement allowed the Utility to collect through rates in 2005. There was no similar depreciation expense in 2006.

- Amortization of the regulatory asset related to rate recovery bonds, or RRBs, decreased by approximately $19 million in 2006, compared to 2005, due to the declining balance of the RRBs.

These were partially offset by the following:

- An increase of approximately $137 million related to the amortization of the ERB regulatory asset. During 2005, the Utility amortized only the ERB regulatory asset for the first series of ERBs that were issued on February 10, 2005. During 2006, the Utility amortized the ERB regulatory asset for the second series of ERBs that were issued on November 9, 2005 in addition to the first series.
- Depreciation expense increased by approximately $35 million as a result of plant additions in 2006.

In 2005, the Utility's depreciation, amortization and decommissioning expenses increased by approximately $240 million, or 16%, compared to 2004, mainly due to the following factors:

- The Utility recorded additional amortization expense of approximately $202 million in 2005 as it began to amortize the ERB regulatory asset.
- In 2004, following the 2003 GRC decision in May 2004 that authorized lower depreciation rates, the Utility recorded an approximately $38 million decrease to depreciation expense. There was no similar reduction in 2005.
- The Utility recorded depreciation expense of approximately $30 million related to recovery of capital plant costs associated with electric industry restructuring costs the December 2004 settlement agreement allowed the Utility to collect through rates. There was no similar depreciation expense in 2004.

These were partially offset by the following:

- Amortization of the regulatory asset related to the RRBs decreased by approximately $20 million in 2005 compared to 2004 again reflecting the declining balance of the RRBs.
- Amortization of the settlement regulatory asset decreased by approximately $10 million in 2005 reflecting the refinancing of the settlement regulatory asset with the ERBs.

The Utility's depreciation, amortization and decommissioning expenses in 2007 are expected to increase as a result of an overall increase in capital expenditures.

Interest Income

In 2006, the Utility's interest income increased by approximately $99 million, or 130%, compared to 2005, primarily due to an increase in interest earned on escrow related to disputed generator claims which are passed through to customers (see "Electric Operating Revenues" above for further discussion), a FERC decision approving recovery of SC costs, including interest, and an increase in interest rates associated with certain regulatory balancing accounts. These increases were partially offset by a decrease in interest earned on short-term investments as a result of lower short-term investment balances.

In 2005, the Utility's interest income increased by approximately $26 million, or 52%, compared to 2004, primarily due to a higher balance and rate of return on short-term investments in 2005 compared to 2004.

The Utility's interest income in 2007 will be primarily affected by interest rate levels.

Interest Expense

In 2006, the Utility's interest expense increased by approximately $156 million, or 28%, compared to 2005, primarily due to an increase in interest expense related to disputed generator claims which are recovered as an offset to interest income (net interest costs) through the ERBBA (see "Electric Operating Revenues" above for further discussion), interest expense associated with the ERBs and accrued interest on higher balances in certain regulatory balancing accounts combined with an increase in the interest rates associated with these accounts. These increases were partially offset by lower interest expense on the RRBs due to their declining balance.

In 2005, the Utility's interest expense decreased by approximately $113 million, or 17%, compared to 2004, primarily due to a decrease in net interest costs on disputed generator claims and energy crisis interest expense incurred in 2004 prior to the Utility's emergence from Chapter 11. In addition, the net additional interest expense of approximately $76 million resulting from the ERB refinancing was offset by a decrease in interest expense of approximately $18 million related to the RRBs and a decrease in interest expense of approximately $56 million incurred on a lower amount of outstanding short-term debt.

The Utility's interest expense in 2007 and subsequent periods will be impacted by changes in interest rates as the Utility's short-term debt and a portion of its long-term debt are interest rate-sensitive. In addition, future interest expense is expected to increase due to higher expected financing resulting from an overall increase in infrastructure investments.

Income Tax Expense

In 2006, the Utility's income tax expense increased by approximately $28 million, or 5%, compared to 2005, primarily due to the increase in pre-tax income of $79 million for 2006. The effective tax rate remained 38% for both 2006 and 2005.

In 2005, the Utility's tax expense decreased by approximately $2 billion, or 78%, compared to 2004, mainly due to a decrease in pre-tax income of approximately $5 billion in 2005. This decrease is primarily the result of the recognition of regulatory assets associated with the Chapter 11 Settlement Agreement in 2004 with no similar amount recognized in 2005. The effective tax rate for 2005 decreased from 2004 by 1.3 percentage points, to 38%. This decrease was mainly due to increased investment tax credits in 2005.

PG&E CORPORATION, ELIMINATIONS AND OTHERS

Operating Revenues and Expenses

PG&E Corporation's revenues consist mainly of billings to its affiliates for services rendered, all of which are eliminated in consolidation. PG&E Corporation's operating expenses consist mainly of employee compensation and payments to third parties for goods and services. Generally, PG&E Corporation's operating expenses are allocated to affiliates. These allocations are made without mark-up and are eliminated in consolidation.

There were no material changes to PG&E Corporation's operating income in 2006 compared to 2005.

PG&E Corporation's operating expenses in 2005 decreased by $27 million, or 104%, compared to 2004, primarily due to an increase in expenses allocated to affiliates.

Interest Expense

There were no material changes to PG&E Corporation's interest expense in 2006 compared to 2005. PG&E Corporation's interest expense is not allocated to its affiliates.

PG&E Corporation's interest expense in 2005 decreased $101 million, or 78%, compared to 2004, primarily due to the redemption of PG&E Corporation's 6⅞% Senior Secured Notes due 2008, on November 15, 2004.

Other Expense

There were no material changes to PG&E Corporation's other expense in 2006 compared to 2005.

PG&E Corporation's other expense in 2005 decreased $74 million, or 80%, compared to 2004, primarily due to a decrease in the pre-tax charge to earnings related to the change in market value of non-cumulative dividend participation rights included within PG&E Corporation's $280 million of 9.50% Convertible Subordinated Notes due 2010, or Convertible Subordinated Notes.

Income Tax Benefit

PG&E Corporation's income tax benefit in 2006 increased approximately $18 million, or 60%, compared to 2005 primarily due to tax benefits related to capital losses carried forward and used in the PG&E Corporation's 2005 federal and state income tax returns.

PG&E Corporation has $229 million of remaining capital loss carry forwards, which if not used by December 2009, will expire. These capital losses resulted from PG&E Corporation's disposition of its ownership interest in NEGT in 2004 (as discussed further below).

Discontinued Operations

In 2005, PG&E Corporation received additional information from NEGT regarding income to be included in PG&E Corporation's 2004 federal income tax return and amounts previously included in their 2003 federal income tax return. As a result, PG&E Corporation's 2004 federal income tax liability was reduced by approximately $19 million and the 2003 federal income tax liability increased by $6 million, respectively. These two adjustments, netting to $13 million, were recognized in income from discontinued operations in 2005.

In 2004, NEGT's plan of reorganization became effective, at which time NEGT emerged from Chapter 11 and PG&E Corporation's equity ownership in NEGT was cancelled. As a result, PG&E Corporation recorded a gain on disposal of NEGT, net of tax, on its Consolidated Statements of Income for approximately $684 million.

For further discussion on discontinued operations relating to NEGT, see Note 7 of the Notes to the Consolidated Financial Statements.

LIQUIDITY AND FINANCIAL RESOURCES

OVERVIEW

The level of PG&E Corporation's and the Utility's current assets and current liabilities is subject to fluctuation as a result of seasonal demand for electricity and natural gas, energy commodity costs, and the timing and effect of regulatory decisions and financings, among other factors.

PG&E Corporation and the Utility manage liquidity and debt levels in order to meet expected operating and financial needs and maintain access to credit for contingencies. PG&E Corporation and the Utility seek to maintain the Utility's 52% authorized common equity ratio.

At December 31, 2006, PG&E Corporation and its subsidiaries had consolidated cash and cash equivalents of approximately $456 million and restricted cash of approximately $1.4 billion. At December 31, 2006, PG&E Corporation on a stand alone basis had cash and cash equivalents of approximately $386 million; the Utility had cash and cash equivalents of approximately $70 million, and restricted cash of approximately $1.4 billion. Restricted cash primarily consists of approximately $1.3 billion, including interest, in cash held in escrow pending the resolution of the remaining disputed Chapter 11 claims as well as deposits made by customers and other third parties under certain agreements. PG&E Corporation and the Utility maintain separate bank accounts. PG&E Corporation and the Utility primarily invest their cash in institutional money market funds.

The Utility seeks to maintain or strengthen its credit ratings to provide liquidity through efficient access to financial and trade credit, and to reduce financing costs. As of February 16, 2007, the credit ratings on various financing instruments from Moody's Investors Service, or Moody's, and Standard & Poor's Ratings Service, or S&P, were as follows:

	Moody's	S&P
Utility		
Corporate credit rating	Baa1	BBB
Senior unsecured debt	Baa1	BBB
Pollution control bonds backed by bond insurance	Aaa	AAA
Pollution control bonds backed by letters of credit	—(1)	AA-/A-1+
Credit facility	Baa1	BBB
Preferred stock	Baa3	BB+
Commercial paper program	P-2	A-2
PG&E Funding, LLC		
Rate reduction bonds	Aaa	AAA
PG&E Energy Recovery Funding, LLC		
Energy recovery bonds	Aaa	AAA
PG&E Corporation		
Credit facility	Baa3	—

(1) Moody's has not assigned a rating to the Utility's pollution control bonds backed by letters of credit.

Moody's and S&P are nationally recognized credit rating organizations. These ratings may be subject to revision or withdrawal at any time by the assigning rating organization and each rating should be evaluated independently of any other rating. A credit rating is not a recommendation to buy, sell or hold securities.

As of December 31, 2006, PG&E Corporation and the Utility had credit facilities totaling $200 million and $2 billion, respectively, with remaining borrowing capacity on these credit facilities of $200 million and approximately

$1.1 billion, respectively. As of December 31, 2006, the Utility had $144 million of letters of credit outstanding issued under its working capital facility, $460 million of outstanding borrowings under the commercial paper program; and $300 million outstanding under its accounts receivable facility. The Utility is seeking an increase to its bank credit facilities as its accounts receivable facility will expire on March 5, 2007.

The Utility plans to maintain approximately $800 million of unused borrowing capacity to provide liquidity in the event of contingencies such as increases in energy procurement costs and collateral requirements. The Utility eliminated the use of cash as a component of its minimum liquidity reserve in July 2006 and now relies solely on access to the commercial paper market and back-up committed credit lines.

During 2006, the Utility used cash in excess of amounts needed for operations, debt service, capital expenditures and preferred stock requirements to pay quarterly common stock dividends.

The Utility anticipates that it will issue approximately $1.35 billion of long-term debt in 2007 primarily to fund capital expenditures.

DIVIDENDS

PG&E Corporation and the Utility did not declare or pay a dividend during the Utility's Chapter 11 proceeding. With the Utility's emergence from Chapter 11 on April 12, 2004, the Utility resumed the payment of preferred stock dividends. The Utility reinstated the payment of a regular quarterly common stock dividend to PG&E Corporation in January 2005, upon the achievement of the 52% equity ratio targeted in the Chapter 11 Settlement Agreement.

The dividend policies of PG&E Corporation and the Utility are designed to meet the following three objectives:

- Comparability: Pay a dividend competitive with the securities of comparable companies based on payout ratio (the proportion of earnings paid out as dividends) and, with respect to PG&E Corporation, yield (i.e., dividend divided by share price);
- Flexibility: Allow sufficient cash to pay a dividend and to fund investments while avoiding having to issue new equity unless PG&E Corporation's or the Utility's capital expenditure requirements are growing rapidly and PG&E Corporation or the Utility can issue equity at reasonable cost and terms; and
- Sustainability: Avoid reduction or suspension of the dividend despite fluctuations in financial performance except in extreme and unforeseen circumstances.

The target dividend payout ratio range is 50% to 70% of PG&E Corporation's earnings. Dividends are expected to remain in the lower end of PG&E Corporation's target payout range in order to ensure that equity funding is readily available to support capital investment needs. The Boards of Directors retain authority to change their common stock dividend policy and dividend payout ratio at any time, especially if unexpected events occur that would change the Boards' view as to the prudent level of cash conservation. No dividend is payable unless and until declared by the applicable Board of Directors.

During 2006, the Utility paid cash dividends to holders of its preferred stock totaling $14 million. In addition, the Utility paid cash dividends of $494 million on the Utility's common stock. Approximately $460 million in common stock dividends were paid to PG&E Corporation and the remaining amount was paid to PG&E Holdings, LLC, a wholly owned subsidiary of the Utility that held approximately 7% of the Utility's common stock as of February 20, 2007.

In 2006, PG&E Corporation paid common stock dividends of $0.33 per share per quarter, a total of $489 million, including approximately $33 million of common stock dividends paid to Elm Power Corporation, a wholly owned subsidiary of PG&E Corporation that held approximately 7% of PG&E Corporation's common stock as of February 20, 2007. On December 20, 2006, the Board of Directors declared a dividend of $0.33 per share, totaling approximately $123 million that was payable on January 15, 2007, to shareholders of record on December 29, 2006.

On February 21, 2007, the Board of Directors of the Utility declared a cash dividend on various series of its preferred stock payable on May 15, 2007, to shareholders of record on April 30, 2007.

PG&E Corporation and the Utility record common stock dividends declared to Reinvested Earnings.

UTILITY

Operating Activities

The Utility's cash flows from operating activities primarily consist of receipts from customers less payments of operating expenses, other than expenses such as depreciation that do not require the use of cash.

The Utility's cash flows from operating activities for 2006, 2005 and 2004 were as follows:

(in millions)	2006	2005	2004
Net income	**$ 985**	$ 934	$ 3,982
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, amortization, decommissioning and allowance for equity funds used during construction	**1,755**	1,697	1,494
Gain on sale of assets	**(11)**	–	–
Recognition of regulatory assets	**–**	–	(4,900)
Deferred income taxes and tax credits, net	**(287)**	(636)	2,580
Other deferred charges and noncurrent liabilities	**116**	21	(391)
Change in accounts receivable	**128**	(245)	(85)
Change in accrued taxes/income taxes receivable	**28**	(150)	52
Regulatory balancing accounts, net	**329**	254	(590)
Other uses of cash:			
Payments authorized by the Bankruptcy Court on amounts classified as liabilities subject to compromise	**–**	–	(1,022)
Other changes in operating assets and liabilities	**(466)**	491	718
Net cash provided by operating activities	**$2,577**	$2,366	$ 1,838

In 2006, net cash provided by operating activities increased by approximately $211 million from 2005. In addition to the increase from the increase in net income, the net cash provided by operating activities increased primarily due to the following factors:

- The Utility paid approximately $900 million in net tax payments in 2006 compared to approximately $1.4 billion in 2005.
- Deferred income taxes and tax credits decreased approximately $350 million, primarily due to an increased California franchise tax deduction, lower taxable supplier settlement income received and a deduction related to the payment of previously accrued litigation costs.
- Cash settlements with energy suppliers amounted to approximately $300 million in 2006 compared to only $160 million in 2005.
- Collections on balancing accounts increased by approximately $75 million in 2006, compared to 2005, since actual costs during 2006 were less than the forecasted costs used to set revenue requirements.

These increases were partially offset by the following:

- Approximately $290 million of pension contributions that were made during 2006. (See the "Regulatory Matters – Defined Benefit Pension Plan Contribution" below.)
- Approximately $295 million was paid in April 2006 to settle the majority of claims relating to alleged exposure to chromium at the Utility's natural gas compressor stations.
- The Utility had approximately $185 million in additional costs primarily related to power and gas procurement that were unpaid at the end of 2005, compared to $60 million at the end of 2006, primarily due to higher gas prices during 2005.

In 2005, net cash provided by operating activities increased by approximately $528 million from 2004. This is mainly due to the following factors:

- The Utility received approximately $160 million in cash under settlements with third parties to resolve claims relating to the California 2000–2001 energy crisis with no similar settlements in 2004.
- The Utility had approximately $100 million in expenditures related to gas procurement and administrative and general costs that were unpaid at the end of 2005. In 2004, the Utility did not have similar unpaid expenditures.
- Collections on balancing accounts increased by approximately $800 million in 2005, compared to 2004, due to an increase in revenue requirements intended to recover 2004 undercollections.

The 2005 increase in net cash provided by operating activities also reflects the following:

- In 2004, the Utility paid approximately $1 billion of allowed creditor claims on the effective date of the Utility's Chapter 11 plan of reorganization. Other than the $1.4 billion in tax payments described below, no similar amount was paid in 2005.
- In 2005, the Utility paid approximately $1.4 billion in tax payments compared to approximately $100 million in 2004. This increase in tax payments was primarily due to an increase in the taxable amount of payments the Utility received in 2005 under settlement agreements with energy suppliers to resolve claims relating to the California 2000–2001 energy crisis compared to 2004. In addition, 2005 tax payments increased due to a decrease in deductible tax depreciation compared to 2004.
- The Utility paid approximately $60 million more in 2005 compared to 2004 for gas inventory as a result of increased gas prices.

In October 2006, the CPUC approved the 10/20 Plus Winter Gas Savings Program, a conservation incentive that offers residential and commercial customers up to a 20% rebate for reducing their gas usage during January and February 2007. This initiative is expected to lower the Utility's cash inflows primarily during March through April 2007. However, the Utility expects to recover this cash throughout 2007. The Utility forecasts that this initiative will result in approximately $61 million in rebates to customers.

Investing Activities

The Utility's investing activities consist of construction of new and replacement facilities necessary to deliver safe and reliable electricity and natural gas services to its customers. Cash flows from operating activities have been sufficient to fund the Utility's capital expenditure requirements during 2006, 2005 and 2004. Year-to-year variances in cash used in investing activities depend primarily upon the amount and type of construction activities, which can be influenced by storms and other factors.

The Utility's cash flows from investing activities for 2006, 2005 and 2004 were as follows:

(in millions)	**2006**	2005	2004
Capital expenditures	**$(2,402)**	$(1,803)	$(1,559)
Net proceeds from sale of assets	**17**	39	35
Decrease (increase) in restricted cash	**115**	434	(1,577)
Other investing activities, net	**(156)**	(29)	(178)
Net cash used by investing activities	**$(2,426)**	$(1,359)	$(3,279)

Net cash used by investing activities increased by approximately $1 billion in 2006 compared to 2005, primarily due to an increase of approximately $600 million in capital expenditures. In addition, the Utility released more cash from escrow in 2005 upon settlement of disputed Chapter 11 generator claims than in 2006.

Net cash used by investing activities decreased by approximately $1.9 billion in 2005 compared to 2004 due primarily to a decrease in restricted cash. In 2004, the Utility's restricted cash of $2 billion consisted primarily of funds deposited and held in escrow to pay disputed Chapter 11 proceeding claims when resolved. Settlements during 2005 resulted in the release of these funds from escrow.

The Utility expects to maintain a high rate of infrastructure and information technology investment in its gas and electric system to keep pace with economic growth, to enhance the customer experience, and to mitigate the impacts of aging equipment on system performance. The Utility expects capital expenditures will total approximately $2.8 billion or greater in 2007. The higher level of capital investment is mostly due to the advanced metering infrastructure installation project, generation facility spending, replacing and expanding gas and electric distribution systems and improving the electric transmission infrastructure. (See "Capital Expenditures" below.)

Financing Activities

The Utility's cash flows from financing activities for 2006, 2005 and 2004 were as follows:

(in millions)	2006	2005	2004
Borrowings under accounts receivable facility and working capital facility	**$ 350**	$ 260	$ 300
Repayments under accounts receivable facility and working capital facility	**(310)**	(300)	–
Net issuance of commercial paper, net of discount of $2 million	**458**	–	–
Net proceeds from long-term debt issued	**–**	451	7,742
Net proceeds from energy recovery bonds issued	**–**	2,711	–
Long-term debt, matured, redeemed or repurchased	**–**	(1,554)	(8,402)
Rate reduction bonds matured	**(290)**	(290)	(290)
Energy recovery bonds matured	**(316)**	(140)	–
Preferred stock dividends paid	**(14)**	(16)	(90)
Common stock dividends paid	**(460)**	(445)	–
Preferred stock with mandatory redemption provisions redeemed	**–**	(122)	(15)
Preferred stock without mandatory redemption provisions redeemed	**–**	(37)	–
Common stock repurchased	**–**	(1,910)	–
Other financing activities	**38**	65	–
Net cash used by financing activities	**$(544)**	$(1,327)	$ (755)

In 2006, net cash used by financing activities decreased by approximately $783 million compared to 2005. This was mainly due to the following factors:

- The Utility had net issuances of $458 million in commercial paper, net of a $2 million discount, in 2006 with no similar amount in 2005.
- In 2005, the Utility repurchased $1.9 billion in common stock from PG&E Corporation. There were no common stock repurchases in 2006.
- The Utility received proceeds of $2.7 billion from the issuance of ERBs in 2005.
- In May 2005, the Utility borrowed $451 million from the California Infrastructure and Economic Development Bank, which was funded by the bank's issuance of Pollution Control Bonds Series A-G, with no similar borrowing in 2006.
- Approximately $316 million of ERBs matured in 2006 with only $140 million of maturities in 2005.
- The Utility borrowed $350 million from the accounts receivable facility during 2006, compared to $260 million in 2005.
- The Utility redeemed $122 million of preferred stock with no similar redemption in 2006.
- In 2005, the Utility redeemed $500 million and defeased $600 million of Floating Rate First Mortgage Bonds. The Utility also repaid $454 million under certain reimbursement obligations that the Utility entered into in April 2004, when its plan of reorganization became effective. There were no similar redemptions and repayments in 2006.

In 2005, net cash used by financing activities increased by approximately $572 million compared to 2004. This is mainly due to the following factors:

- Proceeds from long-term debt decreased by approximately $7.3 billion. In 2004, the Utility issued approximately $7.7 billion, net of issuance costs of $107 million, in long-term debt to fund its plan of reorganization. In 2005, only $451 million, net of issuance costs of $3 million, in long-term debt was incurred by the Utility related to the Pollution Control Bonds Series A-G.
- An aggregate of $2.7 billion in ERBs were issued in 2005 with no similar issuance in 2004.
- The Utility repaid $300 million in 2005 under its working capital facility, with no similar repayment in 2004.
- Approximately $140 million of ERBs matured in 2005 with no similar maturities in 2004.
- Long-term debt matured, redeemed or repurchased by the Utility decreased by approximately $6.8 billion in 2005. In 2004, repayments on long-term debt totaled approximately $8.4 billion, primarily to discharge pre-petition debt at the effective date of the plan of reorganization.
- In 2005, the Utility repurchased $1.9 billion in common stock from PG&E Corporation and paid $445 million in common stock dividends to PG&E Corporation and $31 million to PG&E Holdings, LLC, a wholly owned subsidiary of the Utility.
- In 2005, the Utility redeemed $159 million of preferred stock compared to $15 million in 2004.
- Approximately $100 million in customer deposits (included in Other Financing Activities in the table above) was received in 2005 with no similar amount in 2004.

PG&E CORPORATION

As of December 31, 2006, PG&E Corporation had stand-alone cash and cash equivalents of approximately $386 million. PG&E Corporation's sources of funds are dividends from and share repurchases by the Utility, issuance of its common stock and external financing. In 2006, the Utility paid a total cash dividend of $460 million to PG&E Corporation. In 2005, the Utility paid a total cash dividend of $445 million to PG&E Corporation and repurchased $1.9 billion of its common stock from PG&E Corporation. The Utility did not pay any dividends to, nor repurchase shares from, PG&E Corporation during 2004.

Operating Activities

PG&E Corporation's consolidated cash flows from operating activities consist mainly of billings to the Utility for services rendered and payments for employee compensation and goods and services provided by others to PG&E Corporation. PG&E Corporation also incurs interest costs associated with its debt.

PG&E Corporation's consolidated cash flows from operating activities for 2006, 2005 and 2004 were as follows:

(in millions)	**2006**	2005	2004
Net income	**$ 991**	$ 917	$ 4,504
Gain on disposal of NEGT (net of income tax benefit of $13 million in 2005 and income tax expense of $374 million in 2004; See Note 7 of the Notes to the Consolidated Financial Statements for details)	**—**	(13)	(684)
Net income from continuing operations	**991**	904	3,820
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, amortization, decommissioning and allowance for equity funds used during construction	**1,756**	1,698	1,497
Loss from retirement of long-term debt	**—**	—	65
Tax benefit from employee stock plans	**—**	50	41
Gain on sale of assets	**(11)**	—	(19)
Recognition of regulatory asset, net of tax	**—**	—	(4,900)
Deferred income taxes and tax credits, net	**(285)**	(659)	2,607
Other deferred charges and noncurrent liabilities	**151**	33	(519)
Other changes in operating assets and liabilities	**112**	383	(736)
Net cash provided by operating activities	**$2,714**	$2,409	$ 1,856

In 2006, the net cash provided by operating activities increased by $305 million compared to 2005, primarily due to an increase in the Utility's net cash provided by operating activities and tax refunds received by PG&E Corporation during the first and third quarters of 2006, with no similar refunds received during 2005.

In 2005, the net cash provided by operating activities increased by $553 million compared to 2004, primarily due to an increase in the Utility's net cash provided by operating activities.

Investing Activities
PG&E Corporation, on a stand-alone basis, did not have any material investing activities in the years ended December 31, 2006, 2005 and 2004.

Financing Activities
PG&E Corporation's cash flows from financing activities consist mainly of cash generated from debt refinancing and the issuance of common stock.

PG&E Corporation's cash flows from financing activities for 2006, 2005 and 2004 were as follows:

(in millions)	2006	2005	2004
Borrowings under accounts receivable facility and working capital facility	**$ 350**	$ 260	$ 300
Repayments under accounts receivable facility and working capital facility	**(310)**	(300)	–
Net issuance of commercial paper, net of discount of $2 million	**458**	–	–
Net proceeds from issuance of long-term debt	**–**	451	7,742
Net proceeds from issuance of energy recovery bonds	**–**	2,711	–
Long-term debt matured, redeemed or repurchased	**–**	(1,556)	(9,054)
Rate reduction bonds matured	**(290)**	(290)	(290)
Energy recovery bonds matured	**(316)**	(140)	–
Preferred stock with mandatory redemption provisions redeemed	**–**	(122)	(15)
Preferred stock without mandatory redemption provisions redeemed	**–**	(37)	–
Common stock issued	**131**	243	162
Common stock repurchased	**(114)**	(2,188)	(378)
Common stock dividends paid	**(456)**	(334)	–
Other	**3**	32	(91)
Net cash used by financing activities	**$(544)**	$(1,270)	$(1,624)

During 2006, PG&E Corporation's consolidated net cash used by financing activities decreased by approximately $726 million, compared to 2005, primarily due to the following factors, after consideration of the Utility's cash flows from financing activities:

- PG&E Corporation paid four quarterly common stock dividends in 2006, but made only three payments in 2005.
- In 2005, PG&E Corporation repurchased approximately $2.2 billion in common stock. There was no similar share repurchase in 2006, but PG&E Corporation paid certain additional payments of approximately $114 million to Goldman Sachs & Co., Inc. related to the prior year repurchase.

In 2005, PG&E Corporation's consolidated net cash used by financing activities decreased by approximately $354 million, compared to 2004, due to the following financing activities in addition to Utility financing activities:

- In 2005, PG&E Corporation paid $334 million in common stock dividends with no similar payment in 2004.
- In 2005, PG&E Corporation issued $81 million more in common stock than in 2004.
- In 2005, PG&E Corporation repurchased $2.2 billion in common stock while repurchasing only $378 million in common stock in 2004.

PG&E Corporation expects its $280 million in Convertible Subordinated Notes will remain outstanding until maturity in 2010.

CONTRACTUAL COMMITMENTS

The following table provides information about the Utility's and PG&E Corporation's contractual obligations and commitments at December 31, 2006. PG&E Corporation and the Utility enter into contractual obligations in connection with business activities. These obligations primarily relate to financing arrangements (such as long-term debt, preferred stock and certain forms of regulatory financing), purchases of transportation capacity, natural gas and electricity to support customer demand and the purchase of fuel and transportation to support the Utility's generation activities.

		Payment due by period			
(in millions)	Total	Less than one year	1–3 years	3–5 years	More than 5 years
Contractual Commitments:					
Utility					
Purchase obligations:					
Power purchase agreements(1):					
Qualifying facilities	**$16,238**	$1,672	$3,331	$2,693	$8,542
Irrigation district and water agencies	**325**	80	70	61	114
Renewable contracts	**4,356**	166	498	637	3,055
Other power purchase agreements	**919**	251	421	218	29
Natural gas supply and transportation	**1,138**	954	176	8	—
Nuclear fuel	**539**	135	152	101	151
Preferred dividends and redemption requirements(2)	**42**	8	17	17	—
Employee benefits:					
Pension(3)	**528**	176	352	—	—
Other commitments(4)	**142**	123	19	—	—
Advanced metering infrastructure	**17**	17	—	—	—
Operating leases	**109**	20	32	23	34
Long-term debt(5):					
Fixed rate obligations	**11,514**	297	1,188	1,045	8,984
Variable rate obligations	**1,738**	40	75	688	935
Other long-term liabilities reflected on the Utility's balance sheet under GAAP:					
Rate reduction bonds(6)	**302**	302	—	—	—
Energy recovery bonds(7)	**2,612**	435	870	891	416
Capital lease obligations(8)	**553**	50	100	100	303
PG&E Corporation					
Long-term debt(5):					
Convertible subordinated notes	**372**	27	53	292	—
Operating leases	**13**	3	5	5	—
Canadian natural gas pipeline firm transportation contracts(9)	**128**	2	18	16	92

(1) This table does not include DWR allocated contracts because the DWR is currently legally and financially responsible for these contracts and payments.

(2) Preferred dividend and redemption requirement estimates beyond 5 years do not include nonredeemable preferred stock dividend payments as these continue in perpetuity.

(3) PG&E Corporation's and the Utility's funding policy is to contribute tax deductible amounts, consistent with applicable regulatory decisions, sufficient to meet minimum funding requirements. Contribution estimates after 2007 will be driven by CPUC decisions. See further discussion under "Regulatory Matters."

(4) Includes commitments for capital infusion agreements for limited partnership interests in the aggregate amount of approximately $4 million, load-control and self-generation CPUC initiatives in the aggregate amount of approximately $123 million and contracts for local and long-distance telecommunications in the aggregate amount of approximately $15 million.

(5) Includes interest payments over the terms of the debt. See Note 4 of the Notes to the Consolidated Financial Statements for further discussion.

(6) Includes interest payments over the terms of the bonds. See Note 5 of the Notes to the Consolidated Financial Statements for further discussion of RRBs.

(7) Includes interest payments over the terms of the bonds. See Note 6 of the Notes to the Consolidated Financial Statements for further discussion of ERBs.

(8) See Note 17 of the Notes to the Consolidated Financial Statements for further discussion of the capital lease obligations.

(9) See Note 17 of the Notes to the Consolidated Financial Statements for further discussion of the PG&E Corporation's natural gas pipeline firm transportation contracts.

The Utility's contractual commitments include power purchase agreements (including agreements with qualifying facility co-generators, or QFs, irrigation districts and water agencies and renewable energy providers), natural gas supply and transportation agreements, nuclear fuel agreements, operating leases and other commitments that are discussed in Note 17 of the Notes to the Consolidated Financial Statements.

The contractual commitments table above excludes potential commitments associated with the conversion of existing overhead electric facilities to underground electric facilities. At December 31, 2006, the Utility was committed to spending approximately $211 million for these conversions. These funds are conditionally committed depending on the timing of the work, including the schedules of the respective cities, counties and telephone utilities involved. The Utility expects to spend approximately $50 million to $60 million each year in connection with these projects. Consistent with past practice, the Utility expects that these capital expenditures will be included in rate base as each individual project is completed and recoverable in rates charged to customers.

CAPITAL EXPENDITURES

The Utility's investment in plant and equipment totaled approximately $2.4 billion in 2006, $1.9 billion in 2005, and $1.6 billion in 2004. The Utility expects capital expenditures will total approximately $2.8 billion or greater in 2007. The Utility's weighted-average rate base in 2006 was $15.9 billion. Based on the estimated capital expenditures for 2007, the Utility projects a weighted-average rate base for 2007 of approximately $17.3 billion. Over the next five years, the Utility expects, subject to regulatory approval, to replace aging infrastructure and otherwise invest in plant and equipment to accommodate anticipated electricity and natural gas load growth and invest in the projects listed below.

Advanced Metering Infrastructure

In July 2006, the CPUC issued a decision approving the Utility's application to install an advanced metering infrastructure, known as the SmartMeter™ system, for virtually all of the Utility's electric and gas customers. This infrastructure enables the Utility to measure usage of electricity on a time-of-use basis and to charge demand-responsive rates. The goal of demand-responsive rates is to encourage customers to reduce energy consumption during peak demand periods and to reduce peak period procurement costs. Advanced meters can record usage in time intervals and be read remotely. The Utility began installation of the infrastructure in 2006 and expects to complete the installation throughout its service territory by the end of 2011.

The CPUC also approved the Utility's proposal to offer customers a new voluntary critical peak pricing billing option called "SmartRate" under which customers will be able to take advantage of electricity prices that vary by day and hour, potentially reducing their bills by shifting their energy use away from critical peak periods. By shifting energy demand away from critical peak periods, the Utility anticipates that it would need to purchase less power for critical peak periods.

The CPUC authorized the Utility to recover the $1.74 billion estimated SmartMeter™ project cost, including an estimated capital cost of $1.4 billion. The $1.74 billion amount includes $1.68 billion for project costs and approximately $54.8 million for costs to market the SmartMeter™ technology. In addition, the Utility can recover in rates 90% of up to $100 million in costs that exceed $1.68 billion without a reasonableness review by the CPUC. The remaining 10% will not be recoverable in rates. If additional costs exceed the $100 million threshold, the Utility may request recovery of the additional costs, subject to a reasonableness review.

PG&E Corporation and the Utility cannot predict whether or to what extent the anticipated benefits and cost savings of the advanced metering infrastructure project will be realized.

Diablo Canyon Steam Generator Replacement Project

In November 2005, the CPUC approved the Utility's replacement of the steam generators at the two nuclear operating units at Diablo Canyon, one in 2008 and one in 2009. The estimated cost of the steam generation replacement project, or SGRP, is $642 million, of which $165 million had been spent as of December 31, 2006, including progress payments on contracts for the eight steam generators the Utility has ordered.

To implement the SGRP, the Utility has obtained two coastal development permits from the California Coastal Commission to build temporary structures at Diablo Canyon to house the new generators as they are prepared for installation and for certain offloading activities. The Utility also has obtained a conditional use permit from San Luis Obispo County to store the old generators on site at Diablo Canyon. On January 10, 2007, the Coastal Law Enforcement Action Network filed a lawsuit in the Superior Court for the County of San Francisco against both the California Coastal Commission and the Utility alleging that the commission violated the California Coastal Act, the California Environmental Quality Act, and the San Luis Obispo Certified Local Coastal Program when it approved the permits without requiring the Utility to commit to undertake certain proposed or otherwise feasible mitigation measures. The complaint requests that the court (1) find that the approval of the permits was "illegal and invalid," (2) order the commission to set aside and vacate its approval, and (3) issue a permanent injunction to prohibit the Utility from engaging in any activity authorized by the permits until the commission complies with the judgment that the court may render. The complaint does not seek a temporary restraining order against the Utility. PG&E Corporation and the Utility believe that the permits were legally and validly approved and issued.

If the Utility's SGRP is delayed, the Utility could incur additional costs to operate and maintain the old steam generators until they can be replaced and to delay and extend project completion dates. If the Utility is not able to complete the SGRP, the Utility would be required to cease operations at Diablo Canyon and procure power from other sources when the generators are no longer operable in conformance with operating standards. The Utility would also have to pay for all work done in connection with the design and fabrication of the eight steam generators and a pro-rated profit up to the time the performance under the contracts is completed or the contracts are terminated.

New Generation Facilities

During 2006, the CPUC approved three contracts that provide for the construction of generation facilities to be owned and operated by the Utility:

- **Gateway Generating Station** — In June 2006, the CPUC authorized the Utility to acquire the equipment, permits, and contracts related to a partially completed 530-megawatt, or MW, power plant in Antioch, California, referred to as the Gateway Generating Station, or Gateway. The Utility completed the acquisition in November 2006. The CPUC authorized the Utility to recover approximately $295 million in capital costs to complete the construction of the facility as well as costs for its operation. On February 15, 2007, the CPUC approved the Utility's request to recover an additional approximately $75 million necessary to convert the plant from fresh water cooling to dry cooling in order to reduce the environmental impact of the facility and as a result of changes to Gateway's environmental permits. The Utility also has filed a request with the California Energy Commission, or CEC, to amend the facility's current permit to authorize the plant to be converted from fresh water cooling to dry cooling. The Utility expects that the CEC will issue a decision in the second quarter of 2007. Subject to obtaining the permit amendment from the CEC, meeting construction schedules, operational performance requirements and other conditions, the Utility estimates that it will complete construction of the Gateway facility and commence operations in 2009 at an estimated cost of approximately $370 million including expenditures related to the conversion to dry cooling.
- **Colusa Power Plant** — In November 2006, the CPUC approved an agreement for the development and construction of a 657-MW power plant to be located in Colusa County, California. The CPUC adopted an initial capital cost for the Colusa project that is equal to the sum of the fixed contract costs plus the Utility's estimated owner's costs and a contingency amount to account for the risk and uncertainty in the estimation of owner's costs. (Owner's costs include the Utility's expenses for legal, engineering and consulting services as well as the costs for internal personnel and overhead related to the project.) The CPUC also authorized the Utility to adjust the initial capital cost for the Colusa project to reflect any actual incentive payments made to, or liquidated damages received from, the contractors through notification to the CPUC but without a reasonableness review. Subject to obtaining required permits, meeting construction schedules, operational performance requirements and other conditions, it is anticipated that the Colusa project will commence operations in 2010 at an estimated cost of approximately $673 million.
- **Humboldt Bay Power Plant** — In November 2006, the CPUC also approved an agreement for the construction of a 163-MW power plant to re-power the Utility's existing power plant at Humboldt Bay, which is at the end of its useful life. The CPUC adopted an initial capital cost of the Humboldt Bay project equal to the sum of the fixed contract costs plus the Utility's estimated owner's costs, but limited the contingency amount for owner's costs to 5% of the fixed contract cost and estimated owner's costs. Subject to obtaining required permits, meeting construction

schedules, operational performance requirements and other conditions, it is anticipated that the Humboldt Bay project will commence operations in 2009 at an estimated cost of approximately $239 million.

The CPUC authorized the Utility to adjust the initial capital costs for the Colusa and Humboldt Bay projects to reflect any actual incentive payments made to, or liquidated damages received from, the contractors through notification to the CPUC but without a reasonableness review. The forecasted initial capital cost of the Colusa and Humboldt Bay projects will be trued-up in the Utility's next GRC following the commencement of operations of each plant to reflect actual initial capital costs. The true-up will reflect 50% of any actual cost savings for the Colusa project and all cost savings, if any, for the Humboldt Bay project. The Utility is authorized to seek recovery of additional capital costs incurred in connection with the Colusa and Humboldt Bay projects that are attributable to operational enhancements, but the request will be subject to the CPUC's review. Although the Utility is permitted to seek recovery of additional capital costs incurred in connection with the Humboldt Bay project subject to a reasonableness review, the Utility is not permitted to seek recovery of any other additional capital costs incurred in connection with the Colusa project.

OFF-BALANCE SHEET ARRANGEMENTS

For financing and other business purposes, PG&E Corporation and the Utility utilize certain arrangements that are not reflected in their Consolidated Balance Sheets. Such arrangements do not represent a significant part of either PG&E Corporation's or the Utility's activities or a significant ongoing source of financing. These arrangements enable PG&E Corporation and the Utility to obtain financing or execute commercial transactions on more favorable terms. For further information related to letter of credit agreements, the credit facilities, and PG&E Corporation's guarantee related to certain NEGT indemnity obligations, see Notes 4 and 17 of the Notes to the Consolidated Financial Statements.

CREDIT RISK

Credit risk is the risk of loss that PG&E Corporation and the Utility would incur if customers or counterparties failed to perform their contractual obligations. The Utility is exposed to a concentration of credit risk associated with receivables from the sale of natural gas and electricity to residential and small commercial customers in northern and central California. This credit risk exposure is mitigated by requiring deposits from new customers and from those customers whose past payment practices are below standard. A material loss associated with the regional concentration of retail receivables is not considered likely.

Additionally, the Utility has a concentration of credit risk associated with its wholesale customers and counterparties mainly in the energy industry, including other California investor-owned electric utilities, municipal utilities, energy trading companies, financial institutions, and oil and natural gas production companies located in the United States and Canada. This concentration of counterparties may impact the Utility's overall exposure to credit risk because counterparties may be similarly affected by economic or regulatory changes, or other changes in conditions. If a counterparty failed to perform on their contractual obligation to deliver electricity, then the Utility may find it necessary to procure electricity at current market prices, which may be higher than those prices contained in the contract. Credit losses attributable to receivables and electrical and gas procurement activities from both retail and wholesale customers and counterparties are expected to be recoverable from customers through rates and are not expected to have a material impact on earnings.

The Utility manages credit risk associated with its wholesale customers and counterparties by assigning credit limits based on evaluations of their financial condition, net worth, credit rating, and other credit criteria as deemed appropriate. Credit limits and credit quality are monitored periodically and a detailed credit analysis is performed at least annually. Further, the Utility relies on master agreements that require security, referred to as credit collateral, in the form of cash, letters of credit, corporate guarantees of acceptable credit quality, or eligible securities if current net receivables and replacement cost exposure exceed contractually specified limits.

The schedule below summarizes the Utility's net credit risk exposure to its wholesale customers and counterparties, as well as the Utility's credit risk exposure to its wholesale customers or counterparties with a greater than 10% net credit exposure, at December 31, 2006 and December 31, 2005:

(in millions)	Gross Credit Exposure Before Credit Collateral(1)	Credit Collateral	Net Credit Exposure(2)	Number of Wholesale Customer or Counterparties >10%	Net Exposure to Wholesale Customer or Counterparties >10%
December 31, 2006	**$255**	**$ 87**	**$168**	**2**	**$113**
December 31, 2005	$447	$105	$342	3	$165

(1) Gross credit exposure equals mark-to-market value on financially settled contracts, notes receivable and net receivables (payables) where netting is contractually allowed. Gross and net credit exposure amounts reported above do not include adjustments for time value or liquidity. The Utility's gross credit exposure includes wholesale activity only.

(2) Net credit exposure is the gross credit exposure minus credit collateral (cash deposits and letters of credit). For purposes of this table, parental guarantees are not included as part of the calculation.

CONTINGENCIES

PG&E Corporation and the Utility have significant contingencies that are discussed in Note 17 of the Notes to the Consolidated Financial Statements.

REGULATORY MATTERS

The Utility is subject to substantial regulation. Set forth below are matters pending before the CPUC, the FERC, and the Nuclear Regulatory Commission, or NRC, the resolution of which may affect the Utility's and PG&E Corporation's results of operations or financial condition.

2007 General Rate Case

On February 13, 2007, a proposed decision was issued by an administrative law judge, or ALJ, presiding over the Utility's 2007 GRC pending at the CPUC. On the same day, an alternate proposed decision was issued by the assigned CPUC Commissioner in the case. The ALJ's proposed decision recommends modifications to the proposed settlement agreement reached in August 2006 among the Utility, the CPUC's Division of Ratepayer Advocates, or DRA, and other parties, to resolve the issues raised by these parties and all revenue requirement-related issues raised in the 2007 GRC. The alternate proposed decision issued by the assigned Commissioner recommends that the proposed settlement agreement be approved.

Both the proposed decision and the alternate proposed decision accept the settlement agreement's proposal to set the Utility's GRC revenue requirements for a four-year period, 2007–2010. Under this proposal, the Utility's next GRC would be effective January 1, 2011. On October 19, 2006, the CPUC approved the Utility's request to make the revenue requirements ultimately adopted by the CPUC effective on January 1, 2007.

The settlement agreement proposes that the Utility's electric and gas service revenue requirements effective January 1, 2007 be set at approximately $2.9 billion for electric distribution, approximately $1 billion for gas distribution and $1 billion for electric generation operations, for a total of approximately $4.9 billion. The revenue requirement amounts set forth in the settlement agreement reflect an increase of $222 million in the Utility's electric distribution revenues, an increase of $20.5 million in gas distribution revenues and a decrease of $29.8 million in generation operation revenues, for an overall increase of $212.7 million (or 4.5%), over the 2006 authorized amounts. Under the settlement agreement, the Utility's revenue requirements are $181 million less than the amount requested in the Utility's original GRC application. Of this amount, approximately $95 million relates to depreciation expense, approximately $29 million relates to return and taxes associated with rate base, approximately $21 million relates to operating and maintenance expenses and customer service expenses and approximately $36 million relates to administrative and general expenses, payroll taxes and other miscellaneous expenses.

The settlement agreement also provides for annual attrition adjustments to authorized revenues of $125 million in each of 2008, 2009, and 2010 and an additional adjustment of $35 million in 2009 for the cost of a second refueling outage at Diablo Canyon. The attrition adjustment to authorized revenues for 2010 would be $125 million, less the one-time additional amount of $35 million from 2009, for a net increase of $90 million in 2010. The attrition adjustments discussed above incorporate some estimated benefits for the Utility's customers of cost savings attributable to the Utility's implementation of initiatives to achieve operating and cost efficiencies in 2008, 2009 and 2010. If the actual cost savings exceed the estimated benefits, such benefits would accrue to shareholders. Conversely, if these cost savings are not realized, earnings available for shareholders would be reduced.

The ALJ's proposed decision would modify the revenue requirements proposed in the settlement agreement in a number of areas, including hydroelectric operations, rate base and the treatment of certain tax issues. Instead of the $213 million total revenue requirement increase over 2006 authorized revenues proposed in the settlement agreement, the ALJ's proposed decision would result in a total revenue requirement increase of approximately $170 million over 2006 authorized revenues ($43 million less than the amount proposed in the settlement agreement). Both the ALJ's proposed decision and the alternate proposed decision would accept the attrition adjustments proposed in the settlement agreement.

The following table sets forth the amount of the changes to 2006 authorized revenue requirements, by category, that would result from the revenue requirements recommended in the proposed decision and in the alternate proposed decision and the differences between the resulting revenue requirement change:

(in millions)	Proposed Decision (Recommending Modification to Settlement Amounts)	Alternate Proposed Decision (Recommending Settlement Amounts)	Difference Between Recommended Amounts
Electric distribution	$199	$222	$(23)
Gas distribution	9	21	(12)
Electric generation	(38)	(30)	(8)
Total revenue requirement increase (decrease) for 2007:	$170	$213	$(43)

The CPUC rules of procedure generally require that a proposed decision have been issued at least 30 days before the CPUC can vote on the decision. The next scheduled meeting at which the CPUC could issue a final decision in the 2007 GRC will be held on March 15, 2007.

PG&E Corporation and the Utility are unable to predict when the CPUC will issue a final decision or whether the settlement agreement will be approved.

Electricity Generation Resources

Each California investor-owned electric utility is responsible to procure electricity to meet customer demand, plus applicable reserve margins, not satisfied from that utility's own generation facilities and existing electricity contracts. Each utility must submit a long-term procurement plan covering a 10-year period to the CPUC for approval. California legislation allows the California investor-owned utilities to recover their wholesale electricity procurement costs incurred in accordance with their CPUC-approved procurement plans. The Utility's forecasted costs under power purchase agreements and fuel costs are reviewed annually and recovered through the Energy Resource Recovery Account, or the ERRA, a balancing account designed to track and allow recovery of the difference between the authorized revenue requirement and actual costs incurred under the Utility's CPUC-authorized procurement plans. The CPUC performs periodic compliance reviews of the procurement activities recorded in the ERRA to ensure that the Utility's procurement activities are in compliance with its approved procurement plans. In addition, the CPUC will adjust retail electricity rates or order refunds, as appropriate, when the forecast aggregate over-collections or under-collections exceed 5% of a utility's prior year electricity procurement revenues (excluding amounts collected for the DWR contracts) for the length of a utility's resource commitment or 10 years, whichever is longer. The Chapter 11 Settlement Agreement also provides that the Utility will recover its reasonable costs of providing utility service, including power procurement costs.

The authorized revenue requirements for capital costs and non-fuel operating and maintenance costs for Utility-owned generation are addressed in the Utility's GRC. If the CPUC approves the 2007 GRC settlement agreement, the Utility's next GRC will not occur until 2011.

Cost Recovery for New Generation Resources

The CPUC decided that the utilities should be allowed to recover any above market or stranded costs of new generation resources from departing customers, as well as from their retail or "bundled" electricity customers, through the imposition of a non-bypassable charge. For a utility-owned generation facility, the duration of the stranded cost recovery period would be 10 years, beginning with commercial operations, and for a power purchase agreement, the duration would be 10 years or the term of the contract, whichever is less. At the end of this 10-year period, the Utility will still be able to collect any stranded costs from its current full-service customers, but no longer be able to charge departing customers for those costs. Contracts for renewable energy sources, however, are eligible for stranded cost recovery over the entire life of the contract. The utilities are allowed to justify a stranded cost recovery period longer than 10 years on a case-by-case basis. The implementation of the non-bypassable charge is being addressed in the CPUC's 2006 long-term procurement plan proceeding discussed below.

In July 2006, the CPUC issued a decision adopting a transitional policy to foster investment in new generation and directing the California investor-owned utilities to proceed expeditiously to procure new generation on behalf of all benefiting customers in an investor-owned utility's service territory. Under this transitional policy, for new generation purchased from third parties under power purchase agreements, the utilities may elect to allocate the net capacity costs (i.e., contract price less energy revenues) to all "benefiting customers" in the utilities' service territory, including existing direct access customers (i.e., former customers who choose to buy energy from an alternate service provider other than the regulated utilities) and customers of community choice aggregators (i.e., cities and counties who purchase and sell electricity for their local residents and businesses), rather than recovering stranded costs only from their bundled and departing customers.

If a utility elects to use the net capacity cost allocation method, the net capacity costs would be allocated for the term of the contract or 10 years, whichever is less, starting on the date the new generation unit comes on line. Under this allocation mechanism, the right to receive energy under the contract is auctioned off to maximize the energy revenue and minimize the net capacity costs that would be subject to allocation. If no bids are accepted for the energy rights, the utility would retain the rights to the energy and would value it at spot market prices for the purposes of determining the net capacity costs to be allocated until the next periodic auction. Specific implementation details for the energy rights auction are also being addressed in the 2006 long-term procurement plan proceeding discussed below, and the CPUC noted that the evolution of a new market-based system may change the mechanics of this cost allocation method.

2006 Long-Term Procurement Plan

In December 2006, the Utility submitted its 2006 long-term procurement plan to the CPUC for approval of its 2007–2016 electric energy and electric fuel procurement plans. A decision is expected by the end of 2007. The plan forecasts demand for up to an additional 2,300 MW of new dispatchable and operationally flexible capacity starting 2011. The Utility's proposed long-term plan is designed to provide reliable service, promote environmentally preferred resources and manage customer costs. The Utility is proposing cost recovery and reasonableness review protection and requests approval for:

- short, medium and long-term procurement implementation authority;
- a nuclear fuel supply plan;
- a gas supply plan and asset plan; and
- an electric and gas price risk hedging plan.

The Utility anticipates that after CPUC approval of its procurement plan, the Utility would be expected to complete a competitive request for offer from providers of all potential sources of new generation (e.g., conventional or renewable resources to be provided under turnkey developments, buyouts, or power purchase agreements) to meet the Utility's projected need for electricity resources. PG&E Corporation and the Utility cannot predict whether the CPUC will approve the Utility's proposed plan or whether any of the new generation resources commitments will be Utility-owned generation projects.

Resource Adequacy

California investor-owned electric utilities (and most other entities that serve electricity customers under the jurisdiction of the CPUC) are required to meet certain capacity planning requirements and demonstrate they have met those targets through annual and monthly compliance filings. There is a general, or system, requirement to achieve an electricity planning reserve margin of 15% to 17% above forecasted peak electricity usage or "load." Within that general requirement, a certain portion must be met within predefined local areas (i.e., areas on the system that are transmission constrained). In December 2006, the CPUC outlined additional issues to be considered in future phases of the CPUC's resource adequacy proceeding which establishes planning requirements. Issues in the next phase include the possibility of increasing the electricity planning reserve margin requirement and instituting longer-term requirements.

If the CPUC determines that a utility or other load serving entity has not met its requirement in a particular year, the CPUC can impose penalties in an amount determined by the CPUC. The penalty for failure to procure sufficient system resource adequacy capacity is equal to three times the cost of securing new resources, which the CPUC set at $120 per kilowatt-year, or kW-year. The penalty for failure to meet local resource adequacy requirements is equal to $40 per kW-year. In addition to penalties, entities that fail to meet resource adequacy requirements may be assessed the cost of backstop procurement by the CAISO to fulfill their resource adequacy target levels. The Utility's proposed 2007–2016 long-term procurement plan forecasts that the Utility will be able to meet future resource adequacy requirements.

Qualifying Facility Power Purchase Agreements

The CPUC is considering various policy and pricing issues related to power purchased from QFs in rulemaking proceedings. During 2006, the Utility and the Independent Energy Producers, or IEP, on behalf of certain QFs, entered into, and the CPUC approved, a settlement agreement and a QF contract amendment to resolve these issues for the settling parties. As of December 31, 2006, the CPUC approved amendments for 122 QFs projects which reduces the Utility's energy payments and establishes a new five-year fixed pricing option for QFs that do not use natural gas as their fuel source. The IEP settlement agreement also resolves certain energy crisis claims by the Utility against a subset of the settling QFs that are pending in a different CPUC proceeding. Such claims remain unresolved for those QFs which did not participate in the settlement.

As described in Note 17 in the Notes to the Consolidated Financial Statements, the obligations under some of the amended QF contracts qualify for capital lease accounting.

Renewable Energy Contracts

California law, as amended in September 2006, by the enactment of Senate Bill 107, established the renewables portfolio standard, or RPS program. The RPS program requires each California retail seller of electricity, except municipal utilities (other than Community Choice Aggregators), to increase its purchases of eligible renewable energy (such as biomass, small hydro, wind, solar, and geothermal energy) by at least 1% of its retail sales per year so that the amount of electricity purchased from eligible renewable resources equals at least 20% of its total retail sales by the end of 2010. "Flexible compliance" rules, under the RPS program, allow a retail seller to satisfy and defer (for up to three years) its current year RPS requirements by signing contracts with renewable energy suppliers for future deliveries of renewable power. These rules also allow the CPUC to excuse noncompliance with the RPS targets if a retail seller is able to demonstrate good cause. Senate Bill 107, which became effective January 1, 2007, continues to permit use of flexible compliance rules and directs the CPUC to adopt flexible compliance rules that will apply to all years, including years before and after a retail seller meets the 20% RPS target. Senate Bill 107 also excuses retail sellers from the 20% RPS requirement if there is insufficient transmission capacity to deliver that power to California end-users.

In October 2006, the CPUC adopted rules for reporting and determining whether the RPS requirements have been met. The CPUC's decision addresses existing flexible compliance rules applicable to procurement through 2009, allowing an excused 2009 deficit to be fulfilled by the end of 2012. The CPUC also stated that a retail seller that has reached the 20% RPS target in a given year, but that had not yet fulfilled deferred compliance from prior years, must continue to increase its procurement in subsequent years until the deferred compliance is satisfied or is otherwise excused by the CPUC. The October 2006 order, which was issued prior to the effective date of Senate Bill 107, reiterated prior CPUC decisions in stating that the 20% RPS target must be met with actual eligible energy deliveries in 2010, but acknowledged that Senate Bill 107 changed flexible compliance requirements and further stated that that the CPUC would address the application of flexible compliance rules to 2010 and beyond in a future decision after the statute's effective date.

Currently, power from eligible renewable energy resources comprises approximately 12% of the Utility's retail sales. The Utility expects to comply with its 2004, 2005, 2006 and 2007 annual RPS targets. Although the Utility expects it will achieve the 20% target using the flexible compliance rules by 2010, actual deliveries of renewable power may not comprise 20% of its bundled retail sales by 2010 due to such factors as the time required for the construction of new generation facilities and/or needed transmission capacity. Failure to satisfy the RPS targets may result in a penalty of five cents per kilowatt hour with an annual penalty cap of $25 million. The exact amount of any penalty and conditions under which it would be applied is subject to the CPUC's review of the circumstances for under-delivery. With the flexible compliance rules that have been adopted to date by the CPUC, the Utility does not expect to incur penalties in the forecast timeframe of 2007 to 2009. The Utility anticipates, given the clear language of Senate Bill 107 requiring that flexible compliance rules "shall apply to all years, including years before and after" a retail seller reaches the 20% target, that the CPUC will extend existing flexible compliance rules to 2010 and future years, and on that basis do not expect to incur penalties in 2010. However, an Assembly Bill has been introduced in the California Legislature for consideration in 2007 to increase the RPS requirement to 33% of total retail sales by the end of 2020. The Utility is unable to predict whether this bill will be passed or whether the higher RPS target could be met.

The CPUC has adopted a procedure to enable the utilities to recover the cost of electric transmission and distribution facilities necessary to interconnect renewable energy resources if those costs cannot be recovered in federally approved rates. In 2007, the Utility will continue to plan for and begin implementation of various transmission projects to improve access to renewable energy resources, among other purposes.

FERC Transmission Rate Case

The Utility's electric transmission revenues and wholesale and retail transmission rates are subject to authorization by the FERC. In August 2006, the Utility filed an application with the FERC requesting an annual transmission revenue requirement of approximately $719 million, effective October 1, 2006. The proposed rates represent an increase of approximately $113 million over current authorized revenue requirements. In September 2006, the FERC issued an order accepting the Utility's rate application, suspending the requested rate changes for five months to become effective March 1, 2007, subject to refund. The FERC also ordered the Utility and interveners in the case to engage in settlement discussions to be supervised by a settlement judge.

On February 15, 2007, the Utility submitted an offer of settlement reached by the parties and requested that the settlement judge recommend that the FERC approve the settlement. The settlement proposes to set the Utility's transmission retail revenue requirements at $674 million, an increase of approximately $68 million over current authorized revenue requirements. If the FERC approves the proposed settlement, the revenue requirement changes will be deemed to have been effective as of March 1, 2007. The Utility would refund any over-collected amounts, with interest, to customers.

PG&E Corporation and the Utility are unable to predict what amount of revenue requirements the FERC will authorize, when a final decision will be received from the FERC, or the impact that it will have on their results of operations.

Natural Gas Transmission and Storage Rate Case

The Utility's gas transmission and storage services, rates and market structure are subject to authorization by the CPUC. In December 2004, the CPUC approved the Gas Accord III, which set rates, terms and conditions through December 31, 2007, for transmission services, and through March 31, 2008, for storage services.

The Utility is obligated to file a new rate case proposing gas transmission and storage rates and terms and conditions of service, for the period commencing January 1, 2008. The Utility currently is scheduled to submit that filing on March 15, 2007. In the event the CPUC does not issue a final decision approving new rates effective January 1, 2008, the Gas Accord III provides that the rates and terms and conditions of service in effect as of December 31, 2007, will remain in effect, with an automatic 2% escalation in the rates as of January 1, 2008.

Under the Gas Accord III, the costs associated with the Utility's local gas transportation and gas storage assets that are used for service to core customers are recovered through balancing account mechanisms that adjust for the difference between actual usage and forecast usage. In addition, approximately 65% of the costs associated with the Utility's backbone gas transmission system that is used to serve core customers are recovered through fixed charges. The remaining 35% of these costs are recoverable through volumetric charges. Revenues from these charges vary depending on the level of throughput volume. The costs that are recoverable through balancing accounts or fixed reservation charges account for approximately 45% of the Utility's total revenue requirement for gas transmission and storage. The remainder of the Utility's gas transmission and storage costs are recovered from core customers through volumetric charges and from non-core customers under firm or interruptible transmission or storage contracts. The Utility's recovery of this portion of its costs depends on the level of throughput volume, gas prices, and the extent to which non-core customers contract for firm services.

Spent Nuclear Fuel Storage Proceedings

Under the Nuclear Waste Policy Act of 1982, the Department of Energy, or the DOE, is responsible for the transportation and permanent storage and disposal of spent nuclear fuel and high-level radioactive waste. The Utility has contracted with the DOE to provide for the disposal of these materials from Diablo Canyon. Under the contract, if the DOE completes a storage facility by 2010, the earliest that Diablo Canyon's spent fuel would be accepted for storage or disposal is thought to be 2018. Under current operating procedures, the Utility believes that the existing spent fuel pools (which include newly constructed temporary storage racks) have sufficient capacity to enable the Utility to operate Diablo Canyon until approximately 2010 for Unit 1 and 2011 for Unit 2. After receiving a permit from the NRC in March 2004, the Utility began building an on-site dry cask storage facility to store spent fuel through at least 2024. The Utility estimates it could complete the dry cask storage project in 2008. The NRC's March 2004 decision, however, was appealed by various parties, and the U.S. Court of Appeals for the Ninth Circuit, or Ninth Circuit, issued a decision in 2006 that requires the NRC to consider the environmental consequences of a potential terrorist attack at Diablo Canyon as part of the NRC's supplemental assessment of the dry cask storage permit. The Utility may incur significant additional expenditures if the NRC decides that the Utility must change the design and construction of the dry cask storage facility. If the Utility is unable to complete the dry cask storage facility, or if construction is delayed beyond 2010, and if the Utility is otherwise unable to increase its on-site storage capacity, it is possible that the operation of Diablo Canyon may have to be curtailed or halted as early as 2010 with respect to Unit 1, and 2011 with respect to Unit 2, and until such time as additional spent fuel can be safely stored.

As a result of the DOE's failure to develop a permanent storage facility, the Utility has been required to incur substantial costs for planning and developing on-site storage options for spent nuclear fuel as described above at Diablo Canyon as well as at the retired nuclear facility at Humboldt Bay, or Humboldt Bay Unit 3. The Utility is seeking to recover these costs from the DOE on the basis that the DOE has breached its contractual obligation to move used nuclear fuel from Diablo Canyon and Humboldt Bay Unit 3 to a national repository beginning in 1998. Any amounts recovered from the DOE will be credited to customers. In October 2006, the U.S. Court of Federal Claims issued a decision awarding approximately $42.8 million of the $92 million incurred by the Utility through 2004. The Utility will seek recovery of costs incurred after 2004 in future lawsuits against the DOE. In January 2007, the Utility filed a notice of appeal of the U.S. Court of Federal Claims' decision in the U.S. Court of Appeals for the Federal Circuit seeking to increase the amount of the award and challenging the court's finding the Utility would have had to incur some of the costs for the on-site storage facilities even if the DOE had complied with the contract. If the court's decision is not overturned or modified on appeal, it is likely that the Utility will be unable to recover all of its future costs for on-site storage facilities from the DOE. However, reasonably incurred costs related to the on-site storage facilities are, in the case of Diablo Canyon, recoverable through rates and in the case of Humboldt Bay Unit 3, recoverable through its decommissioning trust fund.

PG&E Corporation and the Utility are unable to predict the outcome of this appeal or the amount of any additional awards the Utility may receive.

Defined Benefit Pension Plan Contribution

In June 2006, the CPUC approved the Utility's recovery of revenue requirements associated with annual contributions to fund the Utility's pension plan from 2006 to 2009. On a projected basis, these contributions are expected to bring the pension plan trust to fully funded status as of January 1, 2010.

In July 2006, the Utility made the 2006 authorized net pension contribution of $250 million funded by the authorized $155 million revenue requirement attributable to the Utility's distribution and generation operations, or GRC lines of business. Approximately $20 million of the $250 million contribution relates to revenue requirements for gas transmission and storage, electric transmission, and nuclear decommissioning, which have been or will be addressed in other CPUC or FERC proceedings. The remaining 2006 contribution amount will be capitalized and recovered in future periods. Additional pension contributions of $40 million associated with the 1994 voluntary retirement incentive, $3 million for PG&E Corporation participants, and $1 million for interest on the net pension contributions were also made during the year ended December 31, 2006.

For 2007, 2008 and 2009, the annual pension-related revenue requirement attributable to the GRC lines of business will decrease to approximately $98 million. If the proposed settlement agreement in the Utility's 2007 GRC is approved, the Utility would be authorized to fund a net pension contribution of $153 million in 2010, with an associated revenue requirement attributable to the GRC lines of business of approximately $98 million.

Delayed Billing Investigation

In February 2005, the CPUC issued a ruling opening an investigation into the Utility's billing and collection practices and credit policies. The investigation was initiated at the request of The Utility Reform Network, or TURN, after the CPUC's January 2005 decision that characterized the definition of "billing error" in a revised Utility tariff to include delayed bills and Utility-caused estimated bills as being consistent with "existing CPUC policy, tariffs and requirements." The Utility contended that prior to the CPUC's January 2005 decision, "billing error" under the Utility's former tariffs did not encompass delayed bills or Utility-caused estimated bills. The Utility petitioned the California Court of Appeals to review the CPUC's decision denying rehearing of its January 2005 decision. In December 2006, the Court of Appeals summarily rejected the Utility's petition; the Utility did not appeal that rejection to the California Supreme Court.

The CPUC's Consumer Protection and Safety Division, or CPSD, and TURN have submitted their reports to the CPUC concluding that the Utility violated applicable tariffs related to delayed and estimated bills and recommended refunds in the current amounts of approximately $54 million and $36 million, respectively, plus interest at the three-month commercial paper interest rate. The two refunds are not additive. The CPSD also recommended that the Utility pay fines of $6.75 million, while TURN recommends fines in the form of a $1 million contribution to REACH (Relief for Energy Assistance through Community Help). Both the CPSD and TURN recommend that refunds and fines be funded by shareholders.

The Utility responded that its tariff interpretation was in good faith, and was repeatedly supported by Commission staff. It argued that the CPUC should exercise its discretion not to order refunds, and that any ordered refunds should be treated in accordance with adopted ratemaking, under which the significant majority of the costs of any refunds would be reflected in future rates borne by the Utility's general body of customers. It argued that its behavior does not warrant fines or penalties. On February 15, 2007, the CPUC extended the date by which it must issue a final decision in this investigative matter to August 26, 2007.

On February 20, 2007, the ALJ presiding over the proceeding issued a "presiding officer" decision. Although the decision found that penalties were not warranted, the decision orders the Utility to refund, at shareholder expense, approximately $23 million to customers for "illegal backbill charges" relating to estimated and delayed bills that were charged to customers in excess of the time limits in the Utility's tariff. The decision also orders the Utility to refund reconnection fees and "pay credits to certain customers whose service was shutoff for nonpayment of illegal backbills."

Under CPUC rules, parties in an adjudicatory proceeding may appeal the presiding officer's decision within 30 days. In addition, any Commissioner may request review of the presiding officer's decision within 30 days of the date of issuance. If no appeal or request for review is filed within 30 days, the presiding officer's decision will become the final CPUC decision. The Utility intends to appeal the presiding officer's decision.

PG&E Corporation and the Utility do not expect that the outcome of this matter will have a material adverse effect on their financial condition or results of operations.

Energy Efficiency Rulemaking

In April 2006, the CPUC began a proceeding to consider establishing new energy efficiency policies and programs, including mechanisms that would provide incentives or impose penalties on the investor-owned utilities depending on the extent to which the utilities successfully implement their 2006–2008 energy efficiency programs and meet the CPUC's targets for reducing customers' demand for electricity and natural gas. Under the Utility's current proposed incentive mechanism, if the Utility achieved 80% to 100% of the CPUC's demand reduction targets, 80% of the net present value of energy efficiency programs (i.e., the net benefits) would accrue to customers and 20% of the net benefits would accrue to shareholders. If the Utility exceeds 100% of the CPUC's targets, the Utility's shareholders would receive 30% of the additional net benefits attributable to the portion of demand reduction that exceeds 100% of the CPUC's targets and the Utility's customers would receive the remaining 70%. Other parties have proposed that the Utility begin earning incentives only when the Utility reached 85% of the CPUC's targets and obtain earnings ranging from only 1% to 3% of the net benefits. All parties have proposed penalties for poor performance in achieving the CPUC's targets. The Utility has proposed that if it achieves less than 40% of the CPUC's targets, the Utility would provide customers any shortfall between the revenues received in rates for energy efficiency and benefits obtained through the energy efficiency programs. Other parties have proposed that penalties be imposed if the Utility achieves less than 50% to 85% of the CPUC's targets.

It is anticipated that the CPUC will issue a final decision on the adoption of a shareholder incentive and penalty mechanism in the first half of 2007. Depending upon the ratemaking method adopted by the CPUC, actual shareholder incentives or penalties may not be realized for several years. In addition to proposed mechanisms for shareholder incentives or penalties, other issues to be considered include evaluation, measurement and verification of the Utility's energy efficiency implementation results, examining energy savings arising from water efficiency (through reduced water pumping or treatment) and planning for energy efficiency programs to be implemented in 2009–2011.

PG&E Corporation and the Utility are unable to predict what rules and policies the CPUC may ultimately adopt and what impact the adopted shareholder incentive and penalty mechanism may have on their financial condition and results of operations.

Catastrophic Event Memorandum Account Application

From late December 2005 to early January 2006, winter storms disrupted service to approximately 1.5 million electric customers and damaged the Utility's electric distribution facilities and generation facilities. In addition, from mid- to late July 2006, all parts of the Utility's service territory experienced unusually high temperatures, contributing to a "heat storm" that disrupted service to approximately 1.2 million electric customers and damaged the Utility's electric distribution facilities. Total costs to restore service and repair facilities from these events, including work completed in 2006 and work that is scheduled to be completed in 2007, are expected to amount to a total of $62 million.

The CPUC allows utilities to recover the reasonable costs of responding to catastrophic events through a catastrophic event memorandum account, or CEMA. The CEMA tariff authorizes recovery of costs when a catastrophic event has been declared a disaster or state of emergency by competent state or federal authorities. The California Governor proclaimed a state of emergency to exist due to the damage caused by the winter storms. The United States Department of Agriculture and several county governments declared a disaster designation or local emergency for several of California's counties as a result of the July "heat storm." Among other issues to be decided in a CEMA proceeding, the CPUC conducts a review to determine whether the costs were prudently incurred and incremental to revenue requirements previously authorized by the CPUC.

In November 2006, the Utility filed its 2006 CEMA application for the winter storms and the July 2006 "heat storm" requesting rate recovery of approximately $45 million in 2008 rates for recovery of the CEMA costs. In December 2006, DRA and TURN filed protests to the Utility's 2006 application indicating their intention to review final recorded 2006 data and investigate whether the costs included in the Utility's request are incremental to costs already included in rates. In addition, the assigned ALJ has raised doubts about the sufficiency of the July heat storm disaster declarations to trigger eligibility for CEMA relief. In January 2007, the Utility filed its brief on this issue.

PG&E Corporation and the Utility are unable to predict whether the CPUC will approve the CEMA application or the amount of any potential recovery.

RISK MANAGEMENT ACTIVITIES

The Utility and PG&E Corporation, mainly through its ownership of the Utility, are exposed to market risk, which is the risk that changes in market conditions will adversely affect net income or cash flows. PG&E Corporation and the Utility face market risk associated with their operations, financing arrangements, the marketplace for electricity, natural gas, electricity transmission, natural gas transportation and storage, other goods and services and other aspects of their business. PG&E Corporation and the Utility categorize market risks as price risk and interest rate risk.

As long as the Utility can conclude that it is probable its reasonably incurred wholesale electricity procurement costs are recoverable through the regulatory mechanisms described above under "Regulatory Matters – Electricity Generation Resources," fluctuations in electricity prices will not affect earnings but may impact cash flows. The Utility's natural gas procurement costs for its core customers are recoverable through the CPIM and other ratemaking mechanisms, as described below. The Utility's natural gas transportation and storage costs for core customers are also fully recoverable through a ratemaking mechanism. However, the Utility's natural gas transportation and storage costs for non-core customers may not be fully recoverable. The Utility is subject to price and volumetric risk for the portion of intrastate natural gas transportation and storage capacity that has not been sold under long-term contracts providing for the recovery of all fixed costs through the collection of fixed reservation charges. The Utility sells most of its capacity based on the volume of gas that the Utility's customers actually ship, which exposes the Utility to volumetric risk. Movement in interest rates can also cause earnings and cash flow to fluctuate.

The Utility actively manages market risks through risk management programs designed to support business objectives, discourage unauthorized risk-taking, reduce commodity cost volatility and manage cash flows. The Utility uses derivative instruments only for non-trading purposes (i.e., risk mitigation) and not for speculative purposes. The Utility's risk management activities include the use of energy and financial instruments, such as forward contracts, futures, swaps, options, and other instruments and agreements, most of which are accounted for as derivative instruments. Some contracts are accounted for as leases.

The Utility estimates fair value of derivative instruments using the midpoint of quoted bid and asked forward prices, including quotes from brokers, and electronic exchanges, supplemented by online price information from news services. When market data is not available, the Utility uses models to estimate fair value.

PRICE RISK

Electricity Procurement

The Utility relies on electricity from a diverse mix of resources, including third-party contracts, amounts allocated under DWR contracts and its own electricity generation facilities. When customer demand exceeds the amount of electricity that can be economically produced from the Utility's own generation facilities plus net energy purchase contracts (including DWR contracts allocated to the Utility's customers), the Utility will be in a "short" position. In order to satisfy the short position, the Utility purchases electricity in the hour- and day-ahead markets or in the forward markets (the majority of which occurs through contracts with delivery times ranging up to five or six years forward). The FERC has adopted a "soft" cap on energy prices of $400 per megawatt hour, or MWh, that applies to the spot market (i.e., real-time, hour-ahead and day-ahead markets) throughout the Western Electricity Coordinating Council area. This "soft" cap also applies to prices for ancillary services within the markets administered by the CAISO. (A "soft" cap allows market participants to submit bids that exceed the bid cap if adequately justified, but does not allow such bids to set the market clearing price. A "hard" cap prohibits bids that exceed the cap, regardless of the seller's costs.)

When the Utility's supply of electricity from its own generation resources plus net energy purchase contracts exceeds customer demand, the Utility is in a "long" position. When the Utility is in a long position, the Utility sells the excess supply in the hour- and day-ahead markets or in the forward markets. Price risk is associated with the uncertainty of prices when buying or selling to reduce open positions (short or long positions).

The amount of electricity the Utility needs to meet the demands of customers that is not satisfied from the Utility's own generation facilities, existing purchase contracts or DWR contracts allocated to the Utility's customers, is subject to change for a number of reasons, including:

- periodic expirations of existing electricity purchase contracts, or entering into new purchase contracts;
- fluctuation in the output of hydroelectric and other renewable power facilities owned or under contract;
- changes in the Utility's customers' electricity demands due to customer and economic growth, weather, implementation of new energy efficiency and demand response programs, direct access, and community choice aggregation;
- the acquisition, retirement or closure of generation facilities; and
- changes in market prices that make it more economical to purchase power in the market rather than use the Utility's existing resources.

In addition, a failure to perform by any of the counterparties to electricity purchase contracts or the DWR allocated contracts would reduce the size of the Utility's electricity supply portfolio. To the extent such a failure resulted in the Utility being in a short position the Utility may find it necessary to procure electricity at then-current market prices, which may be higher than those prices contained in the contract. In particular, Calpine Corporation and certain of its subsidiaries that have filed Chapter 11 petitions, or Calpine, sought to reject certain power purchase contracts under which they provide electricity needed by the Utility's customers. A federal district court ruled that it lacks jurisdiction to authorize Calpine to reject the contracts, finding that the FERC has exclusive jurisdiction. Calpine has appealed that decision. In the interim, the Utility and Calpine reached a settlement that replaces the contracts entered into between Calpine and the Utility, but a DWR allocated contract that supplies approximately 11% of the electricity needed by the Utility's customers still remains at issue in Calpine's appeal. The Utility has contingency plans to ensure that it has adequate resources under contract or available if Calpine succeeds in terminating the DWR allocated contract.

Lengthy, unexpected outages of the Utility's generation facilities or other facilities from which it purchases electricity also could cause the Utility to be in a short position. It is possible that the operation of Diablo Canyon may have to be curtailed or halted as early as 2010, if suitable storage facilities are not available for spent nuclear fuel, which would cause a significant increase in the Utility's short position (see "Spent Nuclear Fuel Storage Proceedings" above). If any of these events were to occur, the Utility may find it necessary to procure electricity from third parties at then-current market prices.

The Utility expects to satisfy at least some of the forecasted short position through the CPUC-approved contracts it has entered into in accordance with its CPUC-approved long-term procurement plan covering 2005 through 2014. As discussed above under "Regulatory Matters – Electricity Generation Resources," there are regulatory mechanisms in place to permit the Utility to recover costs incurred under these contracts from customers. As long as these cost recovery mechanisms remain in place, adverse market price changes are not expected to impact the Utility's net income. The Utility is at risk to the extent that the CPUC may in the future disallow portions or the full costs of procurement transactions. Additionally, market price changes could impact the timing of the Utility's cash flows.

Natural Gas Procurement (Electric Portfolio)

A portion of the Utility's electric portfolio is exposed to natural gas price risk. The Utility manages this risk in accordance with its risk management strategies included in electricity procurement plans approved by the CPUC. The CPUC has approved the Utility's electric portfolio gas hedging plan. The expenses associated with the hedging plan are expected to be recovered in the ERRA. (See the "Electricity Generation Resources" section of this MD&A.)

Natural Gas Procurement (Core Customers)

The Utility generally enters into physical and financial natural gas commodity contracts from one to twelve months in length to fulfill the needs of its retail core customers. Changes in temperature cause natural gas demand to vary daily, monthly and seasonally. Consequently, significant volumes of gas may be purchased in the monthly and, to a lesser extent, daily spot market to meet such varying demand. The Utility's cost of natural gas purchased for its core customers includes the commodity cost, the cost of Canadian and interstate transportation, intrastate gas transmission and storage costs.

Under the CPIM, the Utility's purchase costs for a fixed twelve-month period are compared to an aggregate market-based benchmark based on a weighted average of published monthly and daily natural gas price indices at the points where the Utility typically purchases natural gas. Costs that fall within a tolerance band, which is 99% to 102% of the benchmark, are considered reasonable and are fully recovered in customers' rates. One-half of the costs above 102% of the benchmark are recoverable in customers' rates, and the Utility's customers receive, in their rates, three-quarters of any savings resulting from the Utility's cost of natural gas that is less than 99% of the benchmark. The shareholder award is capped at the lower of 1.5% of total natural gas commodity costs or $25 million. While this cost recovery mechanism remains in place, changes in the price of natural gas are not expected to materially impact net income.

Under the Utility's hedging plan for the winters of 2005–2008, core customers paid the cost of and received any payouts from these hedges as these transactions are handled outside of the CPIM. The Utility is at risk to the extent that the CPUC may disallow portions of the hedging cost based on its subsequent review of the Utility's compliance with the plan filed with the CPUC.

In December 2006, the Utility entered into a settlement agreement with three major consumer advocate groups that represent the interest of core customers, including the CPUC's DRA, Aglet Consumer Alliance, and TURN. The settlement is subject to CPUC approval. A decision by the CPUC is expected in the second quarter of 2007. If approved, the proposed settlement would establish a long-term hedge program outside of the CPIM for up to a three-year rolling horizon. The settlement agreement also provides that the Utility would consult with an advisory group, consisting of members of the consumer advocate groups, and would submit its annual hedging plan to the CPUC for approval. CPUC pre-approval of the annual implementation plans is intended to assure that the Utility's hedging costs will be recovered from its core procurement customers as long as the CPUC finds that the Utility implemented its hedges in accordance with the pre-approved plan. Since the settlement agreement proposes that the Utility's portfolio hedging activities would be conducted entirely outside of the CPIM, the CPIM would be modified so that 80%, instead of 75%, of any cost savings below the tolerance band would be shared with customers and the Utility would retain 20%, instead of 25%, of any cost savings.

Nuclear Fuel

The Utility purchases nuclear fuel for Diablo Canyon through contracts with terms ranging from two to five years. These long-term nuclear fuel agreements are with large, well-established international producers in order to diversify its commitments and provide security of supply. Nuclear fuel costs are recovered from customers through the ERRA balancing account (see "Regulatory Matters – Electricity Generation Resources" above) and therefore changes in nuclear fuel prices are not expected to materially impact net income.

Natural Gas Transportation and Storage

The Utility faces price and volumetric risk for the portion of intrastate natural gas transportation and storage capacity that is used to serve non-core customers. This risk is mitigated to the extent these non-core customers contract for transportation and storage services under firm service agreements that provide for recovery of fixed costs through the collection of fixed reservation charges. The reservation charges under such contracts typically cover approximately 65% of the Utility's fixed costs. Price risk and volumetric risk result from variability in the price of and demand for natural gas transportation and storage services, respectively. Transportation and storage services are sold at both tariffed rates and competitive market-based rates within a cost-of-service tariff framework.

The Utility uses value-at-risk to measure the shareholder's exposure to price and volumetric risks that could impact revenues due to changes in market prices, customer demand and weather. Value-at-risk measures this exposure over a rolling 12-month forward period and assumes that the contract positions are held through expiration. This calculation is based on a 99% confidence level, which means that there is a 1% probability that the impact to revenues on a pre-tax basis, over the rolling 12-month forward period, will be at least as large as the reported value-at-risk. Value-at-risk uses market data to quantify the Utility's price exposure. When market data is not available, the Utility uses historical data or market proxies to extrapolate the required market data. Value-at-risk as a measure of portfolio risk has several limitations, including, but not limited to, inadequate indication of the exposure to extreme price movements and the use of historical data or market proxies may not adequately capture portfolio risk.

The Utility's value-at-risk calculated under the methodology described above was approximately $26 million and $31 million at December 31, 2006 and December 31, 2005, respectively. The Utility's high, low and average value-at-risk during the year ended December 31, 2006 and December 31, 2005 were approximately $41 million, $22 million and $33 million, and $43 million, $31 million and $36 million, respectively.

Convertible Subordinated Notes

At December 31, 2006, PG&E Corporation had outstanding $280 million of Convertible Subordinated Notes that mature on June 30, 2010. These Convertible Subordinated Notes may be converted (at the option of the holder) at any time prior to maturity into 18,558,655 shares of common stock of PG&E Corporation, at a conversion price of approximately $15.09 per share. The conversion price is subject to adjustment should a significant change occur in the number of PG&E Corporation's outstanding common shares. In addition, holders of the Convertible Subordinated Notes are entitled to receive "pass-through dividends" determined by multiplying the cash dividend paid by PG&E Corporation per share of common stock by a number equal to the principal amount of the Convertible Subordinated Notes divided by the conversion price. In connection with common stock dividends paid to holders of PG&E Corporation common stock, PG&E Corporation paid approximately $24 million of "pass-through dividends" to the holders of Convertible Subordinated Notes in 2006. The holders have a one-time right to require PG&E Corporation to repurchase the Convertible Subordinated Notes on June 30, 2007, at a purchase price equal to the principal amount plus accrued and unpaid interest (including liquidated damages and unpaid "pass-through dividends," if any).

In accordance with SFAS No. 133, the dividend participation rights component of the Convertible Subordinated Notes is considered to be an embedded derivative instrument and, therefore, must be bifurcated from the Convertible Subordinated Notes and recorded at fair value in PG&E Corporation's Consolidated Financial Statements. Changes in the fair value are recognized in PG&E Corporation's Consolidated Statements of Income as a non-operating expense or income (included in Other income (expense), net). At December 31, 2006 and December 31, 2005, the total estimated fair value of the dividend participation rights component, on a pre-tax basis, was approximately $79 million and $92 million, respectively, of which $23 million and $22 million, respectively, was classified as a current liability (in Current Liabilities – Other) and $56 million and $70 million, respectively, was classified as a noncurrent liability (in Noncurrent Liabilities – Other).

INTEREST RATE RISK

Interest rate risk is the risk that changes in interest rates could adversely affect earnings or cash flows. Specific interest rate risks for PG&E Corporation and the Utility include the risk of increasing interest rates on variable rate obligations.

Interest rate risk sensitivity analysis is used to measure interest rate risk by computing estimated changes in cash flows as a result of assumed changes in market interest rates. At December 31, 2006, if interest rates changed by 1% for all current variable rate debt issued by PG&E Corporation and the Utility, the change would affect net income by less than $6 million, based on net variable rate debt and other interest rate-sensitive instruments outstanding.

CRITICAL ACCOUNTING POLICIES

The preparation of Consolidated Financial Statements in accordance with the accounting principles generally accepted in the United States of America involves the use of estimates and assumptions that affect the recorded amounts of assets and liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The accounting policies described below are considered to be critical accounting policies, due, in part, to their complexity and because their application is relevant and material to the financial position and results of operations of PG&E Corporation and the Utility, and because these policies require the use of material judgments and estimates. Actual results may differ substantially from these estimates. These policies and their key characteristics are outlined below.

REGULATORY ASSETS AND LIABILITIES

PG&E Corporation and the Utility account for the financial effects of regulation in accordance with SFAS No. 71. SFAS No. 71 applies to regulated entities whose rates are designed to recover the cost of providing service. SFAS No. 71 applies to all of the Utility's operations.

Under SFAS No. 71, incurred costs that would otherwise be charged to expense may be capitalized and recorded as regulatory assets if it is probable that the incurred costs will be recovered in future rates. The regulatory assets are amortized over future periods consistent with the inclusion of costs in authorized customer rates. If costs that a regulated enterprise expects to incur in the future are being recovered through current rates, SFAS No. 71 requires that the regulated enterprise record those expected future costs as regulatory liabilities. Regulatory assets and liabilities are recorded when it is probable, as defined in SFAS No. 5, "Accounting for Contingencies," or SFAS No. 5, that these items will be recovered or reflected in future rates. Determining probability requires significant judgment on the part of management and includes, but is not limited to, consideration of testimony presented in regulatory hearings, CPUC and FERC ALJ proposed decisions, final regulatory orders and the strength or status of applications for regulatory rehearings or state court appeals. The Utility also maintains regulatory balancing accounts, which are comprised of sales and cost balancing accounts. These balancing accounts are used to record the differences between revenues and costs that can be recovered through rates.

If the Utility determined that it could not apply SFAS No. 71 to its operations or, if under SFAS No. 71, it could not conclude that it is probable that revenues or costs would be recovered or reflected in future rates, the revenues or costs would be charged to income in the period in which they were incurred. If it is determined that a regulatory asset is no longer probable of recovery in rates, then SFAS No. 71 requires that it be written off at that time. At December 31, 2006, PG&E Corporation and the Utility reported regulatory assets (including current regulatory balancing accounts receivable) of approximately $5.5 billion and regulatory liabilities (including current balancing accounts payable) of approximately $4.4 billion.

UNBILLED REVENUES

The Utility records revenue as electricity and natural gas are delivered. Amounts delivered to customers are determined through the systematic readings of customer meters performed on a monthly basis. At the end of each month, the electric and gas usage from the last meter reading is estimated and corresponding unbilled revenue is recorded. The estimate of unbilled revenue is determined by factoring an estimate of the electricity and natural gas load delivered with recent historical usage and rate patterns.

In the following month, the estimate for unbilled revenue is reversed and actual revenue is recorded based on meter readings. The accuracy of the unbilled revenue estimate is affected by factors that include fluctuations in energy demands, weather and changes in the composition of customer classes. At December 31, 2006, accrued unbilled revenues totaled $729 million.

ENVIRONMENTAL REMEDIATION LIABILITIES

Given the complexities of the legal and regulatory environment regarding environmental laws, the process of estimating environmental remediation liabilities is a subjective one. The Utility records a liability associated with environmental remediation activities when it is determined that remediation is probable, as defined in SFAS No. 5, and the cost can be estimated in a reasonable manner. The liability can be based on many factors, including site investigations, remediation, operations, maintenance, monitoring and closure. This liability is recorded at the lower range of estimated costs, unless a more objective estimate can be achieved. The recorded liability is re-examined every quarter.

At December 31, 2006, the Utility's accrual for undiscounted environmental liabilities was approximately $511 million. The Utility's undiscounted future costs could increase to as much as $782 million if other potentially responsible parties are not able to contribute to the settlement of these costs or the extent of contamination or necessary remediation is greater than anticipated.

The accrual for undiscounted environmental liabilities is representative of future events that are likely to occur. In determining maximum undiscounted future costs, events that are possible but not likely are included in the estimation.

ASSET RETIREMENT OBLIGATIONS

The Utility accounts for its long-lived assets under SFAS No. 143, "Accounting for Asset Retirement Obligations," or SFAS No. 143, and Financial Accounting Standards Board, or FASB, Interpretation Number 47, "Accounting for Conditional Asset Retirement Obligations – An Interpretation of SFAS No. 143," or FIN 47. SFAS No. 143 and FIN 47 require that an asset retirement obligation be recorded at fair value in the period in which it is incurred if a reasonable estimate of fair value can be made. In the same period, the associated asset retirement costs are capitalized as part of the carrying amount of the related long-lived asset. Rate-regulated entities may recognize regulatory assets or liabilities as a result of timing differences between the recognition of costs as recorded in accordance with SFAS No. 143 and FIN 47 and costs recovered through the ratemaking process.

The fair value of asset retirement obligations are dependent upon the following components:

- **Decommissioning costs** — The estimated costs for labor, equipment, material and other disposal costs;
- **Inflation adjustment** — The estimated cash flows are adjusted for inflation estimates;
- **Discount rate** — The fair value of the obligation is based on a credit-adjusted risk free rate that reflects the risk associated with the obligation; and
- **Third-party markup adjustments** — Internal labor costs included in the cash flow calculation were adjusted for costs that a third-party would incur in performing the tasks necessary to retire the asset in accordance with SFAS 143.

Changes in these factors could materially affect the obligation recorded to reflect the ultimate cost associated with retiring the assets under SFAS No. 143 and FIN 47. For example, if the inflation adjustment increased 25 basis points, this would increase the balance for asset retirement obligations by approximately 9%. Similarly, an increase in the discount rate by 25 basis points would decrease asset retirement obligations by 3%. At December 31, 2006, the Utility's estimated cost of retiring these assets is approximately $1.5 billion.

ACCOUNTING FOR INCOME TAXES

PG&E Corporation and the Utility account for income taxes in accordance with SFAS No. 109, "Accounting for Income Taxes," which requires judgment regarding the potential tax effects of various transactions and ongoing operations to determine obligations owed to tax authorities. Amounts of deferred income tax assets and liabilities, as well as current and noncurrent accruals, involve estimates of the timing and probability of recognition of income and deductions. Actual income taxes could vary from estimated amounts due to the future impacts of various items including changes in tax laws, PG&E Corporation's financial condition in future periods, and the final review of filed tax returns by taxing authorities.

PENSION AND OTHER POSTRETIREMENT PLANS

Certain employees and retirees of PG&E Corporation and its subsidiaries participate in qualified and non-qualified non-contributory defined benefit pension plans. Certain retired employees and their eligible dependents of PG&E Corporation and its subsidiaries also participate in contributory medical plans, and certain retired employees participate in life insurance plans (referred to collectively as "other postretirement benefits"). Amounts that PG&E Corporation and the Utility recognize as costs and obligations to provide pension benefits under SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans," or SFAS No. 158, SFAS No. 87, "Employers' Accounting for Pensions," or SFAS No. 87, and other benefits under SFAS No. 106, "Employers' Accounting for Postretirement Benefits other than Pensions," or SFAS No. 106, are based on a variety of factors. These factors include the provisions of the plans, employee demographics and various actuarial calculations, assumptions and accounting mechanisms. Because of the complexity of these calculations, the long-term nature of these obligations and the importance of the assumptions utilized, PG&E Corporation's and the Utility's estimate of these costs and obligations is a critical accounting estimate.

Actuarial assumptions used in determining pension obligations include the discount rate, the average rate of future compensation increases and the expected return on plan assets. Actuarial assumptions used in determining other postretirement benefit obligations include the discount rate, the expected return on plan assets and the assumed health care cost trend rate. PG&E Corporation and the Utility review these assumptions on an annual basis and adjust them as necessary. While PG&E Corporation and the Utility believe the assumptions used are appropriate, significant differences in actual experience, plan changes or significant changes in assumptions may materially affect the recorded pension and other postretirement benefit obligations and future plan expenses.

In accordance with accounting rules, changes in benefit obligations associated with these assumptions may not be recognized as costs on the income statement. Differences between actuarial assumptions and actual plan results are deferred in accumulated other comprehensive income and are amortized into cost only when the accumulated differences exceed 10% of the greater of the projected benefit obligation or the market-value of the related plan assets. If necessary, the excess is amortized over the average remaining service period of active employees. As such, significant portions of benefit costs recorded in any period may not reflect the actual level of cash benefits provided to plan participants. PG&E Corporation's and the Utility's recorded pension expense totaled $185 million in 2006, $176 million in 2005 and $182 million in 2004 in accordance with the provisions of SFAS No. 87. PG&E Corporation's and the Utility's recorded expense for other postretirement benefits totaled $49 million in 2006, $55 million in 2005 and $78 million in 2004 in accordance with the provisions of SFAS No. 106.

As of December 31, 2006, PG&E Corporation and the Utility adopted SFAS No. 158 which requires the funded status of an entity's plans to be recognized on the balance sheet with an offsetting entry to accumulated other comprehensive income, resulting in no impact to the statement of income. In accordance with the provisions of SFAS No. 158, PG&E Corporation and the Utility recorded a net pension benefit liability equal to the underfunded status of certain pension plans at December 31, 2006 in the amounts of $70 million and $29 million, respectively. In addition, PG&E Corporation and the Utility recorded a net pension benefit asset equal to the overfunded status of certain pension plans in the amount of $34 million at December 31, 2006. PG&E Corporation and the Utility recorded a net benefit liability equal to the underfunded status of the other postretirement benefit plans at December 31, 2006 in the amount of $54 million.

Under SFAS No. 71, regulatory adjustments have been recorded in the Consolidated Statements of Income and Consolidated Balance Sheets of the Utility to reflect the difference between Utility pension expense or income for accounting purposes and Utility pension expense or income for ratemaking, which is based on a funding approach. Since 1993, the CPUC has authorized the Utility to recover the costs associated with its other benefits based on the lesser of the SFAS No. 106 expense or the annual tax-deductible contributions to the appropriate trusts.

PG&E Corporation's and the Utility's funding policy is to contribute tax deductible amounts, consistent with applicable regulatory decisions and federal minimum funding requirements. Based upon current assumptions and available information, PG&E Corporation and the Utility have not identified any minimum funding requirements related to its pension plans.

In July 2006, the CPUC approved the Utility's 2006 Pension Contribution Application to resume rate recovery for the Utility's contributions to the qualified defined benefit pension plan for the years 2006 through 2009, with the goal of a fully funded status by 2010. PG&E Corporation and the Utility made total contributions to the qualified defined benefit pension plan of approximately $295 million in 2006, of which $20 million related to 2005, and expect to make total contributions of approximately $176 million annually for the years 2007, 2008 and 2009. PG&E Corporation and the Utility made total contributions of approximately $25 million in 2006 related to their other postretirement benefit plans. Contribution estimates for the Utility's other postretirement benefit plans after 2006 will be driven by future GRC decisions and in line with the Utility's funding policy.

Pension and other postretirement benefit funds are held in external trusts. Trust assets, including accumulated earnings, must be used exclusively for pension and other postretirement benefit payments. Consistent with the trusts' investment policies, assets are invested in U.S. equities, non-U.S. equities and fixed income securities. Investment securities are exposed to various risks, including interest rate, credit and overall market volatility. As a result of these risks, it is reasonably possible that the market values of investment securities could increase or decrease in the near term. Increases or decreases in market values could materially affect the current value of the trusts and, as a result, the future level of pension and other postretirement benefit expense.

Expected rates of return on plan assets were developed by determining projected stock and bond returns and then applying these returns to the target asset allocations of the employee benefit trusts, resulting in a weighted average rate of return on plan assets. Fixed income returns were projected based on real maturity and credit spreads added to a long-term inflation rate. Equity returns were estimated based on estimates of dividend yield and real earnings growth added to a long-term rate of inflation. For the Utility Retirement Plan, the assumed return of 8.0% compares to a 10-year actual return of 9.0%.

The rate used to discount pension and other postretirement benefit plan liabilities was based on a yield curve developed from market data of over 500 Aa-grade non-callable bonds at December 31, 2006. This yield curve has discount rates that vary based on the duration of the obligations. The estimated future cash flows for the pension and other postretirement obligations were matched to the corresponding rates on the yield curve to derive a weighted average discount rate.

The following reflects the sensitivity of pension costs and projected benefit obligation to changes in certain actuarial assumptions:

(in millions)	Increase (decrease) in Assumption	Increase in 2006 Pension Cost	Increase in Projected Benefit Obligation at December 31, 2006
Discount rate	(0.5)%	$73	$643
Rate of return on plan assets	(0.5)%	40	—
Rate of increase in compensation	0.5%	30	139

The following reflects the sensitivity of other postretirement benefit costs and accumulated benefit obligation to changes in certain actuarial assumptions:

(in millions)	Increase (decrease) in Assumption	Increase in 2006 Other Post-retirement Benefit Cost	Increase in Accumulated Benefit Obligation at December 31, 2006
Health care cost trend rate	0.5%	$5	$36
Discount rate	(0.5)%	5	81

ACCOUNTING PRONOUNCEMENTS ISSUED BUT NOT YET ADOPTED

ACCOUNTING FOR UNCERTAINTY IN INCOME TAXES

In July 2006, the FASB issued FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes," or FIN 48. FIN 48 clarifies the accounting for uncertainty in income taxes. The interpretation prescribes a two-step process in the recognition and measurement of a tax position taken or expected to be taken in a tax return. The first step is to determine if it is more likely than not that a tax position will be sustained upon examination by taxing authorities. If this threshold is met, the second step is to measure the tax position on the balance sheet by using the largest amount of benefit that is greater than 50 percent likely of being realized upon ultimate settlement. FIN 48 also requires additional disclosures. FIN 48 is effective prospectively for fiscal years beginning after December 15, 2006. PG&E Corporation and the Utility are currently evaluating the impact of this new interpretation.

FAIR VALUE MEASUREMENTS

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements," or SFAS No. 157. SFAS No. 157 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. SFAS No. 157 also establishes a framework for measuring fair value and provides for expanded disclosures about fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007. PG&E Corporation and the Utility are currently evaluating the impact of SFAS No. 157.

FAIR VALUE OPTION

In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities," or SFAS No. 159. SFAS No. 159 establishes a fair value option under which entities can elect to report certain financial assets and liabilities at fair value, with changes in fair value recognized in earnings. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. PG&E Corporation and the Utility are currently evaluating the impact of SFAS No. 159.

TAXATION MATTERS

See Note 11 of the Notes to the Consolidated Financial Statements for discussion on taxation matters.

ENVIRONMENTAL MATTERS

The Utility may be required to pay for environmental remediation at sites where it has been, or may be, a potentially responsible party under the Comprehensive Environmental Response Compensation and Liability Act of 1980, as amended, and similar state environmental laws. These sites include former manufactured gas plant sites, power plant sites and sites used by the Utility for the storage, recycling or disposal of potentially hazardous materials. Under federal and California laws, the Utility may be responsible for remediation of hazardous substances even if the Utility did not deposit those substances on the site.

The cost of environmental remediation is difficult to estimate. The Utility records an environmental remediation liability when site assessments indicate remediation is probable and it can estimate a range of reasonably likely clean-up costs. The Utility reviews its remediation liability on a quarterly basis for each site where it may be exposed to remediation responsibilities. The liability is an estimate of costs for site investigations, remediation, operations and maintenance, monitoring and site closure using current technology, enacted laws and regulations, experience gained at similar sites and an assessment of the probable level of involvement and financial condition of other potentially responsible parties. Unless there is a better estimate within this range of possible costs, the Utility records the costs at the lower end of this range. The Utility estimates the upper end of this cost range using reasonably possible outcomes that are least favorable to the Utility. It is reasonably possible that a change in these estimates may occur in the near term due to uncertainty concerning the Utility's responsibility, the complexity of environmental laws and regulations and the selection of compliance alternatives.

The Utility had an undiscounted environmental remediation liability of approximately $511 million at December 31, 2006 and approximately $469 million at December 31, 2005. The increase in the undiscounted environmental remediation reflects an increase of $74 million for remediation at the Utility's gas compressor stations located near Hinkley, California and Topock, Arizona. The portion of the increased liability of $39 million for remediation at the Hinkley facility is attributable to changes in the California Regional Water Quality Control Board's imposed remediation levels. Costs incurred at this facility are not recoverable from customers and, as a result, the after-tax impact on income was a reduction of approximately $23 million for 2006. Ninety percent of the estimated remediation costs associated with the Utility's gas compressor station located near Topock, Arizona will be recoverable in rates in accordance with the hazardous waste ratemaking mechanism which permits the Utility to recover 90% of hazardous waste remediation costs from customers without a reasonableness review.

The $511 million accrued at December 31, 2006 includes:

- approximately $238 million for remediation at the Hinkley and Topock natural gas compressor sites;
- approximately $98 million related to the pre-closing remediation liability associated with divested generation facilities; and
- approximately $175 million related to remediation costs for the Utility's generation facilities and gas gathering sites, third-party disposal sites and manufactured gas plant sites owned by the Utility or third parties (including those sites that are the subject of remediation orders by environmental agencies or claims by the current owners of the former manufactured gas plant sites).

Of the approximately $511 million environmental remediation liability, approximately $138 million has been included in prior rate setting proceedings. The Utility expects that an additional amount of approximately $272 million will be allowable for inclusion in future rates. The Utility also recovers its costs from insurance carriers and from other third parties whenever possible. Any amounts collected in excess of the Utility's ultimate obligations may be subject to refund to customers.

The Utility's undiscounted future costs could increase to as much as $782 million if the other potentially responsible parties are not financially able to contribute to these costs, or if the extent of contamination or necessary remediation is greater than anticipated. The amount of approximately $782 million does not include an estimate for any potential costs of remediation at former manufactured gas plant sites in the Utility's service territory that were previously owned by the Utility or a predecessor but that are now owned by others because the Utility either has not been able to determine if a liability exists with respect to these sites or the Utility has not been able to estimate the amount of any future potential remediation costs that may be incurred for these sites.

In July 2004, the U.S. Environmental Protection Agency, or EPA, published regulations under Section 316(b) of the Clean Water Act for cooling water intake structures. The regulations affect existing electricity generation facilities using over 50 million gallons per day, typically including some form of "once-through" cooling. The Utility's Diablo Canyon power plant is among an estimated 539 generation facilities nationwide that are affected by this rulemaking. The Utility permanently closed its Hunters Point power plant in May 2006, and the Humboldt Bay power plant will be re-powered without the use of once-through cooling. The EPA regulations establish a set of performance standards that vary with the type of water body and that are intended to reduce impacts to aquatic organisms. Significant capital investment may be required to achieve the standards. The regulations allow site-specific compliance determinations if a facility's cost of compliance is significantly greater than either the benefits achieved or the compliance costs considered by the EPA and also allow the use of environmental mitigation or restoration to meet compliance requirements in certain cases. Various parties challenged the EPA's regulations and the cases were consolidated in the U.S. Court of Appeals for the Second Circuit, or Second Circuit.

On January 25, 2007, the Second Circuit issued its decision on the appeals of the EPA Section 316(b) regulations. The Second Circuit remanded significant provisions of the regulations to the EPA for reconsideration and held that a cost benefit test cannot be used to establish performance standards or to grant variances from the standards. The Second Circuit also ruled that environmental restoration cannot be used to achieve compliance. The parties may seek either en banc review by the Second Circuit or review by the U.S. Supreme Court. Regardless of whether the decision is subject to further judicial review, the EPA will likely require significant time to review and revise the regulations. It is uncertain how the Second Circuit decision will affect development of the state's proposed implementation policy. The regulatory uncertainty is likely to continue and the Utility's cost of compliance, while likely to be significant, will remain uncertain as well.

LEGAL MATTERS

In the normal course of business, PG&E Corporation and the Utility are named as parties in a number of claims and lawsuits. See Note 17 of the Notes to the Consolidated Financial Statements for further discussion.

ADDITIONAL SECURITY MEASURES

Various federal regulatory agencies have issued guidance and the NRC has issued orders regarding additional security measures to be taken at various facilities, including generation facilities, transmission substations and natural gas transportation facilities. The guidance and the orders require additional capital investment and increased operating costs. However, neither PG&E Corporation nor the Utility believes that these costs will have a material impact on its respective consolidated financial position or results of operations.

RISK FACTORS

RISKS RELATED TO PG&E CORPORATION

PG&E Corporation could be required to contribute capital to the Utility or be denied distributions from the Utility to the extent required by the CPUC's determination of the Utility's financial condition.

In approving the original formation of a holding company for the Utility, the CPUC imposed certain conditions, including an obligation by PG&E Corporation's Board of Directors to give "first priority" to the capital requirements of the Utility, as determined to be necessary and prudent to meet the Utility's obligation to serve or to operate the Utility in a prudent and efficient manner. The CPUC later issued decisions in which it adopted an expansive interpretation of PG&E Corporation's obligations under this condition, including the requirement that PG&E Corporation "infuse the [U]tility with all types of capital necessary for the [U]tility to fulfill its obligation to serve." The CPUC's expansive interpretation could require PG&E Corporation to infuse the Utility with significant capital in the future, or be denied distributions from the Utility, which could materially restrict PG&E Corporation's ability to meet other obligations.

Adverse resolution of pending litigation could have a material adverse effect on PG&E Corporation's financial condition and results of operations.

In 2002, the California Attorney General and the City and County of San Francisco filed complaints against PG&E Corporation alleging that certain conditions imposed by the CPUC in approving the holding company formation, including the so-called "first priority condition," were violated and that these alleged violations constituted unfair or fraudulent business acts or practices in violation of Section 17200 of the California Business and Professions Code. They allege that transfers of funds from the Utility to PG&E Corporation during the period 1997 through 2000 (primarily in the form of dividends and stock repurchases), and from PG&E Corporation to other affiliates of PG&E Corporation, violated these holding company conditions. They also allege that PG&E Corporation wrongfully failed to provide adequate financial support to the Utility in 2000 and 2001 during the California energy crisis. The plaintiffs seek restitution of amounts alleged to have been wrongly transferred estimated by plaintiffs to be approximately $5 billion, civil penalties of $2,500 against each defendant for each violation of Section 17200, a total penalty of not less than $500 million, and costs of suit, among other remedies.

An adverse outcome, particularly one imposing significant penalties, could have a material adverse affect on PG&E Corporation's financial condition, results of operations and cash flows.

RISKS RELATED TO THE UTILITY

PG&E Corporation's and the Utility's financial condition depends upon the Utility's ability to recover its costs in a timely manner from the Utility's customers through regulated rates and otherwise execute its business strategy.

The Utility is a regulated entity subject to CPUC and FERC jurisdiction in almost all aspects of its business, including the rates, terms and conditions of its services, procurement of electricity and natural gas for its customers, issuance of securities, dispositions of utility assets and facilities and aspects of the siting and operation of its electricity and natural gas operating assets. Executing the Utility's business strategy depends on periodic regulatory approvals related to these and other matters.

The Utility's financial condition particularly depends on its ability to recover in rates in a timely manner the costs of electricity and natural gas purchased for its customers, as well as an adequate return on the capital invested in its utility assets, including the long-term debt and equity issued to finance their acquisition. There may be unanticipated changes in operating expenses or capital expenditures that cause material differences between forecasted costs used to determine rates and actual costs incurred which, in turn, affect the Utility's ability to earn its authorized rate of return. The CPUC also has approved various programs to support public policy goals through the use of customer incentives and subsidies for energy efficiency programs and the development and use of renewable and self-generation technologies. These and other similar incentives and subsidies increase the Utility's overall costs. As rate pressure increases, the risk increases that the CPUC or other state authority will disallow recovery of some of the Utility's costs based on a determination that the costs were not reasonably incurred or for some other reason, resulting in stranded investment capital.

Further, changes in laws and regulations or changes in the political and regulatory environment may have an adverse effect on the Utility's ability to timely recover its costs and earn its authorized rate of return. During the 2000–2001 energy crisis that followed the implementation of California's electric industry restructuring law, the Utility could not recover in rates the high prices it had to pay for wholesale electricity, which ultimately caused the Utility to file a petition for reorganization under Chapter 11 of the U.S. Bankruptcy Code. Even though the Chapter 11 Settlement Agreement and current regulatory mechanisms contemplate that the CPUC will give the Utility the opportunity to recover its reasonable and prudent future costs of electricity and natural gas in its rates, there can be no assurance that the CPUC will find that all of the Utility's costs are reasonable and prudent or will not otherwise take or fail to take actions to the Utility's detriment.

In addition, there can be no assurance that the bankruptcy court or other courts will implement and enforce the terms of the Chapter 11 Settlement Agreement and the Utility's plan of reorganization in a manner that would produce the economic results that PG&E Corporation and the Utility intend or anticipate. Further, there can be no assurance that FERC-authorized tariffs will be adequate to cover the related costs. The Utility's failure to recover any material amount of its costs through its rates in a timely manner, would have a material adverse effect on PG&E Corporation's and the Utility's financial condition, results of operations and cash flows.

The Utility faces significant uncertainty in connection with the implementation of the CAISO's Market Redesign and Technology Upgrade program to restructure California's wholesale electricity market. In addition, the Utility must comply with new reliability standards being promulgated under the Energy Policy Act of 2005.

In response to the market manipulation that occurred during the 2000–2001 energy crisis, the CAISO has undertaken a Market Redesign and Technology Upgrade, or MRTU, initiative to implement a new day-ahead wholesale electricity market, and improve electricity grid management reliability, operational efficiencies and related technology infrastructure. MRTU, scheduled to become effective in January 2008, will add significant market complexity and will require major changes to the Utility's systems and software interfacing with the CAISO. Also, as part of the implementation of the Energy Policy Act of 2005, new mandatory standards are being developed relating to the operation and maintenance of the electric grid. The new standards are subject to the FERC's approval and new enforcement authority. The FERC can impose significant penalties ($1,000,000 per day per violation) for failure to comply with the reliability standards. If the Utility incurs significant costs to implement MRTU that are not timely recovered from customers, or if the new market mechanisms created by MRTU fail to react promptly to price/market flaws or if the needed systems and software interfaces do not perform as intended, or if the Utility fails to comply with the new electric reliability standards, PG&E Corporation's and the Utility's financial condition, results of operations and cash flows could be materially adversely affected.

The Utility may be unable to achieve expected cost savings and efficiencies from its customer service improvement initiatives.

During 2006 the Utility began to implement various initiatives to change its business processes and systems so as to achieve operational excellence and to provide better, faster and more cost-effective service to its customers. Many of these initiatives require substantial costs to implement with savings expected to be realized in later years. The proposed settlement of the Utility's 2007 GRC contemplates that customers would receive the benefit of cost savings attributable to implementation of these initiatives in 2008, 2009 and 2010. If the actual cost savings exceed the contemplated savings, such benefits would accrue to shareholders. Conversely, if any of these cost savings are not realized, earnings available for shareholders would be reduced.

There can be no assurance that the Utility will be able to recognize cost savings through implementation of these initiatives and its failure to do so could have a material adverse effect on PG&E Corporation's and the Utility's financial condition, results of operations and cash flows.

The Utility may fail to recognize the benefits of its advanced metering system or the advanced metering system may fail to perform as intended, resulting in higher costs and/or reduced cost savings.

During 2006 the Utility began to implement its advanced metering infrastructure project for residential and small commercial customers, involving the installation of approximately 10 million advanced electricity and gas meters throughout its service territory, by the end of 2011. Advanced meters will allow customer usage data to be transmitted through a communication network to a central collection point, where the data will be stored and used for billing and other commercial purposes. The Utility expects to complete the installation of the network infrastructure and advanced meters throughout its service territory by the end of 2011.

The CPUC authorized the Utility to recover $1.74 billion in estimated project cost, including an estimated capital cost of $1.4 billion. The $1.74 billion amount includes $1.68 billion for project costs and approximately $54.8 million for costs related to marketing a new demand responsive rate based on critical peak pricing. In addition, the Utility is authorized to recover in rates 90% of up to $100 million in costs that exceed $1.68 billion without a reasonableness review. The remaining 10% will not be recoverable in rates. If additional costs exceed the $100 million threshold, the Utility may request recovery of the additional costs, subject to a reasonableness review. The Utility estimates that approximately 90% of the project costs will be recovered through cost reduction benefits.

If the Utility fails to recognize the expected benefits of its advanced metering infrastructure, if the Utility incurs additional costs that the CPUC does not find reasonable, or if the Utility is unable to integrate the new advanced metering system with its billing and other computer information systems, PG&E Corporation's and the Utility's financial condition, results of operations and cash flows could be materially adversely affected.

The Utility faces significant uncertainties associated with the future level of bundled electric load for which it must procure electricity and secure generating capacity and, under certain circumstances, may not be able to recover all of its costs.

The Utility is responsible to procure electricity to meet customer demand, plus applicable reserve margins, not satisfied from the Utility's own generation facilities and existing electricity contracts. The Utility relies on electricity from a diverse mix of resources, including third-party contracts, amounts allocated under DWR contracts and its own electricity generation facilities. When customer demand exceeds the amount of electricity that can be economically produced from the Utility's own generation facilities plus net energy purchase contracts (including DWR contracts allocated to the Utility's customers), the Utility will be in a "short" position. When the Utility's supply of electricity from its own generation resources plus net energy purchase contracts exceeds customer demand, the Utility is in a "long" position. When the Utility is in a long position, the Utility sells the excess supply in the hour- and day-ahead markets or in the forward markets.

The amount of electricity the Utility needs to meet the demands of customers that is not satisfied from the Utility's own generation facilities, existing purchase contracts or DWR contracts allocated to the Utility's customers, could increase or decrease due to a variety of factors, including, without limitation, a change in the number of the Utility's customers, periodic expirations of existing electricity purchase contracts, including DWR contracts, execution of new energy and capacity purchase contracts, fluctuation in the output of hydroelectric and other renewable power facilities owned or under contract by the Utility, implementation of new energy efficiency and demand response programs, the reallocation of the DWR power purchase contracts among California investor-owned electric utilities, and the acquisition, retirement, or closure of generation facilities. The amount of electricity the Utility would need to purchase would immediately increase if there was an unexpected outage at Diablo Canyon or any of its other significant generation facilities, if the Utility had to shut down Diablo Canyon for any reason, or if any of the counterparties to the Utility's electricity purchase contracts or the DWR allocated contracts did not perform due to bankruptcy or for some other reason. In addition, as the electricity supplier of last resort, the amount of electricity the Utility would need to purchase also would immediately increase if a material number of direct access customers or customers of community choice aggregators decided to return to receiving bundled services from the Utility. (See discussion of direct access and community choice aggregators above under "Regulatory Matters – Electricity Generation Resources.")

If the Utility's short position unexpectedly increases, the Utility would need to purchase electricity in the wholesale market under contracts priced at the time of execution or, if made in the spot market, at the then-current market price of wholesale electricity. The inability of the Utility to purchase electricity in the wholesale market at prices or on terms the CPUC finds reasonable or in quantities sufficient to satisfy the Utility's short position could have a material adverse effect on the financial condition, results of operations or cash flows of the Utility and PG&E Corporation.

Alternatively, the Utility would be in a long position if the number of Utility customers declined. For example, a petition was filed in late December 2006 asking the CPUC to examine re-establishing the ability of the Utility's customers to become direct access customers by purchasing electricity from alternate energy providers by January 1, 2008. Separately, the CPUC has adopted rules to implement California Assembly Bill 117 that permits California cities and counties to purchase and sell electricity for all their residents who do not affirmatively elect to continue to receive electricity from the Utility, once the city or county has registered as a community choice aggregator, while the Utility continues to provide distribution, metering and billing services to the community choice aggregators' customers and serves as the electricity provider of last resort for all customers. In addition, the Utility could lose customers because of increased self-generation. The risk of loss of customers through self-generation is increasing as the CPUC has approved various programs to provide self-generation incentives and subsidies to customers to encourage development and use of renewable and distributed generating technologies, such as solar technology. The number of the Utility's customers also could decline due to a general economic downturn or if higher energy prices in California due to stricter greenhouse gas regulations or other state regulations cause customers to leave the Utility's service territory.

If the Utility experiences a material loss of customers, the Utility's existing electricity purchase contracts could obligate it to purchase more electricity than its remaining customers require. This would result in a long position and require the Utility to sell the excess, possibly at a loss. In addition, excess electricity generated by the Utility's generation facilities may also have to be sold, possibly at a loss, and costs the Utility may have incurred to develop or acquire new generation resources may become stranded.

If the CPUC fails to adjust the Utility's rates to reflect the impact of changing loads, PG&E Corporation's and the Utility's financial condition, results of operations and cash flows could be materially adversely affected.

The Utility relies on access to the capital markets. There can be no assurance that the Utility will be able to successfully finance its planned capital expenditures on favorable terms or rates.

The Utility's ability to make scheduled principal and interest payments, refinance debt and fund operations and planned capital expenditures depends on its operating cash flow and access to the capital markets. During 2006, the CPUC authorized the Utility to make substantial capital investments in new long-term generation resources. The Utility also expects to make capital investments in electric transmission to secure access to renewable generation resources and to accommodate system load growth, in natural gas transmission to improve reliability and expand capacity and to replace aging or obsolete infrastructure (e.g., pipelines, storage facilities and compressor stations) to maintain system reliability, and in the electric and gas distribution system. In addition, the Utility expends capital to replace, refurbish or extend the life of its existing nuclear, hydroelectric and fossil facilities. The Utility's ability to access the capital markets and the costs and terms of available financing depend on many factors, including changes in the Utility's credit ratings, changes in the federal or state regulatory environment affecting energy companies, increased or natural volatility in electricity or natural gas prices and general economic and market conditions.

PG&E Corporation's and the Utility's financial condition and results of operations would be materially adversely affected if the Utility is unable to obtain financing with favorable terms and conditions, or at all.

The completion of the Utility's capital investment projects is subject to substantial risks and the rate at which the Utility invests capital will directly affect earnings.

The completion of the Utility's anticipated capital investment projects in existing and new generation facilities, electric and gas transmission, and electric and gas distribution systems is subject to many construction and development risks, including risks related to financing, obtaining and complying with the terms of permits, meeting construction budgets and schedules, and satisfying operating and environmental performance standards. The Utility also faces the risk that it may incur costs that it will not be permitted to recover from customers. In addition, the timing and amount of capital spending will directly affect the amount the Utility is able to earn on its authorized rate base, which in turn will affect the ability of PG&E Corporation and the Utility to grow its earnings over time.

If the Utility is unable to timely meet the applicable resource adequacy or renewable energy requirements, the Utility may be subject to penalties.

The Utility must achieve an electricity planning reserve margin of 15% to 17% in excess of peak capacity electricity requirements. The CPUC can impose a penalty if it fails to acquire sufficient capacity to meet resource adequacy requirements for a particular year. The penalty for failure to procure sufficient system resource adequacy capacity (i.e., resources that are deliverable anywhere in the CAISO-controlled electricity grid) is equal to three times the cost of the new capacity the Utility should have secured. The CPUC has set this penalty at $120 per kW-year. The CPUC also adopted "local" resource adequacy requirements to set local capacity requirements in specific regions that may be transmission-constrained. The CPUC set the penalty for failure to meet local resource adequacy requirements at $40 per kW-year. In addition to penalties, entities that fail to meet resource adequacy requirements may be assessed the cost of backstop procurement by the CAISO to fulfill their resource adequacy target levels.

In addition, the RPS established under state law requires the Utility to increase its purchases of renewable energy each year so that the amount of electricity purchased from eligible renewable resources equals at least 20% of its total retail sales by the end of 2010. The CPUC has established penalties of $50 per MWh, up to $25 million per year, for failure to comply with the RPS requirements.

The Utility faces the risk of unrecoverable costs if its customers obtain distribution and transportation services from other providers as a result of municipalization, technological change, or other forms of bypass.

The Utility's customers could bypass its distribution and transportation system by obtaining service from other sources. Forms of bypass of the Utility's electricity distribution system include construction of duplicate distribution facilities to serve specific existing or new customers and condemnation of the Utility's distribution facilities by local governments or municipal districts. The Utility's natural gas transportation facilities could also be at risk of being bypassed by interstate pipeline companies that construct facilities in the Utility's markets or by customers who build pipeline connections that bypass the Utility's natural gas transportation and distribution system, or by customers who use and transport liquefied natural gas, or LNG.

As customers and local public officials continue to explore their energy options, these bypass risks may be increasing and may increase further if the Utility's rates exceed the cost of other available alternatives, resulting in stranded investment capital, loss of customer growth and additional barriers to cost recovery. As examples, the Sacramento Municipal Utility District, or SMUD, sought to proceed with plans to exercise its power of eminent domain to acquire portions of the Utility's electric system within Yolo County which serves approximately 70,000 Utility customers and the South San Joaquin Irrigation District, or SSJID, has sought approval from the local agency formation commission to serve portions of the Utility's electric system within San Joaquin County. Although SMUD's plans were ultimately defeated by voters in Yolo and Sacramento Counties on November 7, 2006 and SSJID's plans have been rejected by the local agency formation commission, there is no assurance that SSJID may not continue to pursue its efforts, or that others may not choose to follow a similar path.

If the number of the Utility's customers declines due to municipalization, or other forms of bypass, and the Utility's rates are not adjusted in a timely manner to allow it to fully recover its investment in electricity and natural gas facilities and electricity procurement costs, PG&E Corporation's and the Utility's financial condition, results of operations and cash flows could be materially adversely affected.

Electricity and natural gas markets are highly volatile and regulatory responsiveness to that volatility could be insufficient.

Commodity markets for electricity and natural gas are highly volatile and subject to substantial price fluctuations. A variety of factors that are largely outside of the Utility's control may contribute to commodity price volatility, including:

- weather;
- supply and demand;
- the availability of competitively priced alternative energy sources;
- the level of production of natural gas;
- the availability of nuclear fuel;
- the availability of LNG supplies;
- the price of fuels that are used to produce electricity, including natural gas, crude oil, coal and nuclear materials;
- the transparency, efficiency, integrity and liquidity of regional energy markets affecting California;
- electricity transmission or natural gas transportation capacity constraints;
- federal, state and local energy and environmental regulation and legislation; and
- natural disasters, war, terrorism, and other catastrophic events.

Beginning in July 2006, the fixed price provisions of the Utility's power purchase agreements with QFs expired and QFs became able to pass on their cost of the natural gas they purchase as fuel for their generating facilities to the Utility, increasing the Utility's exposure to natural gas price volatility. The expiration of fixed price provisions in the DWR contracts allocated to the Utility at the end of 2009 will further increase the Utility's exposure to natural gas price risk. Although the Utility attempts to execute CPUC-approved hedging programs to reduce the natural gas price risk, there can be no assurance that these hedging programs will be successful or that the costs of the Utility's hedging programs will be fully recoverable.

Further, if wholesale electricity or natural gas prices increase significantly, public pressure or other regulatory or governmental influences or other factors could constrain the willingness or ability of the CPUC to authorize timely recovery of the Utility's costs from customers. If the Utility is unable to recover any material amount of its costs in its rates in a timely manner, PG&E Corporation's and the Utility's financial condition, results of operations and cash flows would be materially adversely affected.

The Utility's financial condition and results of operations could be materially adversely affected if it is unable to successfully manage the risks inherent in operating the Utility's facilities.

The Utility owns and operates extensive electricity and natural gas facilities that are interconnected to the U.S. western electricity grid and numerous interstate and continental natural gas pipelines. The operation of the Utility's facilities and the facilities of third parties on which it relies involves numerous risks, including:

- operating limitations that may be imposed by environmental laws or regulations, including those relating to greenhouse gases, or other regulatory requirements;
- imposition of operational performance standards by agencies with regulatory oversight of the Utility's facilities;
- environmental accidents, including the release of hazardous or toxic substances into the air or water, urban wildfires and other events caused by operation of the Utility's facilities or equipment failure;
- fuel supply interruptions;
- blackouts;
- failure of the Utility's computer information systems, including those relating to operations or financial information such as customer billing;
- labor disputes, workforce shortage, availability of qualified personnel;

- weather, storms, earthquakes, fires, floods or other natural disasters, war, pandemic and other catastrophic events;
- explosions, accidents, dam failure, mechanical breakdowns, terrorist activities; and
- other events or hazards

that affect demand for electricity or natural gas, result in unplanned outages, reduce generating output, cause damage to the Utility's assets or operations or those of third parties on which it relies, or subject the Utility to third-party claims or liability for damage or injury.

In addition, substantial uncertainty exists relating to the potential impacts of climate change on the Utility's electricity and natural gas operations as a result of increased frequency and severity of hot weather, decreased hydroelectric generation resulting from reduced runoff from snow pack and increased sea level along the Northern California coastal area. Climate change is likely to affect the operation of the Utility's hydroelectric system and to lead to more severe weather events which will increase the need for additional generation capacity without commensurate increases in average load.

The impact of these events could range from highly localized to worldwide, and in certain events could result in a full or partial disruption of the ability of the Utility or one or more entities on which it relies to generate, transmit, transport or distribute electricity or natural gas or cause environmental repercussions. Even the less extreme events could result in lower revenues or increased expenses, or both, that may not be fully recovered through rates or other means in a timely manner or at all. In addition, the Utility's insurance may not be sufficient or effective to provide recovery under all circumstances or against all hazards or liabilities to which the Utility is or may become subject. An uninsured loss could have a material adverse effect on PG&E Corporation's and the Utility's financial condition, results of operations and cash flows. Future insurance coverage may not be available at rates and on terms as favorable as the rates and terms of the Utility's current insurance coverage.

The Utility's operations are subject to extensive environmental laws, and changes in, or liabilities under, these laws could adversely affect its financial condition and results of operations.

The Utility's operations are subject to extensive federal, state and local environmental laws and permits. Complying with these environmental laws has in the past required significant expenditures for environmental compliance, monitoring and pollution control equipment, as well as for related fees and permits. Moreover, compliance in the future may require significant expenditures relating to reduction of greenhouse gases, regulation of water intake or discharge at certain facilities and mitigation measures associated with electric and magnetic fields. New California legislation imposes a state-wide limit on the emission of greenhouse gases that must be achieved by 2020 and prohibits load-serving entities, including investor-owned utilities, from entering into long-term financial commitments for generation resources unless the new generation resources conform to a greenhouse gas emission performance standard. Congress may also enact legislation to limit greenhouse gas emissions. Depending on how the baseline for greenhouse gas emissions level is set, complying with California regulation and potential federal legislation may subject the Utility to significant costs. The Utility has significant liabilities (currently known, unknown, actual and potential) related to environmental contamination at Utility facilities, including natural gas compressor stations and former manufactured gas plants, as well as at third-party owned sites. The Utility's environmental compliance and remediation costs could increase, and the timing of its capital expenditures in the future may accelerate, if standards become stricter, regulation increases, other potentially responsible parties cannot or do not contribute to cleanup costs, conditions change or additional contamination is discovered.

In the event the Utility must pay materially more than the amount that it currently has reserved on its Consolidated Balance Sheets to satisfy its environmental remediation obligations and cannot recover those or other costs of complying with environmental laws in its rates in a timely manner or at all, PG&E Corporation's and the Utility's financial condition, results of operations and cash flows would be materially adversely affected.

The operation and decommissioning of the Utility's nuclear power plants expose it to potentially significant liabilities and capital expenditures that it may not be able to recover from its insurance or other sources, adversely affecting its financial condition, results of operations and cash flows. The operation and decommissioning of the Utility's nuclear power plants expose it to potentially significant liabilities and capital expenditures, including not only the risk of death, injury and property damage from a nuclear accident, but matters arising from the storage, handling and disposal of radioactive materials including spent nuclear fuel; stringent safety and security requirements; public and political opposition to nuclear power operations; and uncertainties related to the regulatory, technological and financial aspects of decommissioning nuclear plants at the end of their licensed lives. The Utility maintains external insurance coverage and decommissioning trusts to reduce the Utility's financial exposure to these risks. However, the costs or damages the Utility may incur in connection with the operation and decommissioning of nuclear power plants could exceed the amount of the Utility's insurance coverage and other amounts set aside for these potential liabilities. In addition, as an operator of two operating nuclear reactor units, the Utility may be required under federal law to pay up to $201.2 million of liabilities arising out of each nuclear incident occurring not only at Diablo Canyon but at any other nuclear power plant in the United States.

The NRC has broad authority under federal law to impose licensing and safety-related requirements upon owners and operators of nuclear power plants. In the event of non-compliance, the NRC has the authority to impose fines or to force a shutdown of the nuclear plant, or both, depending upon the NRC's assessment of the severity of the situation. NRC safety and security requirements have, in the past, necessitated substantial capital expenditures at Diablo Canyon and additional significant capital expenditures could be required in the future. If one or both units at Diablo Canyon were shut down pursuant to an NRC order or to comply with NRC licensing, safety or security requirements or due to other safety or operational issues, the Utility's operating and maintenance costs would increase. Further, such events may cause the Utility to be in a short position and the Utility would need to purchase electricity from more expensive sources.

In addition, the Utility's nuclear power operations are subject to the availability of adequate nuclear fuel supplies on terms that the CPUC will find reasonable. Although the Utility has entered several purchase agreements for nuclear fuel with terms ranging from two to five years, there is no assurance the Utility will be able to enter into similar agreements in the future with terms that the CPUC will find are reasonable.

Under the terms of the NRC operating licenses for Diablo Canyon, there must be sufficient storage capacity for the radioactive spent fuel produced by this plant. Under current operating procedures, the Utility believes that the existing spent fuel pools have sufficient capacity to enable the Utility to operate Diablo Canyon until approximately 2010 for Unit 1 and 2011 for Unit 2. After receiving a permit from the NRC in March 2004, the Utility began building an on-site dry cask storage facility to store spent fuel through at least 2024. The Utility estimates it could complete the dry cask storage project by 2008. Following an appeal of the NRC's March 2004 decision to grant the permit, the Ninth Circuit issued a decision on June 2, 2006 that requires the NRC to consider the environmental consequences of a potential terrorist attack at Diablo Canyon as part of the NRC's supplemental assessment of the dry cask storage permit. On January 16, 2007, the U.S. Supreme Court denied the Utility's petition for review of the Ninth Circuit decision. The Utility may incur significant additional capital expenditures or experience schedule delays if the NRC decides that the Utility must change the design and construction of the dry cask storage facility. The NRC also may decide to deny the permit. There can be no assurance that the Utility can obtain the final necessary regulatory approvals to expand spent fuel capacity or that other alternatives will be available or implemented in time to avoid a disruption in production or shutdown of one or both units at this plant. If there is a disruption in production or shutdown of one or both units at this plant, the Utility will need to purchase electricity from more expensive sources.

Further, certain aspects of the Utility's nuclear operations are subject to other local and regulatory requirements that are overseen by other agencies, such as the California Coastal Commission and the Central Coast Regional Water Quality Control Board. Various parties, including local community, environmental, political, or other groups may participate, or seek to intervene, in regulatory proceedings. In addition, these groups may seek to challenge certain aspects of the Utility's nuclear operations through judicial proceedings.

If the CPUC prohibited the Utility from recovering a material amount of its capital expenditures, fuel costs, operating and maintenance costs, or additional procurement costs due to a determination that the costs were not reasonably or prudently incurred, PG&E Corporation's and the Utility's financial condition, results of operations and cash flows would be materially adversely affected.

Changes in the political and regulatory environment could cause federal and state statutes, CPUC and FERC regulations, rules and orders to become more stringent and difficult to comply with and required permits, authorizations and licenses may be more difficult to obtain, increasing the Utility's expenses or making it more difficult for the Utility to execute its business strategy.

The Utility must comply in good faith with all applicable statutes, rules, tariffs and orders of the CPUC, the FERC, the NRC and others relating to the aspects of its electricity and natural gas utility operations which fall within the jurisdictional authority of such regulatory agencies. These include customer billing, customer service, affiliate transactions, vegetation management and safety and inspection practices. There is a risk that the interpretation and application of these statutes, rules, tariffs and orders may change over time and that the Utility will be determined to have not complied with the new interpretation. If so, this could expose the Utility to increased costs to comply with the new interpretation and to potential liability for customer refunds, penalties or other amounts. Moreover, such statutes, rules, tariffs and orders could become more stringent and difficult to comply with in the future.

If it is determined that the Utility did not comply with applicable statutes, rules, tariffs, or orders, and the Utility is ordered to pay a material amount in customer refunds, penalties, or other amounts, PG&E Corporation's and the Utility's financial condition, results of operations and cash flows would be materially adversely affected.

The Utility is also required to comply with the terms of various permits, authorizations and licenses. These permits, authorizations and licenses may be revoked or modified by the agencies that granted them if facts develop that differ significantly from the facts assumed when they were issued. In addition, discharge permits and other approvals and licenses are often granted for a term that is less than the expected life of the associated facility. Licenses and permits may require periodic renewal, which may result in additional requirements being imposed by the granting agency. In connection with a license renewal, the FERC may impose new license conditions that could, among other things, require increased expenditures or result in reduced electricity output and/or capacity at the facility.

Also, if the Utility is unable to obtain, renew or comply with these governmental permits, authorizations or licenses, or if the Utility is unable to recover any increased costs of complying with additional license requirements or any other associated costs in its rates in a timely manner, PG&E Corporation's and the Utility's financial condition and results of operations could be materially adversely affected.

The outcome of pending and future litigation and legal proceedings, the application of and changes in accounting standards or guidance, tax laws, rates or policies, also may adversely affect the Utility's financial condition, results of operations or cash flows.

In the normal course of business, the Utility is named as a party in a number of claims and lawsuits. The Utility may also be the subject of investigative or enforcement proceedings conducted by administrative or regulatory agencies. In accordance with applicable accounting standards, the Utility makes provisions for liabilities when it is both probable that a liability has been incurred and the amount of the loss can be reasonably estimated. If the Utility incurs losses in connection with litigation or other legal, administrative or regulatory proceedings that materially exceeded the provision it made for liabilities, PG&E Corporation's and the Utility's financial condition, results of operations and cash flows would be materially adversely affected.

In addition, there is a risk that changes in accounting or tax rules, standards, guidance, policies, or interpretations, or that changes in management's estimates and assumptions underlying reported amounts of revenues, expenses, assets and liabilities, may result in write-offs, impairments or other charges that could have a material adverse affect on PG&E Corporation's and the Utility's financial condition, results of operations and cash flows.

CONSOLIDATED STATEMENTS OF INCOME

PG&E Corporation

	Year ended December 31,		
(in millions, except per share amounts)	2006	2005	2004
Operating Revenues			
Electric	$ 8,752	$ 7,927	$ 7,867
Natural gas	3,787	3,776	3,213
Total operating revenues	12,539	11,703	11,080
Operating Expenses			
Cost of electricity	2,922	2,410	2,770
Cost of natural gas	2,097	2,191	1,724
Operating and maintenance	3,703	3,397	2,871
Recognition of regulatory assets	—	—	(4,900)
Depreciation, amortization, and decommissioning	1,709	1,735	1,497
Total operating expenses	10,431	9,733	3,962
Operating Income	2,108	1,970	7,118
Interest income	188	80	63
Interest expense	(738)	(583)	(797)
Other expense, net	(13)	(19)	(98)
Income Before Income Taxes	1,545	1,448	6,286
Income tax provision	554	544	2,466
Income From Continuing Operations	991	904	3,820
Discontinued Operations			
Gain on disposal of NEGT (net of income tax benefit of $13 million in 2005 and income tax expense of $374 million in 2004)	—	13	684
Net Income	$ 991	$ 917	$ 4,504
Weighted Average Common Shares Outstanding, Basic	346	372	398
Earnings Per Common Share from Continuing Operations, Basic	$ 2.78	$ 2.37	$ 9.16
Net Earnings Per Common Share, Basic	$ 2.78	$ 2.40	$ 10.80
Earnings Per Common Share from Continuing Operations, Diluted	$ 2.76	$ 2.34	$ 8.97
Net Earnings Per Common Share, Diluted	$ 2.76	$ 2.37	$ 10.57
Dividends Declared Per Common Share	$ 1.32	$ 1.23	$ —

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

PG&E Corporation

(in millions)	Balance at December 31, 2006	2005
ASSETS		
Current Assets		
Cash and cash equivalents	$ 456	$ 713
Restricted cash	1,415	1,546
Accounts receivable:		
Customers (net of allowance for doubtful accounts of $50 million in 2006 and $77 million in 2005)	2,343	2,422
Regulatory balancing accounts	607	727
Inventories:		
Gas stored underground and fuel oil	181	231
Materials and supplies	149	133
Income taxes receivable	—	21
Prepaid expenses and other	716	187
Total current assets	5,867	5,980
Property, Plant and Equipment		
Electric	24,036	22,482
Gas	9,115	8,794
Construction work in progress	1,047	738
Other	16	16
Total property, plant and equipment	34,214	32,030
Accumulated depreciation	(12,429)	(12,075)
Net property, plant and equipment	21,785	19,955
Other Noncurrent Assets		
Regulatory assets	4,902	5,578
Nuclear decommissioning funds	1,876	1,719
Other	373	842
Total other noncurrent assets	7,151	8,139
TOTAL ASSETS	$ 34,803	$ 34,074

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

PG&E Corporation

(in millions, except share amounts)	Balance at December 31, 2006	2005
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-term borrowings	$ 759	$ 260
Long-term debt, classified as current	281	2
Rate reduction bonds, classified as current	290	290
Energy recovery bonds, classified as current	340	316
Accounts payable:		
Trade creditors	1,075	980
Disputed claims and customer refunds	1,709	1,733
Regulatory balancing accounts	1,030	840
Other	420	441
Interest payable	583	473
Income taxes payable	102	—
Deferred income taxes	148	181
Other	1,513	1,416
Total current liabilities	8,250	6,932
Noncurrent Liabilities		
Long-term debt	6,697	6,976
Rate reduction bonds	—	290
Energy recovery bonds	1,936	2,276
Regulatory liabilities	3,392	3,506
Asset retirement obligations	1,466	1,587
Deferred income taxes	2,840	3,092
Deferred tax credits	106	112
Other	2,053	1,833
Total noncurrent liabilities	18,490	19,672
Commitments and Contingencies (Notes 2, 4, 5, 6, 8, 9, 13, 15 and 17)		
Preferred Stock of Subsidiaries	252	252
Preferred Stock		
Preferred stock, no par value, 80,000,000 shares, $100 par value, 5,000,000 shares, none issued	—	—
Common Shareholders' Equity		
Common stock, no par value, authorized 800,000,000 shares, issued 372,803,521 common and 1,377,538 restricted shares in 2006 and issued 366,868,512 common and 1,399,990 restricted shares in 2005	5,877	5,827
Common stock held by subsidiary, at cost, 24,665,500 shares	(718)	(718)
Unearned compensation	—	(22)
Reinvested earnings	2,671	2,139
Accumulated other comprehensive loss	(19)	(8)
Total common shareholders' equity	7,811	7,218
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$34,803	$34,074

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

PG&E Corporation

(in millions)	Year ended December 31, 2006	2005	2004
Cash Flows From Operating Activities			
Net income	**$ 991**	$ 917	$ 4,504
Gain on disposal of NEGT (net of income tax benefit of $13 million in 2005 and income tax expense of $374 million in 2004)	**–**	(13)	(684)
Net income from continuing operations	**991**	904	3,820
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, amortization, decommissioning and allowance for equity funds used during construction	**1,756**	1,698	1,497
Loss from retirement of long-term debt	**–**	–	65
Tax benefit from employee stock plans	**–**	50	41
Gain on sale of assets	**(11)**	–	(19)
Recognition of regulatory assets	**–**	–	(4,900)
Deferred income taxes and tax credits, net	**(285)**	(659)	2,607
Other deferred charges and noncurrent liabilities	**151**	33	(519)
Net effect of changes in operating assets and liabilities:			
Accounts receivable	**130**	(245)	(85)
Inventories	**32**	(60)	(12)
Accounts payable	**17**	257	273
Accrued taxes/income taxes receivable	**124**	(207)	(122)
Regulatory balancing accounts, net	**329**	254	(590)
Other current assets	**(273)**	29	760
Other current liabilities	**(233)**	273	(48)
Payments authorized by the Bankruptcy Court on amounts classified as liabilities subject to compromise	**–**	–	(1,022)
Other	**(14)**	82	110
Net cash provided by operating activities	**2,714**	2,409	1,856
Cash Flows From Investing Activities			
Capital expenditures	**(2,402)**	(1,804)	(1,559)
Net proceeds from sale of assets	**17**	39	35
Decrease (increase) in restricted cash	**115**	434	(1,216)
Proceeds from nuclear decommissioning trust sales	**1,087**	2,918	1,821
Purchases of nuclear decommissioning trust investments	**(1,244)**	(3,008)	(1,972)
Other	**–**	23	(27)
Net cash used in investing activities	**(2,427)**	(1,398)	(2,918)
Cash Flows From Financing Activities			
Borrowings under accounts receivable facility and working capital facility	**350**	260	300
Repayments under accounts receivable facility and working capital facility	**(310)**	(300)	–
Net issuance of commercial paper, net of discount of $2 million	**458**	–	–
Proceeds from issuance of long-term debt, net of issuance costs of $3 million in 2005 and $107 million in 2004	**–**	451	7,742
Proceeds from issuance of energy recovery bonds, net of issuance costs of $21 million in 2005	**–**	2,711	–
Long-term debt matured, redeemed or repurchased	**–**	(1,556)	(9,054)
Rate reduction bonds matured	**(290)**	(290)	(290)
Energy recovery bonds matured	**(316)**	(140)	–
Preferred stock with mandatory redemption provisions redeemed	**–**	(122)	(15)
Preferred stock without mandatory redemption provisions redeemed	**–**	(37)	–
Common stock issued	**131**	243	162
Common stock repurchased	**(114)**	(2,188)	(378)
Common stock dividends paid	**(456)**	(334)	–
Other	**3**	32	(91)
Net cash used in financing activities	**(544)**	(1,270)	(1,624)
Net change in cash and cash equivalents	**(257)**	(259)	(2,686)
Cash and cash equivalents at January 1	**713**	972	3,658
Cash and cash equivalents at December 31	**$ 456**	$ 713	$ 972
Supplemental disclosures of cash flow information			
Cash received for:			
Reorganization interest income	**$ –**	$ –	$ 16
Cash paid for:			
Interest (net of amounts capitalized)	**503**	403	646
Income taxes paid, net	**736**	1,392	128
Reorganization professional fees and expenses	**–**	–	61
Supplemental disclosures of noncash investing and financing activities			
Common stock dividends declared but not yet paid	**$ 117**	$ 115	$ –
Transfer of liabilities and other payables subject to compromise to operating assets and liabilities	**–**	–	(2,877)
Assumption of capital lease obligation	**408**	–	–
Transfer of Gateway Generating Station asset	**69**	–	–

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

PG&E Corporation

(in millions, except share amounts)	Common Stock Shares	Common Stock Amount	Common Stock Held by Subsidiary	Unearned Compensation	Reinvested Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	Total Common Shareholders' Equity	Comprehensive Income (Loss)
Balance at December 31, 2003	**416,520,282**	**$6,468**	**$(690)**	**$(20)**	**$(1,458)**	**$(85)**	**$4,215**	
Net income	–	–	–	–	4,504	–	4,504	$4,504
Mark-to-market adjustments for hedging transactions in accordance with SFAS No. 133 (net of income tax expense of $2 million)	–	–	–	–	–	3	3	3
NEGT losses reclassified to earnings upon elimination of equity interest by PG&E Corporation (net of income tax expense of $43 million)	–	–	–	–	–	77	77	77
Other	–	–	–	–	–	1	1	1
Comprehensive income								$4,585
Common stock issued	8,410,058	162	–	–	–	–	162	
Common stock repurchased	(10,783,200)	(167)	–	–	(183)	–	(350)	
Common stock held by subsidiary	–	–	(28)	–	–	–	(28)	
Common stock warrants exercised	4,003,812	–	–	–	–	–	–	
Common restricted stock issued	498,910	16	–	(16)	–	–	–	
Common restricted stock cancelled	(33,721)	(1)	–	1	–	–	–	
Common restricted stock amortization	–	–	–	9	–	–	9	
Tax benefit from employee stock plans	–	41	–	–	–	–	41	
Other	–	(1)	–	–	–	–	(1)	
Balance at December 31, 2004	**418,616,141**	**6,518**	**(718)**	**(26)**	**2,863**	**(4)**	**8,633**	
Net income	–	–	–	–	917	–	917	$ 917
Minimum pension liability adjustment (net of income tax benefit of $3 million)	–	–	–	–	–	(4)	(4)	(4)
Comprehensive income								$ 913
Common stock issued	10,264,535	247	–	–	–	–	247	
Common stock repurchased	(61,139,700)	(998)	–	–	(1,190)	–	(2,188)	
Common stock warrants exercised	295,919	–	–	–	–	–	–	
Common restricted stock issued	347,710	13	–	(13)	–	–	–	
Common restricted stock cancelled	(116,103)	(4)	–	4	–	–	–	
Common restricted stock amortization	–	–	–	13	–	–	13	
Common stock dividends declared and paid	–	–	–	–	(334)	–	(334)	
Common stock dividends declared but not yet paid	–	–	–	–	(115)	–	(115)	
Tax benefit from employee stock plans	–	50	–	–	–	–	50	
Other	–	1	–	–	(2)	–	(1)	
Balance at December 31, 2005	**368,268,502**	**5,827**	**(718)**	**(22)**	**2,139**	**(8)**	**7,218**	
Net income	–	–	–	–	991	–	991	$ 991
Comprehensive income								$ 991
Common stock issued	5,399,707	110	–	–	–	–	110	
ASR settlement of stock repurchased in 2005	–	(114)	–	–	–	–	(114)	
Common stock warrants exercised	51,890	–	–	–	–	–	–	
Common restricted stock, unearned compensation reversed in accordance with SFAS No. 123R	–	(22)	–	22	–	–	–	
Common restricted stock issued	566,255	21	–	–	–	–	21	
Common restricted stock cancelled	(105,295)	(1)	–	–	–	–	(1)	
Common restricted stock amortization	–	20	–	–	–	–	20	
Common stock dividends declared and paid	–	–	–	–	(342)	–	(342)	
Common stock dividends declared but not yet paid	–	–	–	–	(117)	–	(117)	
Tax benefit from employee stock plans	–	35	–	–	–	–	35	
Adoption of SFAS No. 158 (net of income tax benefit of $8 million)	–	–	–	–	–	(11)	(11)	
Other	–	1	–	–	–	–	1	
Balance at December 31, 2006	**374,181,059**	**$5,877**	**$(718)**	**$ –**	**$ 2,671**	**$(19)**	**$ 7,811**	

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF INCOME

Pacific Gas and Electric Company

	Year ended December 31,		
(in millions)	2006	2005	2004
Operating Revenues			
Electric	**$ 8,752**	$ 7,927	$ 7,867
Natural gas	**3,787**	3,777	3,213
Total operating revenues	**12,539**	11,704	11,080
Operating Expenses			
Cost of electricity	**2,922**	2,410	2,770
Cost of natural gas	**2,097**	2,191	1,724
Operating and maintenance	**3,697**	3,399	2,848
Recognition of regulatory assets	**–**	–	(4,900)
Depreciation, amortization and decommissioning	**1,708**	1,734	1,494
Total operating expenses	**10,424**	9,734	3,936
Operating Income	**2,115**	1,970	7,144
Interest income	**175**	76	50
Interest expense	**(710)**	(554)	(667)
Other income, net	**7**	16	16
Income Before Income Taxes	**1,587**	1,508	6,543
Income tax provision	**602**	574	2,561
Net Income	**985**	934	3,982
Preferred stock dividend requirement	**14**	16	21
Income Available for Common Stock	**$ 971**	$ 918	$ 3,961

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

Pacific Gas and Electric Company

	Balance at December 31,	
(in millions)	2006	2005
ASSETS		
Current Assets		
Cash and cash equivalents	$ 70	$ 463
Restricted cash	1,415	1,546
Accounts receivable:		
Customers (net of allowance for doubtful accounts of $50 million in 2006 and $77 million in 2005)	2,343	2,422
Related parties	6	3
Regulatory balancing accounts	607	727
Inventories:		
Gas stored underground and fuel oil	181	231
Materials and supplies	149	133
Income taxes receivable	20	48
Prepaid expenses and other	714	183
Total current assets	5,505	5,756
Property, Plant and Equipment		
Electric	24,036	22,482
Gas	9,115	8,794
Construction work in progress	1,047	738
Total property, plant and equipment	34,198	32,014
Accumulated depreciation	(12,415)	(12,061)
Net property, plant and equipment	21,783	19,953
Other Noncurrent Assets		
Regulatory assets	4,902	5,578
Nuclear decommissioning funds	1,876	1,719
Related parties receivable	25	23
Other	280	754
Total other noncurrent assets	7,083	8,074
TOTAL ASSETS	$ 34,371	$ 33,783

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

Pacific Gas and Electric Company

(in millions, except share amounts)	Balance at December 31, 2006	2005
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-term borrowings	$ 759	$ 260
Long-term debt, classified as current	1	2
Rate reduction bonds, classified as current	290	290
Energy recovery bonds, classified as current	340	316
Accounts payable:		
Trade creditors	1,075	980
Disputed claims and customer refunds	1,709	1,733
Related parties	40	37
Regulatory balancing accounts	1,030	840
Other	402	423
Interest payable	570	460
Deferred income taxes	118	161
Other	1,346	1,255
Total current liabilities	7,680	6,757
Noncurrent Liabilities		
Long-term debt	6,697	6,696
Rate reduction bonds	–	290
Energy recovery bonds	1,936	2,276
Regulatory liabilities	3,392	3,506
Asset retirement obligations	1,466	1,587
Deferred income taxes	2,972	3,218
Deferred tax credits	106	112
Other	1,922	1,691
Total noncurrent liabilities	18,491	19,376
Commitments and Contingencies (Notes 2, 4, 5, 6, 8, 9, 13, 15 and 17)		
Shareholders' Equity		
Preferred stock without mandatory redemption provisions:		
Nonredeemable, 5.00% to 6.00%, outstanding 5,784,825 shares	145	145
Redeemable, 4.36% to 5.00%, outstanding 4,534,958 shares	113	113
Common stock, $5 par value, authorized 800,000,000 shares, issued 279,624,823 shares in 2006 and 2005	1,398	1,398
Common stock held by subsidiary, at cost, 19,481,213 shares	(475)	(475)
Additional paid-in capital	1,822	1,776
Reinvested earnings	5,213	4,702
Accumulated other comprehensive loss	(16)	(9)
Total shareholders' equity	8,200	7,650
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$34,371	$33,783

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Pacific Gas and Electric Company

(in millions)	Year ended December 31, 2006	2005	2004
Cash Flows From Operating Activities			
Net income	$ 985	$ 934	$ 3,982
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, amortization, decommissioning and allowance for equity funds used during construction	1,755	1,697	1,494
Gain on sale of assets	(11)	–	–
Recognition of regulatory assets	–	–	(4,900)
Deferred income taxes and tax credits, net	(287)	(636)	2,580
Other deferred charges and noncurrent liabilities	116	21	(391)
Net effect of changes in operating assets and liabilities:			
Accounts receivable	128	(245)	(85)
Inventories	34	(60)	(12)
Accounts payable	21	257	273
Accrued taxes/income taxes receivable	28	(150)	52
Regulatory balancing accounts, net	329	254	(590)
Other current assets	(273)	2	55
Other current liabilities	(235)	273	395
Payments authorized by the Bankruptcy Court on amounts classified as liabilities subject to compromise	–	–	(1,022)
Other	(13)	19	7
Net cash provided by operating activities	2,577	2,366	1,838
Cash Flows From Investing Activities			
Capital expenditures	(2,402)	(1,803)	(1,559)
Net proceeds from sale of assets	17	39	35
Decrease (increase) in restricted cash	115	434	(1,577)
Proceeds from nuclear decommissioning trust sales	1,087	2,918	1,821
Purchases of nuclear decommissioning trust investments	(1,244)	(3,008)	(1,972)
Other	1	61	(27)
Net cash used in investing activities	(2,426)	(1,359)	(3,279)
Cash Flows From Financing Activities			
Borrowings under accounts receivable facility and working capital facility	350	260	300
Repayments under accounts receivable facility and working capital facility	(310)	(300)	–
Net issuance of commercial paper, net of discount of $2 million	458	–	–
Proceeds from issuance of long-term debt, net of issuance costs of $3 million in 2005 and $107 million in 2004	–	451	7,742
Proceeds from issuance of energy recovery bonds, net of issuance costs of $21 million in 2005	–	2,711	–
Long-term debt matured, redeemed or repurchased	–	(1,554)	(8,402)
Rate reduction bonds matured	(290)	(290)	(290)
Energy recovery bonds matured	(316)	(140)	–
Preferred stock dividends paid	(14)	(16)	(90)
Common stock dividends paid	(460)	(445)	–
Preferred stock with mandatory redemption provisions redeemed	–	(122)	(15)
Preferred stock without mandatory redemption provisions redeemed	–	(37)	–
Common stock repurchased	–	(1,910)	–
Other	38	65	–
Net cash used in financing activities	(544)	(1,327)	(755)
Net change in cash and cash equivalents	(393)	(320)	(2,196)
Cash and cash equivalents at January 1	463	783	2,979
Cash and cash equivalents at December 31	$ 70	$ 463	$ 783
Supplemental disclosures of cash flow information			
Cash received for:			
Reorganization interest income	$ –	$ –	$ 16
Cash paid for:			
Interest (net of amounts capitalized)	476	390	512
Income taxes paid, net	897	1,397	109
Reorganization professional fees and expenses	–	–	61
Supplemental disclosures of noncash investing and financing activities			
Transfer of liabilities and other payables subject to compromise to operating assets and liabilities	$ –	$ –	$(2,877)
Equity contribution for settlement of plan of reorganization, or POR, payable	–	–	(129)
Assumption of capital lease obligation	408	–	–
Transfer of Gateway Generating Station asset	69	–	–

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

Pacific Gas and Electric Company

(in millions)	Preferred Stock Without Mandatory Redemption Provisions	Common Stock	Additional Paid-in Capital	Common Stock Held by Subsidiary	Reinvested Earnings	Accumulated Other Comprehensive Income (Loss)	Total Shareholders' Equity	Comprehensive Income (Loss)
Balance at December 31, 2003	**$294**	**$1,606**	**$1,964**	**$(475)**	**$ 1,706**	**$ (6)**	**$ 5,089**	
Net income	—	—	—	—	3,982	—	3,982	$3,982
Mark-to-market adjustments for hedging transactions in accordance with SFAS No. 133 (net of income tax expense of $2 million)	—	—	—	—	—	3	3	3
Comprehensive income								**$3,985**
Equity contribution for settlement of POR payable (net of income taxes of $52 million)	—	—	77	—	—	—	77	
Preferred stock dividend	—	—	—	—	(21)	—	(21)	
Balance at December 31, 2004	**294**	**1,606**	**2,041**	**(475)**	**5,667**	**(3)**	**9,130**	
Net income	—	—	—	—	934	—	934	$ 934
Minimum pension liability adjustment (net of income tax benefit of $4 million)	—	—	—	—	—	(6)	(6)	(6)
Comprehensive income								**$ 928**
Common stock repurchased	—	(208)	(266)	—	(1,436)	—	(1,910)	
Common stock dividend	—	—	—	—	(445)	—	(445)	
Preferred stock redeemed	(36)	—	1	—	(2)	—	(37)	
Preferred stock dividend	—	—	—	—	(16)	—	(16)	
Balance at December 31, 2005	**258**	**1,398**	**1,776**	**(475)**	**4,702**	**(9)**	**7,650**	
Net income	—	—	—	—	985	—	985	$ 985
Minimum pension liability adjustment (net of income tax expense of $2 million)	—	—	—	—	—	3	3	3
Comprehensive income								**$ 988**
Tax benefit from employee stock plans	—	—	46	—	—	—	46	
Common stock dividend	—	—	—	—	(460)	—	(460)	
Preferred stock dividend	—	—	—	—	(14)	—	(14)	
Adoption of SFAS No. 158 (net of income tax benefit of $7 million)	—	—	—	—	—	(10)	(10)	
Balance at December 31, 2006	**$258**	**$1,398**	**$1,822**	**$(475)**	**$ 5,213**	**$(16)**	**$ 8,200**	

See accompanying Notes to the Consolidated Financial Statements.

NOTE 1: ORGANIZATION AND BASIS OF PRESENTATION

PG&E Corporation is a holding company whose primary purpose is to hold interests in energy-based businesses. PG&E Corporation conducts its business principally through Pacific Gas and Electric Company, or the Utility, a public utility operating in northern and central California. The Utility engages in the businesses of electricity and natural gas distribution, electricity generation, procurement and transmission, and natural gas procurement, transportation and storage. The Utility is primarily regulated by the California Public Utilities Commission, or CPUC, and the Federal Energy Regulatory Commission, or FERC.

As discussed further in Note 15, on April 12, 2004, the Utility's plan of reorganization under the provisions of Chapter 11 of the U.S. Bankruptcy Code, or Chapter 11, became effective, and the Utility emerged from Chapter 11. The U.S. Bankruptcy Court for the Northern District of California, or Bankruptcy Court, which oversaw the Utility's Chapter 11 proceeding, retains jurisdiction, among other things, to resolve the remaining disputed Chapter 11 claims.

This is a combined annual report of PG&E Corporation and the Utility. Therefore, the Notes to the Consolidated Financial Statements apply to both PG&E Corporation and the Utility. PG&E Corporation's Consolidated Financial Statements include the accounts of PG&E Corporation, the Utility, and other wholly owned and controlled subsidiaries. The Utility's Consolidated Financial Statements include its accounts and those of its wholly owned and controlled subsidiaries and variable interest entities for which it is subject to a majority of the risk of loss or gain. All intercompany transactions have been eliminated from the Consolidated Financial Statements.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America, or GAAP, requires management to make estimates and assumptions. These estimates and assumptions affect the reported amounts of revenues, expenses, assets and liabilities and the disclosure of contingencies and include, but are not limited to, estimates and assumptions used in determining the Utility's regulatory asset and liability balances based on probability assessments of regulatory recovery, revenues earned but not yet billed (including delayed billings), disputed claims, asset retirement obligations, allowance for doubtful accounts receivable, provisions for losses that are deemed probable from environmental remediation liabilities, pension liabilities, severance costs, mark-to-market accounting under Statement of Financial Accounting Standards, or SFAS, No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended, or SFAS No. 133, income tax related liabilities, litigation, the fair value of financial instruments, and the Utility's assessment of impairment of long-lived assets and certain identifiable intangibles to be held and used whenever events or changes in circumstances indicate that the carrying amount of its assets might not be recoverable. As these estimates and assumptions involve judgments involving a wide range of factors, including future regulatory decisions and economic conditions that are difficult to predict, actual results could differ from these estimates. PG&E Corporation's and the Utility's Consolidated Financial Statements reflect all adjustments that management believes are necessary for the fair presentation of their financial position and results of operations for the periods presented.

NOTE 2: SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The accounting policies used by PG&E Corporation and the Utility include those necessary for rate-regulated enterprises, which reflect the ratemaking policies of the CPUC and the FERC.

CASH AND CASH EQUIVALENTS

Invested cash and other short-term investments with original maturities of three months or less are considered cash equivalents. Cash equivalents are stated at cost, which approximates fair value. PG&E Corporation and the Utility primarily invest their cash in money market funds and in short-term obligations of the U.S. government and its agencies.

PG&E Corporation had four account balances with institutional money market funds that were each greater than 10% of PG&E Corporation's and the Utility's total cash and cash equivalents balance at December 31, 2006.

RESTRICTED CASH

Restricted cash includes Utility amounts held in escrow pending the resolution of remaining disputed Chapter 11 claims and collateral required by the California Independent System Operator, or CAISO, the State of California and other counterparties. The Utility also provides deposits to counterparties in the normal course of operations and under certain third-party agreements.

ALLOWANCE FOR DOUBTFUL ACCOUNTS RECEIVABLE

PG&E Corporation and the Utility recognize an allowance for doubtful accounts to record accounts receivable at estimated net realizable value. The allowance is determined based upon a variety of factors, including historical write-off experience, delinquency rates, current economic conditions and assessment of customer collectibility. If circumstances require changes in the Utility's assumptions, allowance estimates are adjusted accordingly. The customer accounts receivable write-offs are recovered in rates, but limited to amounts approved by the CPUC, with any excess being borne by shareholders. In 2006, there was no significant impact to the shareholders.

INVENTORIES

Inventories are valued at average cost and include materials, supplies and gas stored underground. Materials and supplies are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, when installed. Materials reserves are made for obsolete inventory. Gas stored underground is charged to inventory at current costs when purchased and then expensed at average costs when distributed to customers.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment are reported at their original cost. Original cost includes:

- Labor and materials;
- Construction overhead; and
- Allowance for funds used during construction, or AFUDC.

AFUDC

AFUDC is the estimated cost of debt and equity used to finance regulated plant additions that can be recorded as part of the cost of construction projects. AFUDC is recoverable from customers through rates over the life of the related property once the property is placed in service. The Utility recorded AFUDC of approximately $47 million and $20 million related to equity and debt, respectively, during 2006, $37 million and $14 million related to equity and debt, respectively, during 2005, and $20 million and $12 million related to equity and debt, respectively, during 2004. PG&E Corporation on a stand-alone basis did not have any capitalized interest or AFUDC in 2006, 2005 and 2004.

Depreciation

The Utility's composite depreciation rate was 3.09% in 2006, 3.28% in 2005 and 3.42% in 2004.

(in millions)	Gross Plant As of December 31, 2006	Estimated Useful Lives
Electricity generating facilities	$ 2,068	15 to 44 years
Electricity distribution facilities	15,305	16 to 58 years
Electricity transmission	4,397	40 to 70 years
Natural gas distribution facilities	5,028	23 to 54 years
Natural gas transportation	3,016	25 to 45 years
Natural gas storage	48	25 to 48 years
Other	3,289	5 to 40 years
Total	$33,151	

The useful lives of the Utility's property, plant and equipment are authorized by the CPUC and the FERC and depreciation expense is included within the recoverable costs of service included in rates charged to customers. Depreciation expense includes a component for the original cost of assets and a component for estimated future removal and remediation costs, net of any salvage value at retirement. The Utility has a separate rate it collects from customers for the accrual of its recorded obligation for nuclear decommissioning that is included in depreciation, amortization and decommissioning expense in the accompanying Consolidated Statements of Income.

PG&E Corporation and the Utility charge the original cost of retired plant less salvage value to accumulated depreciation upon retirement of plant in service in accordance with SFAS No. 71 "Accounting for the Effects of Certain Types of Regulation" as amended, or SFAS No. 71. PG&E Corporation and the Utility expense repair and maintenance costs as incurred.

Nuclear Fuel

Property, plant and equipment also includes nuclear fuel inventories. Stored nuclear fuel inventory is stated at weighted average cost. Nuclear fuel in the reactor is expensed as used based on the amount of energy output.

Capitalized Software Costs

PG&E Corporation and the Utility account for internal software in accordance with Statement of Position, "Accounting for the Costs of Computer Software Developed or Obtained for Internal Use," or SOP 98-1.

Under SOP 98-1, PG&E Corporation and the Utility capitalize costs incurred during the application development stage of internal use software projects to property, plant and equipment. Capitalized software costs totaled $237 million at December 31, 2006 and $201 million at December 31, 2005, net of accumulated amortization of approximately $197 million at December 31, 2006 and $168 million at December 31, 2005. PG&E Corporation and the Utility expense capitalized software costs ratably over the expected lives of the software ranging from 3 to 15 years, commencing upon operational use.

REGULATION AND STATEMENT OF FINANCIAL ACCOUNTING STANDARDS NO. 71

PG&E Corporation and the Utility account for the financial effects of regulation in accordance with SFAS No. 71. SFAS No. 71 applies to regulated entities whose rates are designed to recover the costs of providing service. SFAS No. 71 applies to all of the Utility's operations.

Under SFAS No. 71, incurred costs that would otherwise be charged to expense may be capitalized and recorded as regulatory assets if it is probable that the incurred costs will be recovered in rates in the future. The regulatory assets are amortized over future periods consistent with the inclusion of costs in authorized customer rates. If costs that a regulated enterprise expects to incur in the future are being recovered through rates, SFAS No. 71 requires that the regulated enterprise record those expected future costs as regulatory liabilities. In addition, amounts that are probable of being credited or refunded to customers in the future must be recorded as regulatory liabilities.

To the extent that portions of the Utility's operations cease to be subject to SFAS No. 71 or recovery is no longer probable as a result of changes in regulation or other reasons, the related regulatory assets and liabilities are written off. No such write-offs took place in 2006, 2005 and 2004.

OTHER INTANGIBLE ASSETS

Other intangible assets consist of hydroelectric facility licenses and other agreements, with lives ranging from 19 to 40 years. The gross carrying amount of the hydroelectric facility licenses and other agreements was approximately $73 million at December 31, 2006 and December 31, 2005. The accumulated amortization was approximately $28 million at December 31, 2006 and $25 million at December 31, 2005.

The Utility's amortization expense related to intangible assets was approximately $3 million in 2006, $3 million in 2005 and $4 million in 2004. The estimated annual amortization expense based on the December 31, 2006, intangible asset balance for the Utility's intangible assets for 2007 through 2011 is approximately $3 million each year. Intangible assets are recorded to Other Noncurrent Assets on the Consolidated Balance Sheets.

INVESTMENTS IN AFFILIATES

The Utility has investments in unconsolidated affiliates, which are mainly limited partnerships engaged in the purchase of low-income residential real estate property. The equity method of accounting is applied to the Utility's investment in these partnerships. Under the equity method, the Utility's share of equity income or losses of these partnerships is reflected as other operating income or expense in its Consolidated Statements of Income. As of December 31, 2006, the Utility's recorded investment in these entities totaled approximately $4 million. As a limited partner, the Utility's exposure to potential loss is limited to its investment in each partnership.

CONSOLIDATION OF VARIABLE INTEREST ENTITIES

The Financial Accounting Standards Board, or FASB, Interpretation No. 46 (revised December 2003), "Consolidation of Variable Interest Entities," or FIN 46R, provides that an entity is a variable interest entity, or VIE, if it does not have sufficient equity investment at risk, or if the holders of the entity's equity instruments lack the essential characteristics of a controlling financial interest. FIN 46R requires that the holder subject to a majority of the risk of loss from a VIE's activities must consolidate the VIE. However, if no holder has a majority of the risk of loss, then a holder entitled to receive a majority of the entity's residual returns would consolidate the entity. In accordance with FIN 46R, the Utility consolidated the assets, liabilities and non-controlling interests of a low-income housing partnership that was determined to be a VIE under FIN 46R. The impact of the VIE was immaterial to the Consolidated Financial Statements and operations of PG&E Corporation and the Utility.

The nature of power purchase agreements is such that the Utility could have a significant variable interest in a power purchase agreement counterparty if that entity is a VIE owning one or more plants that sell substantially all of their output to the Utility, and the contract price for power is correlated with the plant's variable costs of production. As of December 31, 2006, the Utility did not have any power purchase agreements meeting these criteria.

IMPAIRMENT OF LONG-LIVED ASSETS

The carrying values of long-lived assets are evaluated in accordance with the provisions of SFAS No. 144, "Accounting for the Impairment of Long-Lived Assets," or SFAS No. 144. In accordance with SFAS No. 144, PG&E Corporation and the Utility evaluate the carrying amounts of long-lived assets for impairment whenever events occur or circumstances change that may affect the recoverability or the estimated life of long-lived assets.

ASSET RETIREMENT OBLIGATIONS

PG&E Corporation and the Utility account for asset retirement obligations in accordance with SFAS No. 143, "Accounting for Asset Retirement Obligations," or SFAS No. 143, and FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations – an Interpretation of FASB Statement No. 143," or FIN 47. SFAS No. 143 requires that an asset retirement obligation be recorded at fair value in the period in which it is incurred if a reasonable estimate of fair value can be made. In the same period, the associated asset retirement costs are capitalized as part of the carrying amount of the related long-lived asset. In each subsequent period, the liability is accreted to its present value; and the capitalized cost is depreciated over the useful life of the long-lived asset. Rate-regulated entities may recognize regulatory assets or liabilities as a result of timing differences between the recognition of costs as recorded in accordance with SFAS No. 143 and costs recovered through the ratemaking process. FIN 47 clarifies that if a legal obligation to perform an asset retirement obligation exists but performance is conditional upon a future event, and the obligation can be reasonably estimated, then a liability should be recognized in accordance with SFAS No. 143.

The Utility has also identified its nuclear generation and certain fossil fuel generation facilities as having asset retirement obligations under SFAS No. 143. In accordance with FIN 47, the Utility recognized asset retirement obligations related to asbestos contamination in buildings, potential site restoration at certain hydroelectric facilities, fuel storage tanks and contractual obligations to restore leased property to pre-lease condition. Additionally, the Utility recognized asset retirement obligations related to the California Gas Transmission pipeline, Gas Distribution, Electric Distribution and Electric Transmission system assets.

A reconciliation of the changes in the ARO liability is as follows:

(in millions)	
ARO liability at December 31, 2004	$1,301
Recognition of FIN 47 obligation	203
Accretion expense	85
Liabilities settled	(2)
ARO liability at December 31, 2005	1,587
Revision in estimated cash flows	(204)
Accretion expense	98
Liabilities settled	(15)
ARO liability at December 31, 2006	**$1,466**

The Utility has identified additional asset retirement obligations for which a reasonable estimate of fair value could not be made. The Utility has not recognized a liability related to these additional obligations which include: obligations to restore land to its pre-use condition under the terms of certain land rights agreements, removal and proper disposal of lead-based paint contained in some PG&E facilities, removal of certain communications equipment from leased property and retirement activities associated with substation and certain hydroelectric facilities. The Utility was not able to reasonably estimate the asset retirement obligation associated with these assets because the settlement date of the obligation was indeterminate and information sufficient to reasonably estimate the settlement date or range of settlement dates does not exist. Land rights, communication equipment leases and substation facilities will be maintained for the foreseeable future, and the Utility cannot reasonably estimate the settlement date or range of settlement dates for the obligations associated with these assets. The Utility does not have information available that specifies which facilities contain lead-based paint and therefore cannot reasonably estimate the settlement date(s) associated with the obligation. The Utility will maintain and continue to operate its hydroelectric facilities until operation of a facility therefore becomes uneconomic. The operation of the majority of the Utility's hydroelectric facilities is currently and for the foreseeable future economic, and the settlement date cannot be determined at this time.

FAIR VALUE OF 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. The fair value may be significantly different than the carrying amount of financial instruments that are recorded at historical amounts.

PG&E Corporation and the Utility use the following methods and assumptions in estimating fair value for financial instruments:

- The fair values of cash and cash equivalents, restricted cash and deposits, net accounts receivable, price risk management assets and liabilities, short-term borrowings, accounts payable, customer deposits and the Utility's variable rate pollution control bond loan agreements approximate their carrying values as of December 31, 2006 and 2005; and
- The fair values of the Utility's fixed rate senior notes and fixed rate pollution control bond loan agreements, PG&E Funding, LLC's rate reduction bonds, PG&E Energy Recovery Funding, LLC's energy recovery bonds, or ERBs, and PG&E Corporation's 9.50% Convertible Subordinated Notes, were based on quoted market prices obtained from the Bloomberg financial information system at December 31, 2006.

The carrying amount and fair value of PG&E Corporation's and the Utility's financial instruments are as follows (the table below excludes financial instruments with fair values that approximate their carrying values, as these instruments are presented at their carrying value in the Consolidated Balance Sheets):

	At December 31,			
	2006		2005	
(in millions)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Debt (Note 4):				
PG&E Corporation	**$ 280**	**$ 937**	$ 280	$ 783
Utility	**5,629**	**5,616**	5,628	5,720
Rate reduction bonds (Note 5)	**290**	**292**	580	591
Energy recovery bonds (Note 6)	**2,276**	**2,239**	2,592	2,558

GAINS AND LOSSES ON DEBT EXTINGUISHMENTS

Gains and losses on debt extinguishments associated with regulated operations that are subject to the provisions of SFAS No. 71 are deferred and amortized over the remaining original amortization period of the debt reacquired, consistent with recovery of costs through regulated rates. Gains and losses on debt extinguishments associated with unregulated operations are fully recognized at the time such debt is reacquired and are reported as a component of interest expense.

ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

Accumulated other comprehensive income (loss) reports a measure for accumulated changes in equity of an enterprise that result from transactions and other economic events, other than transactions with shareholders. The following table sets forth the changes in each component of accumulated other comprehensive income (loss):

(in millions)	Hedging Transactions in Accordance with SFAS No. 133	Foreign Currency Translation Adjustment	Minimum Pension Liability Adjustment	Adoption of SFAS No. 158	Other	Accumulated Other Comprehensive Income (Loss)
Balance at December 31, 2003	**$(81)**	**$–**	**$(4)**	**$ –**	**$–**	**$(85)**
Period change in:						
Mark-to-market adjustments for hedging transactions in accordance with SFAS No. 133	3	–	–	–	–	3
NEGT losses reclassified to earnings upon elimination of equity interest by PG&E Corporation	77	–	–	–	–	77
Other	–	–	–	–	1	1
Balance at December 31, 2004	**(1)**	**–**	**(4)**	**–**	**1**	**(4)**
Period change in:						
Minimum pension liability adjustment	–	–	(4)	–	–	(4)
Other	1	–	–	–	(1)	–
Balance at December 31, 2005	**–**	**–**	**(8)**	**–**	**–**	**(8)**
Period change in:						
Adoption of SFAS No. 158	–	–	8	(19)	–	(11)
Balance at December 31, 2006	**$ –**	**$–**	**$–**	**$(19)**	**$–**	**$(19)**

Accumulated other comprehensive income (loss) included losses related to discontinued operations recognized in connection with PG&E Corporation's cancellation of its equity interest in National Energy & Gas Transmission, Inc., or NEGT, of approximately $77 million at December 31, 2004. Excluding the activity related to NEGT, there was no material difference between PG&E Corporation's and the Utility's accumulated other comprehensive income (loss) for the periods presented above.

REVENUE RECOGNITION

Electricity revenues, which are comprised of revenue from generation, transmission and distribution services, are billed to the Utility's customers at the CPUC-approved "bundled" electricity rate. The "bundled" electricity rate also includes the rate component set by the FERC for electric transmission services. Natural gas revenues, which are comprised of transmission and distribution services, are also billed at CPUC-approved rates. The Utility's revenues are recognized as electricity and natural gas are delivered, and include amounts for services rendered but not yet billed at the end of each year.

As further discussed in Note 17, in January 2001, the California Department of Water Resources, or DWR, began purchasing electricity to meet the portion of demand of the California investor-owned electric utilities that was not being satisfied from their own generation facilities and existing electricity contracts. Under California law, the DWR is deemed to sell the electricity directly to the Utility's retail customers, not to the Utility. The Utility acts as a pass-through entity for electricity purchased by the DWR on behalf of its customers. Although charges for electricity provided by the DWR are included in the amounts the Utility bills its customers, the Utility deducts the amounts passed through to the DWR from its electricity revenues. The pass-through amounts are based on the quantities of electricity provided by the DWR that are consumed by customers at the CPUC-approved remittance rate. These pass-through amounts are excluded from the Utility's electricity revenues in its Consolidated Statements of Income.

EARNINGS PER SHARE

PG&E Corporation applies the treasury stock method of reflecting the dilutive effect of outstanding stock-based compensation in the calculation of diluted earnings per common share, or EPS, in accordance with SFAS No. 128, "Earnings Per Share," or SFAS No. 128. Under SFAS No. 128, PG&E Corporation is required to assume that shares underlying stock options, other stock-based compensation and warrants are issued and that the proceeds received by PG&E Corporation from the exercise of these options and warrants are assumed to be used to purchase common shares at the average market price during the reported period. The incremental shares, the difference between the number of shares assumed to have been issued upon exercise and the number of shares assumed to have been purchased, is included in weighted average common shares outstanding for the purpose of calculating diluted EPS.

INCOME TAXES

PG&E Corporation and the Utility use the liability method of accounting for income taxes. Income tax expense (benefit) includes current and deferred income taxes resulting from operations during the year. Investment tax credits are amortized over the life of the related property. Other tax credits, mainly synthetic fuel tax credits, are recognized in income as earned.

PG&E Corporation files a consolidated U.S. federal income tax return that includes domestic subsidiaries in which its ownership is 80% or more. In addition, PG&E Corporation files combined state income tax returns where applicable. PG&E Corporation and the Utility are parties to a tax-sharing arrangement under which the Utility determines its income tax provision (benefit) on a stand-alone basis.

Prior to July 8, 2003, the date that PG&E Corporation's former subsidiary, NEGT, filed a Chapter 11 petition, PG&E Corporation applied the liability method to recognize federal income tax benefits related to the losses of NEGT and its subsidiaries for financial statement purposes. After July 7, 2003, PG&E Corporation applied the cost method of accounting with respect to the losses of NEGT and its subsidiaries and has not recognized additional income tax benefits in its financial statements. PG&E Corporation was required to continue to include NEGT and its subsidiaries in its consolidated income tax returns covering all periods through October 29, 2004, the effective date of NEGT's plan of reorganization and the cancellation of PG&E Corporation's equity ownership in NEGT. See Note 11 of the Notes to the Consolidated Financial Statements for further discussion.

ACCOUNTING FOR DERIVATIVES AND HEDGING ACTIVITIES

The Utility engages in price risk management activities to manage its exposure to fluctuations in commodity prices and interest rates in its non-trading portfolio. Price risk management activities involve entering into contracts to procure electricity, natural gas, nuclear fuel and firm transmission rights for electricity.

The Utility uses a variety of derivative instruments, such as physical forwards and options, exchange traded futures and options, commodity swaps, firm transmission rights for electricity and other contracts. Derivative instruments are recorded on PG&E Corporation's and the Utility's Consolidated Balance Sheets at fair value. Changes in the fair value of derivative instruments are recorded in earnings, or to the extent they are recoverable through regulated rates, are deferred and recorded in regulatory accounts. Derivative instruments may be designated as cash flow hedges when they are entered into to hedge variable price risk associated with the purchase of commodities. For cash flow hedges, fair value changes are deferred in accumulated other comprehensive income and recognized in earnings as the hedged transactions occur, unless they are recovered in rates, in which case, they are recorded in a regulatory balancing account. Derivative instruments are presented in other current and noncurrent assets or other current and noncurrent liabilities unless they meet certain exemptions.

In order for a derivative instrument to be designated as a cash flow hedge, the relationship between the derivative instrument and the hedged item or transaction must be highly effective. The effectiveness test is performed at the inception of the hedge and each reporting period thereafter, throughout the period that the hedge is designated as such. Unrealized gains and losses related to the effective and ineffective portions of the change in the fair value of the derivative instrument, to the extent they are recoverable through rates, are deferred and recorded in regulatory accounts.

Cash flow hedge accounting is discontinued prospectively if it is determined that the derivative instrument no longer qualifies as an effective hedge, or when the forecasted transaction is no longer probable of occurring. If cash flow hedge accounting is discontinued, the derivative instrument continues to be reflected at fair value, with any subsequent changes in fair value recognized immediately in earnings. Gains and losses previously recorded in accumulated other comprehensive income (loss) will remain there until the hedged item is recognized in earnings, unless the forecasted transaction is probable of not occurring, in which case the gains and losses from the derivative instrument will be immediately recognized in earnings. A hedged item is recognized in earnings when it matures or is exercised. Any gains and losses that would have been recognized in earnings or deferred in accumulated other comprehensive income (loss), to the extent they are recoverable through rates, are deferred and recorded in regulatory accounts.

Net realized and unrealized gains or losses on derivative instruments are included in various items on PG&E Corporation's and the Utility's Consolidated Statements of Income, including cost of electricity and cost of natural gas. Cash inflows and outflows associated with the settlement of price risk management activities are recognized in operating cash flows on PG&E Corporation's and the Utility's Consolidated Statements of Cash Flows.

The fair value of contracts is estimated using the mid-point of quoted bid and ask forward prices, including quotes from counterparties, brokers, electronic exchanges and published indices, supplemented by online price information from news services. When market data is not available, proprietary models are used to estimate fair value.

The Utility has derivative instruments for the physical delivery of commodities transacted in the normal course of business as well as non-financial assets that are not exchange-traded. These derivative instruments are eligible for the normal purchase and sales and non-exchange traded contract exceptions under SFAS No. 133, and are not reflected on the balance sheet at fair value. They are recorded and recognized in income using accrual accounting. Therefore, expenses are recognized as incurred.

The Utility has certain commodity contracts for the purchase of nuclear fuel and core gas transportation and storage contracts that are not derivative instruments and are not reflected on the balance sheet at fair value. Expenses are recognized as incurred.

See Note 12 of the Notes to the Consolidated Financial Statements.

ADOPTION OF NEW ACCOUNTING PRONOUNCEMENTS

Variable Interest Entities

In April 2006, the FASB issued Staff Position No. FIN 46R-6, "Determining the Variability to Be Considered in Applying FASB Interpretation No. 46R," or FSP FIN 46R-6. FSP FIN 46R-6 specifies how a company should determine variability in applying the accounting standard for consolidation of variable interest entities. The pronouncement states that variability shall be determined based on an analysis of the design of the entity, including the nature of the risks in the entity, the purpose for which the entity was created and the variability that the entity is designed to create and pass along to its interest holders. PG&E Corporation and the Utility adopted FSP FIN 46R-6 on July 1, 2006. The adoption of FSP FIN 46R-6 did not have a material impact on the Consolidated Financial Statements of PG&E Corporation or the Utility for 2006.

Share-Based Payment

On January 1, 2006, PG&E Corporation and the Utility adopted the provisions of SFAS No. 123R, "Share-Based Payment," or SFAS No. 123R, using the modified prospective application method which requires that compensation cost be recognized for all share-based payment awards, including unvested stock options, based on the grant-date fair value. SFAS No. 123R requires that an estimate of future forfeitures be made and that compensation cost be recognized only for share-based payment awards that are expected to vest. Prior to January 1, 2006, PG&E Corporation and the Utility accounted for share-based payment awards, such as stock options, restricted stock and other share-based incentive awards, under the recognition and measurement provisions of Accounting Principles Board, or APB, Opinion No. 25, "Accounting for Stock Issued to Employees," or Opinion 25, as permitted by SFAS No. 123, "Accounting for Stock-Based Compensation," or SFAS No. 123. Under the provisions of Opinion 25, PG&E Corporation and the Utility did not recognize compensation cost for stock options for periods prior to January 1, 2006, because the exercise prices of all stock options were equal to the market value of the underlying common stock on the date of grant of the options.

For 2006, PG&E Corporation's and the Utility's operating income, income before income taxes, net income, and basic and diluted EPS were lower under SFAS No. 123R than if they had continued to account for share-based payments under Opinion 25. The following table shows the reduction in these items as a result of the adoption of SFAS No. 123R:

	PG&E Corporation	Utility
(in millions except per share amounts)	Year ended December 31, 2006	Year ended December 31, 2006
Operating Income	$ (18)	$(13)
Income Before Income Taxes	(18)	(13)
Net Income	(11)	(8)
Earnings Per Common Share, Basic	$(0.04)	
Earnings Per Common Share, Diluted	$(0.04)	

The impact on net income for 2006 is primarily attributed to the prospective application of accounting for share-based payment awards with terms that accelerate vesting on retirement and expense recognition of previously unvested stock options.

Prior to the adoption of SFAS No. 123R, PG&E Corporation and the Utility expensed share-based awards over the stated vesting period regardless of terms that accelerate vesting upon retirement. Subsequent to the adoption of SFAS No. 123R, PG&E Corporation and the Utility recognize compensation expense for all awards over the shorter of the stated vesting period or the requisite service period. If awards granted prior to adopting SFAS No. 123R were expensed over the requisite service period instead of the stated vesting period, there would have been an immaterial impact on the Consolidated Financial Statements of PG&E Corporation and the Utility for 2006.

Prior to the adoption of SFAS No. 123R, PG&E Corporation and the Utility presented all tax benefits from share-based payment awards as operating cash flows in the Consolidated Statements of Cash Flows. SFAS No. 123R requires that cash flows from the tax benefits resulting from tax deductions in excess of the compensation cost recognized for those awards (excess tax benefits) be classified as financing cash flows. PG&E Corporation's and the Utility's excess tax benefit of $35 million and $46 million, respectively, would have been classified as an operating cash inflow if PG&E Corporation and the Utility had not adopted SFAS No. 123R (see Note 14 for further discussion of share-based compensation).

The tables below show the effect on PG&E Corporation's net income and EPS if PG&E Corporation and the Utility had elected to account for stock-based compensation using the fair-value method under SFAS No. 123 based on the valuation assumptions disclosed in Note 14, for the years ended December 31, 2005 and 2004:

	Year ended December 31,	
(in millions, except per share amounts)	2005	2004
Net earnings:		
As reported	$ 917	$4,504
Deduct: Incremental stock-based employee compensation expense determined under the fair value based method for all awards, net of related tax effects	(12)	(14)
Pro forma	$ 905	$4,490
Basic earnings per share:		
As reported	$2.40	$10.80
Pro forma	2.37	10.77
Diluted earnings per share:		
As reported	2.37	10.57
Pro forma	2.33	10.59

If compensation expense had been recognized using the fair value based method under SFAS No. 123, the Utility's pro forma consolidated earnings would have been as follows:

	Year ended December 31,	
(in millions)	2005	2004
Net earnings:		
As reported	$918	$3,961
Deduct: Incremental stock-based employee compensation expense determined under the fair value based method for all awards, net of related tax effects	(7)	(8)
Pro forma	$911	$3,953

Accounting Changes and Error Corrections

On January 1, 2006, PG&E Corporation and the Utility adopted SFAS No. 154, "Accounting Changes and Error Corrections," or SFAS No. 154. SFAS No. 154 replaces APB Opinion No. 20, "Accounting Changes," and SFAS No. 3, "Reporting Accounting Changes in Interim Financial Statements." SFAS No. 154 requires retrospective application to prior periods' financial statements of changes in accounting principle unless it is impracticable. SFAS No. 154 applies to all voluntary changes in accounting principle. It also applies to changes required by a new accounting pronouncement unless the new pronouncement includes contrary explicit transition provisions. The adoption of SFAS No. 154 did not have an impact on the Consolidated Financial Statements of PG&E Corporation or the Utility for 2006.

CHANGES IN ACCOUNTING FOR CERTAIN DERIVATIVE CONTRACTS

Derivatives Implementation Group, or DIG, Issue No. B38, "Embedded Derivatives: Evaluation of Net Settlement with Respect to the Settlement of a Debt Instrument through Exercise of an Embedded Put Option or Call Option," or DIG B38, and DIG Issue No. B39 "Embedded Derivatives: Application of Paragraph 13(b) to Call Options That Are Exercisable Only by the Debtor," or DIG B39, address the circumstances in which a put or call option embedded in a debt instrument would be bifurcated from the debt instrument and accounted for separately. DIG B38 and DIG B39 were effective beginning in the first quarter of 2006. The adoption of DIG B38 and DIG B39 did not have a material impact on the Consolidated Financial Statements of PG&E Corporation or the Utility for 2006.

Accounting for Defined Benefit Pensions and Other Postretirement Plans

On December 31, 2006, PG&E Corporation and the Utility adopted SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)," or SFAS No. 158. SFAS No. 158 requires the funded status of an entity's plans to be recognized on the balance sheet, eliminates the additional minimum liability, and enhances related disclosure requirements. The funded status of a plan, as measured under SFAS No. 158, is the difference between the fair value of plan assets and the projected benefit obligation for a pension plan and the accumulated postretirement benefit obligation for other postretirement benefit plans. SFAS No. 158 also requires an entity to measure the funded status of a plan as of the date of its year-end balance sheet; PG&E Corporation and the Utility use a December 31 measurement date and therefore no adjustments are needed to comply with this requirement of SFAS No. 158. SFAS No. 158 does not change the method of recording expense on the statement of income; therefore, the effects of adopting SFAS No. 158 did not have an impact on earnings or on cash flows.

Upon adoption of SFAS No. 158, PG&E Corporation and the Utility recorded a net benefit liability equal to the underfunded status of certain pension and other postretirement benefit plans at December 31, 2006 in the amounts of $124 million and $83 million, respectively. In addition, PG&E Corporation and the Utility recorded a net pension benefit asset equal to the overfunded status of certain pension plans in the amount of $34 million at December 31, 2006. On December 31, 2006, the unrecognized prior service costs, unrecognized gains and losses, and unrecognized net transition obligations were recognized as components of accumulated other comprehensive income, net of tax (see Note 14 for further discussion). At December 31, 2006, PG&E Corporation's and the Utility's accumulated other comprehensive income included losses of approximately $19 million and $16 million, respectively, related to pensions and other postretirement benefits.

Rate-regulated entities may recognize regulatory assets or liabilities as a result of timing differences between the recognition of costs as recorded in accordance with SFAS No. 87 and costs recovered through the ratemaking process. As a result of the adoption of SFAS No. 158, the Utility reduced the existing pension regulatory liability by approximately $574 million related to the defined benefit pension plan for amounts that would otherwise be charged to accumulated other comprehensive income under SFAS No. 158. At December 31, 2006 the Utility has a net regulatory liability of approximately $23 million. The Utility has not recorded a regulatory asset for the SFAS No. 158 charge related to the other postretirement plans as a result of its funding approach and rate recovery method. The expenses associated with these plans are accounted for under SFAS No. 106, and rate recovery is based on the lesser of the SFAS No. 106 expense or the annual tax-deductible contributions to the appropriate trusts.

ACCOUNTING PRONOUNCEMENTS ISSUED BUT NOT YET ADOPTED

Accounting for Uncertainty in Income Taxes

In July 2006, the FASB issued FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes," or FIN 48. FIN 48 clarifies the accounting for uncertainty in income taxes. FIN 48 prescribes a two-step process in the recognition and measurement of a tax position taken or expected to be taken in a tax return. The first step is to determine if it is more likely than not that a tax position will be sustained upon examination by taxing authorities. If this threshold is met, the second step is to measure the tax position on the balance sheet by using the largest amount of benefit that is greater than 50% likely of being realized upon ultimate settlement. FIN 48 also requires additional disclosures. FIN 48 is effective prospectively for fiscal years beginning after December 15, 2006. PG&E Corporation and the Utility are currently evaluating the impact of FIN 48.

Fair Value Measurements

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements," or SFAS No. 157. SFAS No. 157 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. SFAS No. 157 also establishes a framework for measuring fair value and provides for expanded disclosures about fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007. PG&E Corporation and the Utility are currently evaluating the impact of SFAS No. 157.

Fair Value Option

In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities," or SFAS No. 159. SFAS No. 159 establishes a fair value option under which entities can elect to report certain financial assets and liabilities at fair value, with changes in fair value recognized in earnings. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. PG&E Corporation and the Utility are currently evaluating the impact of SFAS No. 159.

NOTE 3: REGULATORY ASSETS, LIABILITIES AND BALANCING ACCOUNTS

REGULATORY ASSETS

As discussed in Note 2, PG&E Corporation and the Utility account for the financial effects of regulation in accordance with SFAS No. 71. Long-term regulatory assets are comprised of the following:

	Balance at December 31,	
(in millions)	2006	2005
Energy recovery bond regulatory asset	**$2,170**	$2,509
Utility retained generation regulatory assets	**1,018**	1,099
Regulatory assets for deferred income tax	**599**	536
Environmental compliance costs	**303**	310
Unamortized loss, net of gain, on reacquired debt	**295**	321
Regulatory assets associated with plan of reorganization	**147**	163
Post-transition period contract termination costs	**120**	131
Scheduling coordinator costs	**111**	–
Rate reduction bond regulatory asset	**–**	456
Other	**139**	53
Total regulatory assets	**$4,902**	$5,578

The ERB represents refinancing of the settlement regulatory asset established under the December 19, 2003 settlement agreement among PG&E Corporation, the Utility and the CPUC to resolve the Utility's Chapter 11 proceeding, or the Chapter 11 Settlement Agreement. During 2006, the Utility recorded amortization of the ERB regulatory asset of approximately $339 million and expects to fully recover this asset by the end of 2012.

As a result of the Chapter 11 Settlement Agreement, the Utility recognized a one-time non-cash gain of $1.2 billion, pre-tax ($0.7 billion, after-tax), for the Utility retained generation regulatory assets in the first quarter of 2004. The individual components of these regulatory assets will be amortized over their respective lives, with a weighted average life of approximately 16 years. During 2006, the Utility recorded amortization of the Utility's retained generation regulatory assets of approximately $81 million.

The regulatory assets for deferred income tax represent deferred income tax benefits passed through to customers and are offset by deferred income tax liabilities. Tax benefits to customers have been passed through as the CPUC requires utilities under its jurisdiction to follow the "flow through" method of passing certain tax benefits to customers. The "flow through" method ignores the effect of deferred taxes on rates. Based on current regulatory ratemaking and income tax laws, the Utility expects to recover deferred income tax related to regulatory assets over periods ranging from 1 to 40 years.

Environmental compliance costs represent the portion of estimated environmental remediation liabilities that the Utility expects to recover in future rates as remediation costs are incurred. The Utility expects to recover these costs over periods ranging from 1 to 30 years.

Unamortized loss, net of gain, on reacquired debt represents costs related to debt reacquired or redeemed prior to maturity with associated discount and debt issuance costs. These costs are expected to be recovered over the remaining original amortization period of the reacquired debt over the next 1 to 21 years.

Regulatory assets associated with the plan of reorganization include costs incurred in financing the Utility's exit from Chapter 11 and costs to oversee the environmental enhancement of the Pacific Forest and Watershed Stewardship Council, an entity that was established pursuant to the Utility's plan of reorganization. The Utility expects to recover these costs over periods ranging from 5 to 30 years.

Post-transition period contract termination costs represent amounts that the Utility incurred in terminating a 30-year power purchase agreement. This regulatory asset will be amortized and collected in rates on a straight-line basis until the end of September 2014, the power purchase agreement's original termination date.

The regulatory asset related to scheduling coordinator, or SC, costs represents costs that the Utility incurred beginning in 1998 in its capacity as a scheduling coordinator for its existing wholesale transmission customers. The Utility expects to fully recover the SC costs by 2009.

Rate reduction bond, or RRB, regulatory assets represent electric industry restructuring costs that the Utility expects to collect over the term of the RRBs. During the year ended December 31, 2006, the Utility recorded amortization of the RRB regulatory asset of approximately $266 million. The remaining balance is included in current regulatory assets as the RRBs are scheduled to mature December 26, 2007. The Utility expects to fully recover the RRB regulatory asset by the end of 2007.

Finally, as of December 31, 2006, "Other," is primarily related to price risk management contracts entered into by the Utility to procure electricity and natural gas to reduce commodity price risks, which are accounted for as derivatives under SFAS No. 133. The costs and proceeds of these derivative instruments are recovered or refunded in regulated rates charged to customers. At December 31, 2005, the balance of "Other" consisted primarily of asset retirement obligation costs (see further discussion below) and vegetation management costs.

In general, the Utility does not earn a return on regulatory assets where the related costs do not accrue interest. Accordingly, the Utility earns a return only on the Utility retained generation regulatory assets, unamortized loss, net of gain on reacquired debt and regulatory assets associated with the plan of reorganization.

Current Regulatory Assets

As of December 31, 2006, the Utility had current regulatory assets of approximately $434 million, consisting primarily of the current portion of the RRB regulatory asset and price risk management contracts. These amounts are included in Prepaid Expenses and Other on the Consolidated Balance Sheets. At December 31, 2005, the amount of current regulatory assets was immaterial.

REGULATORY LIABILITIES

Long-term regulatory liabilities are comprised of the following:

	Balance at December 31,	
(in millions)	2006	2005
Cost of removal obligation	$2,340	$2,141
Asset retirement costs	608	538
Public purpose programs	169	154
Price risk management	37	213
Employee benefit plans	23	195
Rate reduction bond regulatory liability	—	157
Other	215	108
Total regulatory liabilities	$3,392	$3,506

Cost of removal represents revenues collected for asset removal costs that the Utility expects to incur in the future. Asset retirement costs represent timing differences between the recognition of asset retirement obligations and the amounts recognized for ratemaking purposes in accordance with GAAP under SFAS No. 143 and FIN 47, as applied to rate-regulated entities. Public purpose programs represent revenues designated for public purpose program costs that are expected to be incurred in the future. Price risk management represents contracts entered into by the Utility to procure electricity and natural gas that are accounted for as derivative instruments under SFAS No. 133. Additionally, the Utility hedges natural gas in the electric and natural gas portfolios on behalf of its customers to reduce commodity price risk. The costs and proceeds of these derivatives are recovered in regulated rates charged to customers. Employee benefit plan expenses represent the cumulative differences between expenses recognized for financial accounting purposes and expenses recognized for ratemaking purposes. These balances will be charged against expense to the extent that future financial accounting expenses exceed amounts recoverable for regulatory purposes. Rate reduction bonds, or RRBs, represent the deferral of over-collected revenue associated with the RRBs that the Utility expects to return to customers in the future. Finally, as of December 31, 2006, "Other" regulatory liabilities are primarily related to hazardous substance insurance recoveries and the Gateway Generating Station, or Gateway, which was acquired as part of a settlement with Mirant Corporation. The liability related to Gateway will be amortized over 30 years beginning March 2009.

Current Regulatory Liabilities

As of December 31, 2006, the Utility had current regulatory liabilities of approximately $309 million, consisting primarily of electric transmission wheeling revenue refunds and the RRB regulatory liability. These amounts are included in Other Current Liabilities on the Consolidated Balance Sheets. The Utility had current regulatory liabilities of $157 million, primarily comprised of price risk management activities, at December 31, 2005.

REGULATORY BALANCING ACCOUNTS

The Utility's regulatory balancing accounts are used as a mechanism for the Utility to recover amounts incurred for certain costs, primarily commodity costs. Sales balancing accounts accumulate differences between revenues and the Utility's authorized revenue requirements. Cost balancing accounts accumulate differences between incurred costs and authorized revenue requirements. The Utility also obtained CPUC approval for balancing account treatment of variances between forecasted and actual commodity costs and volumes. This approval results in eliminating the earnings impact from any throughput and revenue variances from adopted forecast levels. Under-collections that are probable of recovery through regulated rates are recorded as regulatory balancing account assets. Over-collections that are probable of being credited to customers are recorded as regulatory balancing account liabilities.

The Utility's current regulatory balancing accounts accumulate balances until they are refunded to or received from the Utility's customers through authorized rate adjustments within the next 12 months. Regulatory balancing accounts that the Utility does not expect to collect or refund in the next 12 months are included in noncurrent regulatory assets and liabilities. The CPUC does not allow the Utility to offset regulatory balancing account assets against balancing account liabilities.

Regulatory Balancing Account Assets

	Balance at December 31,	
(in millions)	**2006**	2005
Electricity revenue and cost balancing accounts	**$501**	$568
Natural gas revenue and cost balancing accounts	**106**	159
Total	**$607**	$727

Regulatory Balancing Account Liabilities

	Balance at December 31,	
(in millions)	**2006**	2005
Electricity revenue and cost balancing accounts	**$ 951**	$827
Natural gas revenue and cost balancing accounts	**79**	13
Total	**$1,030**	$840

During 2006, the under-collection in the Utility's electricity revenue and cost balancing account assets decreased from 2005 mainly due to regulatory decisions allowing the Utility to recover certain costs through customer rates. These amounts did not have authorized rate components in 2005, thus resulting in an under-collection. The increase in the over-collected position of the Utility's electricity revenue and cost balancing account liabilities between 2005 and 2006 was attributable to lower procurement costs as compared to forecasted procurement costs.

During 2006, the under-collection in the Utility's natural gas revenue and cost balancing account assets decreased and the over-collection in balancing account liabilities increased from 2005 due mainly to decreasing gas costs as compared to the approved revenue requirements.

NOTE 4: DEBT

LONG-TERM DEBT

The following table summarizes PG&E Corporation's and the Utility's long-term debt:

(in millions)	December 31, 2006	2005
PG&E Corporation		
Convertible subordinated notes, 9.50%, due 2010	$ 280	$ 280
Less: current portion	(280)	–
Long-term debt, net of current portion	–	280
Utility		
Senior notes/first mortgage bonds(1):		
3.60% to 6.05% bonds, due 2009–2034	5,100	5,100
Unamortized discount, net of premium	(16)	(17)
Total senior notes/first mortgage bonds	5,084	5,083
Pollution control bond loan agreements, variable rates(2), due 2026(3)	614	614
Pollution control bond loan agreement, 5.35%, due 2016	200	200
Pollution control bond loan agreements, 3.50%, due 2023(4)	345	345
Pollution control bond loan agreements, variable rates(5), due 2016–2026	454	454
Other	1	2
Less: current portion	(1)	(2)
Long-term debt, net of current portion	6,697	6,696
Total consolidated long-term debt, net of current portion	**$6,697**	**$6,976**

(1) When originally issued, these debt instruments were denominated as first mortgage bonds and were secured by a lien, subject to permitted exceptions, on substantially all of the Utility's real property and certain tangible personal property related to its facilities. The indenture under which the first mortgage bonds were issued provided for release of the lien in certain circumstances subject to certain conditions. The release occurred in April 2005 and the remaining bonds were redesignated as senior notes.

(2) At December 31, 2006, interest rates on these loans ranged from 3.80% to 3.92%.

(3) These bonds are supported by $620 million of letters of credit which expire on April 22, 2010. Although the stated maturity date is 2026, the bonds will remain outstanding only if the Utility extends or replaces the letters of credit.

(4) These bonds are subject to a mandatory tender for purchase on June 1, 2007 and the interest rates for these bonds are set until that date.

(5) At December 31, 2006, interest rates on these loans ranged from 3.25% to 3.70%.

PG&E CORPORATION

Convertible Subordinated Notes

At December 31, 2006, PG&E Corporation had outstanding $280 million of 9.5% Convertible Subordinated Notes that are scheduled to mature on June 30, 2010, or Convertible Subordinated Notes. These Convertible Subordinated Notes may be converted (at the option of the holder) at any time prior to maturity into 18,558,655 shares of common stock of PG&E Corporation, at a conversion price of approximately $15.09 per share. The conversion price is subject to adjustment should a significant change occur in the number of PG&E Corporation's shares of common stock outstanding. In addition, holders of the Convertible Subordinated Notes are entitled to receive "pass-through dividends" determined by multiplying the cash dividend paid by PG&E Corporation per share of common stock by a number equal to the principal amount of the Convertible Subordinated Notes divided by the conversion price. In connection with common stock dividends paid to holders of PG&E Corporation common stock in 2006, PG&E Corporation paid approximately $24 million of "pass-through dividends" to the holders of Convertible Subordinated Notes. The holders have a one-time right to require PG&E Corporation to repurchase the Convertible Subordinated Notes on June 30, 2007, at a purchase price equal to the principal amount plus accrued and unpaid interest (including liquidated damages and unpaid "pass-through dividends," if any).

Accordingly, PG&E Corporation has classified the Convertible Subordinated Notes in Current Liabilities – Long-term debt, in the accompanying Consolidated Balance Sheet as of December 31, 2006.

In accordance with SFAS No. 133, the dividend participation rights component of the Convertible Subordinated Notes is considered to be an embedded derivative instrument and, therefore, must be bifurcated from the Convertible Subordinated Notes and recorded at fair value in PG&E Corporation's Consolidated Financial Statements. Changes in the fair value are recognized in PG&E Corporation's Consolidated Statements of Income as a non-operating expense or income (included in Other income (expense), net). At December 31, 2006 and 2005, the total estimated fair value of the dividend participation rights component, on a pre-tax basis, was approximately $79 million and $92 million, respectively, of which $23 million and $22 million, respectively, was classified as a current liability (in Current Liabilities – Other) and $56 million and $70 million, respectively, was classified as a noncurrent liability (in Noncurrent Liabilities – Other).

UTILITY

Senior Notes

The Senior Notes are unsecured general obligation ranking equal with the Utility's other senior unsecured debt. Under the indenture of the Senior Notes, the Utility has agreed that it will not incur secured debt (except for (1) debt secured by specified liens, and (2) secured debt in an amount not exceeding 10% of the Utility's net tangible assets, as defined in the indenture) unless the Utility provided that the Senior Notes will be equally and ratably secured with the new secured debt.

At December 31, 2006, there were $5.1 billion of Senior Notes outstanding.

Pollution Control Bonds

The California Pollution Control Financing Authority and the California Infrastructure and Economic Development Bank, or CIEDB, issued various series of tax-exempt pollution control bonds for the benefit of the Utility. At December 31, 2006, pollution control bonds in the aggregate principal amount of $1.6 billion were outstanding. Under the pollution control bond loan agreements, the Utility is obligated to pay on the due dates an amount equal to the principal, premium, if any, and interest on these bonds to the trustees for these bonds.

All of the pollution control bonds financed or refinanced pollution control facilities at the Utility's Geysers geothermal power plant, or the Geysers Project, or at the Utility's Diablo Canyon nuclear power plant, or Diablo Canyon. In 1999, the Utility sold the Geysers Project to Geysers Power Company LLC, a subsidiary of Calpine Corporation. The Geysers Project purchase and sale agreements state that Geysers Power Company LLC will use the facilities solely as pollution control facilities within the meaning of Section 103(b)(4)(F) of the Internal Revenue Code and associated regulations, or the Code. On February 3, 2006, Geysers Power Company LLC filed for reorganization under Chapter 11. The Utility believes that the Geysers Project will continue to meet the use requirements of the Code.

In order to enhance the credit ratings of these pollution control bonds, the Utility has obtained credit support from banks and insurance companies such that, in the event that the Utility does not pay debt servicing costs, the banks or insurance companies will pay the debt servicing costs. The following table summarizes these credit supports:

(in millions)			At December 31, 2006
Utility			
Facility[1]	Series	Termination Date	Commitment
Pollution control bond bank reimbursement agreements	96 C, E, F, 97 B	April 2010	$ 620
Pollution control bond – bond insurance reimbursement agreements	96A	December 2016[2]	200
Pollution control bond – bond insurance reimbursement agreements	2004 A–D	December 2023[2]	345
Pollution control bond – bond insurance reimbursement agreements	2005 A–G	2016–2026[2]	454
Total credit support			$1,619

(1) Off-balance sheet commitments.
(2) Principal and debt service insured by the bond insurance company.

On April 20, 2005, the Utility repaid $454 million under pollution control bond loan agreements that the Utility had entered into in April 2004. The repayment of these reimbursement agreements was made through $454 million of borrowings under the Utility's working capital facility (see further discussion of the working capital facility below). Subsequently, on May 24, 2005, the Utility entered into seven loan agreements with the CIEDB to issue seven series of tax-exempt pollution control bonds, or PC Bonds Series A-G, totaling $454 million. These series are in auction modes where interest rates are set among investors who submit bids to buy, sell, or hold securities at desired rates. Four series of the bonds (Series A-D) have auctions every 35 days and three series (Series E-G) have auctions every seven days. Maturities on the bonds range from 2016 to 2026. The Utility repaid borrowings under the working capital facility using the proceeds from the tax-exempt PC Bonds Series A-G.

In April and November 2005, the Utility amended the four bank reimbursement agreements totaling $620 million, and relating to letters of credit issued to provide the credit support for the PC Bonds referred to above, to reduce pricing and generally conforming the covenants and events of default to those in the Utility's working capital facility (described below), as well as extend their terms to April 22, 2010.

Repayment Schedule

At December 31, 2006, PG&E Corporation's and the Utility's combined aggregate principal repayment amounts of long-term debt are reflected in the table below:

(in millions, except interest rates)	2007	2008	2009	2010	2011	Thereafter	Total
Long-term debt:							
PG&E Corporation							
Average fixed interest rate	9.50%	–	–	–	–	–	9.50%
Fixed rate obligations	$ 280	$ –	$ –	$ –	$ –	$ –	$ 280
Utility							
Average fixed interest rate	–	–	3.60%	–	4.20%	5.55%	5.22%
Fixed rate obligations	$ –	$ –	$ 600	$ –	$ 500	$4,529	$5,629
Variable interest rate as of December 31, 2006	–	–	–	3.88%	–	3.59%	3.76%
Variable rate obligations	$ –	$ –	$ –	$ 614[1]	$ –	$ 454	$1,068
Other	$ 1	$ –	$ –	$ –	$ –	$ –	$ 1
Less: current portion	(281)	–	–	–	–	–	(281)
Total consolidated long-term debt	$ –	$ –	$ 600	$ 614	$ 500	$4,983	$6,697

(1) The $614 million pollution control bonds, due in 2026, are backed by letters of credit which expire on April 22, 2010. The bonds will be subject to a mandatory redemption unless the letters of credit are extended or replaced. Accordingly, the bonds have been classified for repayment purposes in 2010.

CREDIT FACILITIES AND SHORT-TERM BORROWINGS

The following table summarizes PG&E Corporation's and the Utility's short-term borrowings and outstanding credit facilities at December 31, 2006:

(in millions) At December 31, 2006

Authorized Borrower	Facility	Termination Date	Facility Limit	Letters of Credit Outstanding	Cash Borrowings	Commercial Paper Backup	Availability
PG&E Corporation	Senior credit facility	December 2009	$ 200[1]	$ –	$ –	$ –	$ 200
Utility	Accounts receivable financing	March 2007	650	–	300	–	350
Utility	Working capital facility	April 2010	1,350[2]	144	–	460	746
Total credit facilities			$2,200	$144	$300	$460	$1,296

(1) Includes $50 million sublimit for letters of credit and $100 million sublimit for swingline loans, which are made available on a same-day basis and repayable in full within 30 days.

(2) Includes a $950 million sublimit for letters of credit and $100 million sublimit for swingline loans, which are made available on a same-day basis and repayable in full within 30 days.

PG&E CORPORATION

Senior Credit Facility

PG&E Corporation has a $200 million revolving senior unsecured credit facility, or senior credit facility, with a syndicate of lenders that, as amended, extends to December 10, 2009. Borrowings under the senior credit facility and letters of credit may be used for working capital and other corporate purposes. PG&E Corporation can, at any time, repay amounts outstanding in whole or in part. At PG&E Corporation's request and at the sole discretion of each lender, the senior credit facility may be extended for additional periods. PG&E Corporation has the right to increase, in one or more requests given no more than once a year, the aggregate facility by up to $100 million provided certain conditions are met. At December 31, 2006, PG&E Corporation had not undertaken any borrowings or issued any letters of credit under the senior credit facility.

The fees and interest rates PG&E Corporation pays under the senior credit facility vary depending on the Utility's unsecured debt ratings issued by Standard & Poor's Ratings Service, or S&P, and Moody's Investors Service, or Moody's. Interest is payable quarterly in arrears, or earlier for loans with shorter interest periods. In addition, a facility fee based on the aggregate facility and a utilization fee based on the average daily amount outstanding under the senior credit facility are payable quarterly in arrears by PG&E Corporation.

In addition, PG&E Corporation pays a fee for each letter of credit outstanding under the senior credit facility and a fronting fee to the issuer of a letter of credit. Interest, fronting fees, normal lender costs of issuing and negotiating letter of credit arrangements are payable quarterly in arrears.

The senior credit facility includes usual and customary covenants for credit facilities of this type, including covenants limiting liens, mergers, sales of all or substantially all of PG&E Corporation's assets and other fundamental changes. In general, the covenants, representations and events of default mirror those in the Utility's working capital facility, discussed below. In addition, the senior credit facility also requires that PG&E Corporation maintain a ratio of total consolidated debt to total consolidated capitalization of at most 65% and that PG&E Corporation own, directly or indirectly, at least 80% of the common stock and at least 70% of the voting securities of the Utility.

UTILITY

Accounts Receivable Financing

On March 5, 2004, the Utility entered into certain agreements providing for the continuous sale of a portion of the Utility's accounts receivable to PG&E Accounts Receivable Company, LLC, or PG&E ARC, a limited liability company wholly owned by the Utility. In turn, PG&E ARC sells interests in its accounts receivable to commercial paper conduits or banks. PG&E ARC may obtain up to $650 million of financing under such agreements. The borrowings under this facility bear interest at commercial paper rates and a fixed margin based on the Utility's credit ratings. Interest on the facility is payable monthly. At December 31, 2006, the average interest rate on borrowings on the accounts receivable facility was 5.36%. The maximum amount available for borrowing under this facility changes based upon the amount of eligible receivables, concentration of eligible receivables and other factors. The accounts receivable facility will terminate on March 5, 2007. The Utility is seeking an increase to its bank credit facilities in light of the impending expiration of the accounts receivable facility. There were $300 million of borrowings outstanding under the accounts receivable facility at December 31, 2006 and $260 million of borrowings outstanding at December 31, 2005.

Although PG&E ARC is a wholly owned consolidated subsidiary of the Utility, PG&E ARC is legally separate from the Utility. The assets of PG&E ARC (including the accounts receivable) are not available to creditors of the Utility or PG&E Corporation, and the accounts receivable are not legally assets of the Utility or PG&E Corporation. For the purposes of financial reporting, the credit facility is accounted for as a secured financing.

The accounts receivable facility includes a covenant from the Utility requiring it to maintain, as of the end of each fiscal quarter ending after the effective date of the Utility's plan of reorganization, a debt to capitalization ratio of at most 65%.

Working Capital Facility

The Utility has a $1.35 billion credit facility, or the working capital facility. Loans under the working capital facility are used primarily to cover operating expenses and seasonal fluctuations in cash flows and were used for bridge financing in connection with the repayment of the pollution control bond loan agreements discussed above. Letters of credit under the working capital facility are used primarily to provide credit enhancements to counterparties for natural gas and energy procurement transactions.

Subject to obtaining any required regulatory approvals and commitments from existing or new lenders and satisfaction of other specified conditions, the Utility may increase, in one or more requests given not more frequently than once a calendar year, the aggregate lenders' commitments under the working capital facility by up to $500 million or, in the event that the Utility's $650 million accounts receivable facility terminates or expires, by up to $850 million, in the aggregate for all such increases.

The working capital facility expires on April 8, 2010. At the Utility's request and at the sole discretion of each lender, the facility may be extended for additional periods. The Utility has the right to replace any lender who does not agree to an extension.

The fees and interest rates the Utility pays under the working capital facility vary depending on the Utility's unsecured debt rating by S&P and Moody's. The Utility is also required to pay a facility fee based on the total amount of working capital facility (regardless of the usage) and a utilization fee based on the average daily amount outstanding under the working capital facility. Interest is payable quarterly in arrears, or earlier for loans with shorter interest periods.

The working capital facility includes usual and customary covenants for credit facilities of this type, including covenants limiting liens to those permitted under the Senior Notes' indenture, mergers, sales of all or substantially all of the Utility's assets and other fundamental changes. In addition, the working capital facility also requires that the Utility maintain a debt to capitalization ratio of at most 65% as of the end of each fiscal quarter.

At December 31, 2006, there were no loans outstanding and approximately $144 million of letters of credit outstanding under the $1.35 billion working capital facility. Additionally, the working capital facility supports the $460 million of outstanding commercial paper discussed below.

Commercial Paper Program

On January 10, 2006, the Utility entered into various agreements to establish the terms and procedures for the issuance of up to $1 billion of unsecured commercial paper by the Utility for general corporate purposes. The commercial paper is not registered under the Securities Act of 1933 or applicable state securities laws and may not be offered or sold in the United States absent registration under the Securities Act of 1933 or applicable state exemption from registration requirements. The commercial paper may have maturities up to 365 days and ranks equally with the Utility's unsubordinated and unsecured indebtedness. At December 31, 2006, the Utility had $460 million, including amortization of a $2 million discount, of commercial paper outstanding at an average yield of approximately 5.44%. Commercial paper notes are sold at an interest rate dictated by the market at the time of issuance.

NOTE 5: RATE REDUCTION BONDS

In December 1997, PG&E Funding, LLC, a limited liability corporation wholly owned by and consolidated by the Utility, issued $2.9 billion of RRBs. The proceeds of the RRBs were used by PG&E Funding, LLC to purchase from the Utility the right, known as "transition property," to be paid a specified amount from a non-bypassable charge levied on residential and small commercial customers (Fixed Transition Amount, or FTA, charges). FTA charges are authorized by the CPUC under state legislation and will be paid by residential and small commercial customers until the RRBs are fully retired. Under the terms of a transition property servicing agreement, FTA charges are collected by the Utility and remitted to PG&E Funding, LLC for the payment of the bond principal, interest and miscellaneous expenses associated with the bonds.

The total amount of RRB principal outstanding was $290 million at December 31, 2006 and $580 million at December 31, 2005. The scheduled quarterly principal payments on the RRBs for 2007 total $290 million at a 6.48% interest rate. The RRBs are scheduled to mature on December 26, 2007.

While PG&E Funding, LLC is a wholly owned consolidated subsidiary of the Utility, it is legally separate from the Utility. The assets of PG&E Funding, LLC are not available to creditors of the Utility or PG&E Corporation, and the transition property is not legally an asset of the Utility or PG&E Corporation. The RRBs are secured solely by the transition property and there is no recourse to the Utility or PG&E Corporation.

NOTE 6: ENERGY RECOVERY BONDS

In furtherance of the Chapter 11 Settlement Agreement, PG&E Energy Recovery Funding, LLC, or PERF, a wholly owned consolidated subsidiary of the Utility, issued two separate series of ERBs in the aggregate amount of $2.7 billion in 2005 supported by a dedicated rate component, or DRC. The proceeds of the ERBs were used by PERF to purchase from the Utility the right, known as "recovery property," to be paid a specified amount from a DRC. DRC charges are authorized by the CPUC under state legislation and will be paid by the Utility's electricity customers until the ERBs are fully retired. Under the terms of a recovery property servicing agreement, DRC charges are collected by the Utility and remitted to PERF for payment of the bond principal, interest and miscellaneous expenses associated with the bonds.

The first series of ERBs issued on February 10, 2005 included five classes aggregating approximately $1.9 billion principal amount with scheduled maturities ranging from September 25, 2006 to December 25, 2012. Interest rates on the five classes range from 3.32% for the earliest maturing class, which matured on September 25, 2006, to 4.47% for the latest maturing class. The proceeds of the first series of ERBs were paid by PERF to the Utility and were used by the Utility to refinance the remaining unamortized after-tax balance of the settlement regulatory asset. The second series of ERBs, issued on November 9, 2005, included three classes aggregating approximately $844 million principal amount, with scheduled maturities ranging from June 25, 2009 to December 25, 2012. Interest rates on the three classes range from 4.85% for the earliest maturing class to 5.12% for the latest maturing class. The proceeds of the second series of ERBs were paid by PERF to the Utility to pre-fund the Utility's tax liability that will be due as the Utility collects the DRC related to the first series of ERBs.

The total amount of ERB principal outstanding was $2.3 billion at December 31, 2006 and $2.6 billion at December 31, 2005. The scheduled repayments for ERBs are reflected in the table below:

(in millions)	2007	2008	2009	2010	2011	Thereafter	Total
Utility							
Average fixed interest rate	4.19%	4.19%	4.36%	4.49%	4.61%	4.64%	4.43%
Energy recovery bonds	$ 340	$ 354	$ 369	$ 386	$ 424	$ 403	$2,276

While PERF is a wholly owned consolidated subsidiary of the Utility, PERF is legally separate from the Utility. The assets of PERF (including the recovery property) are not available to creditors of the Utility or PG&E Corporation, and the recovery property is not legally an asset of the Utility or PG&E Corporation.

NOTE 7: DISCONTINUED OPERATIONS

NEGT, formerly known as PG&E National Energy Group, Inc., was incorporated on December 18, 1998, as a wholly owned subsidiary of PG&E Corporation. NEGT filed a voluntary petition for relief under Chapter 11 on July 8, 2003, and as a result, PG&E Corporation no longer consolidated NEGT and its subsidiaries in its Consolidated Financial Statements. Consolidation is generally required under GAAP for entities owning more than 50% of the outstanding voting stock of an investee, unless control is not held by the majority owner. Legal reorganization and bankruptcy can preclude consolidation in instances where control rests with an entity other than the majority owner. Because PG&E Corporation's representatives on the NEGT Board of Directors resigned on July 7, 2003, and were replaced with Board members who were not affiliated with PG&E Corporation, PG&E Corporation no longer retained significant influence over the ongoing operations of NEGT at the filing of the petition.

Accordingly, PG&E Corporation's net negative investment in NEGT of approximately $1.2 billion was reflected as a single amount, under the cost method, within the December 31, 2003 Consolidated Balance Sheet of PG&E Corporation. This negative investment represents the losses of NEGT recognized by PG&E Corporation in excess of its investment in and advances to NEGT.

PG&E Corporation's equity ownership in NEGT was cancelled on October 29, 2004, the date when NEGT's plan of reorganization became effective. At that date, PG&E Corporation reversed its negative investment in NEGT and also reversed net deferred income tax assets of approximately $428 million and a charge of approximately $120 million ($77 million, after tax) in accumulated other comprehensive loss, related to NEGT. The resulting net gain has been offset by the $30 million payment made by PG&E Corporation to NEGT pursuant to the parties' settlement of certain tax-related litigation and other adjustments to NEGT-related liabilities. A summary of the effect on the year ended December 31, 2004 earnings from discontinued operations is as follows:

(in millions)	
Negative investment in NEGT	$1,208
Accumulated other comprehensive loss	(120)
Cash paid pursuant to settlement of tax related litigation	(30)
Tax effect	(374)
Gain on disposal of NEGT, net of tax	$ 684

During the third quarter of 2005, PG&E Corporation received additional information from NEGT regarding income to be included in PG&E Corporation's 2004 federal income tax return. This information was incorporated in the 2004 tax return, which was filed with the Internal Revenue Service, or IRS, in September 2005. As a result, the 2004 federal income tax liability was reduced by approximately $19 million. In addition, NEGT provided additional information with respect to amounts previously included in PG&E Corporation's 2003 federal income tax return. This change resulted in PG&E Corporation's 2003 federal income tax liability increasing by approximately $6 million. These two adjustments, netting to $13 million, were recognized in income from discontinued operations in 2005.

At December 31, 2005, PG&E Corporation's Consolidated Balance Sheet included approximately $89 million of current income taxes payable and approximately $27 million of other net liabilities related to NEGT. At December 31, 2006, PG&E Corporation's Consolidated Balance Sheet included approximately $89 million of current income taxes payable and approximately $26 million of other net liabilities related to NEGT. Until PG&E Corporation reaches final settlement of these obligations, it will continue to disclose fluctuations in these estimated liabilities in discontinued operations. PG&E Corporation ceased including NEGT and its subsidiaries in its consolidated income tax returns beginning October 29, 2004.

NOTE 8: COMMON STOCK

PG&E CORPORATION

PG&E Corporation has authorized 800 million shares of no-par common stock, of which 374,181,059 shares were issued and outstanding at December 31, 2006 and 368,268,502 were issued and outstanding at December 31, 2005. A wholly owned subsidiary of PG&E Corporation, Elm Power Corporation, holds 24,665,500 of the outstanding shares.

Of the 374,181,059 shares issued and outstanding at December 31, 2006, 1,377,538 shares have been granted as restricted stock as share-based compensation awarded under the PG&E Corporation Long-Term Incentive Plan, or 2006 LTIP (see Note 14 for further discussion).

In 2002, PG&E Corporation issued warrants to purchase 5,066,931 shares of its common stock at an exercise price of $0.01 per share. During 2006, 51,890 shares of PG&E Corporation common stock were issued upon exercise of the warrants. As of December 31, 2006, all warrants issued had been exercised.

Stock Repurchases

During 2004, 1,863,600 shares of PG&E Corporation common stock were repurchased for an aggregate purchase price of approximately $60 million. Of this amount, 850,000 shares were purchased at a cost of approximately $28 million and are held by Elm Power Corporation.

On December 15, 2004, PG&E Corporation entered into an accelerated share repurchase agreement, or ASR, with Goldman Sachs & Co., Inc., or GS&Co., under which PG&E Corporation repurchased 9,769,600 shares of its outstanding common stock for an aggregate purchase price of approximately $332 million, including a $14 million price adjustment paid on February 22, 2005. This adjustment was based on the daily volume weighted average market price, or VWAP, of PG&E Corporation common stock over the term of the arrangement.

In 2005, PG&E Corporation repurchased a total of 61,139,700 shares of its outstanding common stock through two ASRs with GS&Co. for an aggregate purchase price of $2.2 billion, including price adjustments based on the VWAP and other amounts. In 2006, PG&E Corporation paid GS&Co. $114 million in additional payments (net of amounts payable by GS&Co. to PG&E Corporation) to satisfy obligations under the last of these ASRs entered into in November 2005. PG&E Corporation's payments reduced common shareholders' equity. PG&E Corporation has no remaining obligation under the November 2005 ASR.

To reflect the potential dilution that existed while the obligations related to the ASRs were outstanding, PG&E Corporation treated approximately 1 million additional shares of PG&E Corporation common stock as outstanding for purposes of calculating diluted EPS for 2006 (see Note 10 below).

UTILITY

The Utility is authorized to issue 800 million shares of its $5 par value common stock, of which 279,624,823 shares were issued and outstanding as of December 31, 2006 and 2005. PG&E Holdings, LLC, a wholly owned subsidiary of the Utility, holds 19,481,213 of the outstanding shares. PG&E Corporation and PG&E Holdings, LLC hold all of the Utility's outstanding common stock.

The Utility may pay common stock dividends and repurchase its common stock, provided cumulative preferred dividends on its preferred stock are paid. As further discussed in Note 9, on the effective date of the Utility's plan of reorganization, the Utility paid cumulative preferred dividends and preferred sinking fund payments related to 2004, 2003 and 2002.

DIVIDENDS

PG&E Corporation and the Utility did not declare or pay a dividend during the Utility's Chapter 11 proceeding as the Utility was prohibited from paying any common or preferred stock dividends without Bankruptcy Court approval and certain covenants in the indenture related to senior secured notes of PG&E Corporation during that period restricted the circumstances in which such a dividend could be declared or paid. With the Utility's emergence from Chapter 11 on April 12, 2004, the Utility resumed the payment of preferred stock dividends. The Utility reinstated the payment of a regular quarterly common stock dividend to PG&E Corporation in January 2005, upon the achievement of the 52% equity ratio targeted in the Chapter 11 Settlement Agreement.

During 2005, the Utility paid cash dividends of $476 million on the Utility's common stock. Approximately $445 million in dividends was paid to PG&E Corporation and the remainder was paid to PG&E Holdings, LLC, a wholly owned subsidiary of the Utility. On April 15, July 15 and October 15, 2005, PG&E Corporation paid a quarterly common stock dividend of $0.30 per share, totaling approximately $356 million, including approximately $22 million of common stock dividends paid to Elm Power Corporation, a wholly owned subsidiary of PG&E Corporation.

During 2006, the Utility paid cash dividends of $494 million on the Utility's common stock. Approximately $460 million in common stock dividends were paid to PG&E Corporation and the remaining amount was paid to PG&E Holdings, LLC. PG&E Holdings, LLC held approximately 7% of the Utility's common stock as of February 20, 2007.

On January 16, April 15, July 15 and October 15, 2006, PG&E Corporation paid common stock dividends of $0.33 per share, totaling approximately $489 million, including approximately $33 million of common stock dividends paid to Elm Power Corporation, a wholly owned subsidiary of PG&E Corporation that held approximately 7% of PG&E Corporation's common stock as of February 20, 2007.

On December 20, 2006, the Board of Directors of PG&E Corporation declared a dividend of $0.33 per share, totaling approximately $123 million that was payable to shareholders of record on December 29, 2006 on January 15, 2007. PG&E Corporation and the Utility record common stock dividends declared to Reinvested Earnings.

NOTE 9: PREFERRED STOCK

PG&E Corporation has authorized 85 million shares of preferred stock, which may be issued as redeemable or nonredeemable preferred stock. No preferred stock of PG&E Corporation has been issued.

UTILITY

The Utility has authorized 75 million shares of $25 par value preferred stock and 10 million shares of $100 par value preferred stock. The Utility specifies that 5,784,825 shares of the $25 par value preferred stock authorized are designated as nonredeemable preferred stock without mandatory redemption provisions. The remainder of the 75 million shares of $25 par value preferred stock and the 10 million shares of $100 par value preferred stock may be issued as redeemable or nonredeemable preferred stock.

At December 31, 2006 and 2005, the Utility had issued and outstanding 5,784,825 shares of nonredeemable $25 par value preferred stock without mandatory redemption provisions. Holders of the Utility's 5.0%, 5.5% and 6.0% series of nonredeemable $25 par value preferred stock have rights to annual dividends ranging from $1.25 to $1.50 per share.

At December 31, 2006 and 2005, the Utility had issued and outstanding 4,534,958 shares of redeemable $25 par value preferred stock without mandatory redemption provisions. The Utility's redeemable $25 par value preferred stock is subject to redemption at the Utility's option, in whole or in part, if the Utility pays the specified redemption price plus accumulated and unpaid dividends through the redemption date. At December 31, 2006, annual dividends ranged from $1.09 to $1.25 per share and redemption prices ranged from $25.75 to $27.25 per share.

The last of the Utility's redeemable $25 par value preferred stock with mandatory redemption provisions was redeemed on May 31, 2005. Currently, the Utility does not have any shares of the $100 par value preferred stock with or without mandatory redemption provisions outstanding.

Dividends on all Utility preferred stock are cumulative. All shares of preferred stock have voting rights and an equal preference in dividend and liquidation rights. Because it could not pay dividends during its Chapter 11 proceeding, the Utility paid approximately $82 million in dividends on Utility preferred stock and preferred sinking fund payments on the effective date of the Utility's plan of reorganization. Throughout the remainder of 2004, the Utility paid dividends of approximately $19 million. During the year ended December 31, 2005, the Utility paid approximately $16 million of dividends on preferred stock without mandatory redemption provisions and approximately $5 million of dividends on preferred stock with mandatory redemption provisions. During the year ended December 31, 2006, the Utility paid approximately $14 million of dividends on preferred stock without mandatory redemption provisions. On February 21, 2007, the Board of Directors of the Utility declared a cash dividend on various series of its preferred stock, payable on May 5, 2007, to shareholders of record on April 30, 2007. Upon liquidation or dissolution of the Utility, holders of preferred stock would be entitled to the par value of such shares plus all accumulated and unpaid dividends, as specified for the class and series.

On June 15, 2005, the Utility's Board of Directors authorized the redemption of all of the outstanding shares of the Utility's 7.04% Redeemable First Preferred Stock totaling approximately $36 million aggregate par value plus approximately $1 million related to a $0.70 per share redemption premium. This issue was fully redeemed on August 31, 2005. In addition to the $25 per share redemption price, holders of the 7.04% Redeemable First Preferred Stock received an amount equal to all accumulated and unpaid dividends through August 31, 2005 on such shares totaling approximately $211,000.

NOTE 10: EARNINGS PER SHARE

EPS is calculated, utilizing the "two-class" method, by dividing the sum of distributed earnings to common shareholders and undistributed earnings allocated to common shareholders by the weighted average number of common shares outstanding during the period. In applying the "two-class" method, undistributed earnings are allocated to both common shares and participating securities. Holders of PG&E Corporation's Convertible Subordinated Notes are entitled to receive (non-cumulative) dividend payments prior to exercising the conversion option. As a result of this feature, the Convertible Subordinated Notes meet the criteria of a participating security. All PG&E Corporation's participating securities participate on a 1:1 basis in dividends with common shareholders.

The following is a reconciliation of PG&E Corporation's net income and weighted average common shares outstanding for calculating basic and diluted net income per share:

(in millions, except per share amounts)	Year ended December 31, 2006	2005	2004
Net Income	$ 991	$ 917	$4,504
Less: distributed earnings to common shareholders	460	449	–
Undistributed earnings	531	468	4,504
Less: undistributed earnings from discontinued operations	–	13	684
Undistributed earnings from continuing operations	$ 531	$ 455	$3,820
Common shareholders earnings			
Basic			
Distributed earnings to common shareholders	$ 460	$ 449	$ –
Undistributed earnings allocated to common shareholders – continuing operations	503	433	3,646
Undistributed earnings allocated to common shareholders – discontinued operations	–	12	653
Total common shareholders earnings, basic	$ 963	$ 894	$4,299
Diluted			
Distributed earnings to common shareholders	$ 460	$ 449	$ –
Undistributed earnings allocated to common shareholders – continuing operations	504	433	3,650
Undistributed earnings allocated to common shareholders – discontinued operations	–	12	653
Total common shareholders earnings, diluted	$ 964	$ 894	$4,303
Weighted average common shares outstanding, basic	346	372	398
9.50% Convertible Subordinated Notes	19	19	19
Weighted average common shares outstanding and participating securities, basic	365	391	417
Weighted average common shares outstanding, basic	346	372	398
Employee share-based compensation and accelerated share repurchases(1)	3	6	7
PG&E Corporation warrants	–	–	2
Weighted average common shares outstanding, diluted	349	378	407
9.50% Convertible Subordinated Notes	19	19	19
Weighted average common shares outstanding and participating securities, diluted	368	397	426
Net earnings per common share, basic			
Distributed earnings, basic(2)	$1.33	$1.21	$ –
Undistributed earnings – continuing operations, basic	1.45	1.16	9.16
Undistributed earnings – discontinued operations, basic	–	0.03	1.64
Total	$2.78	$2.40	$10.80
Net earnings per common share, diluted			
Distributed earnings, diluted	$1.32	$1.19	$ –
Undistributed earnings – continuing operations, diluted	1.44	1.15	8.97
Undistributed earnings – discontinued operations, diluted	–	0.03	1.60
Total	$2.76	$2.37	$10.57

(1) Includes approximately 1 million, 2 million and 222,000 shares of PG&E Corporation common stock treated as outstanding in connection with accelerated share repurchases for the year ended December 31, 2006, December 31, 2005 and December 31, 2004, respectively. The remaining shares of approximately 2 million at December 31, 2006, 4 million at December 31, 2005 and 6.8 million at December 31, 2004, relate to share-based compensation and are deemed to be outstanding under SFAS No. 128 for the purpose of calculating EPS. See section of Note 2 entitled "Earnings Per Share."

(2) "Distributed earnings, basic" differs from actual per share amounts paid as dividends as the EPS computation under GAAP requires the use of the weighted average, rather than the actual number of shares outstanding.

PG&E Corporation stock options to purchase 28,500 and 7,046,710 shares were excluded from the computation of diluted EPS for 2005 and 2004, respectively, because the exercise prices of these options were greater than the average market price of PG&E Corporation common stock during these years. All PG&E Corporation stock options were included in the computation of diluted EPS for 2006 because the exercise price of these stock options was lower than the average market price of PG&E Corporation common stock during the year.

PG&E Corporation reflects the preferred dividends of subsidiaries as other expense for computation of both basic and diluted EPS.

NOTE 11: INCOME TAXES

The significant components of income tax (benefit) expense for continuing operations were:

	PG&E Corporation			Utility		
	Year ended December 31,					
(in millions)	2006	2005	2004	2006	2005	2004
Current:						
Federal	$ 743	$1,027	$ 121	$ 771	$1,048	$ 73
State	201	189	91	210	196	85
Deferred:						
Federal	(286)	(574)	1,877	(276)	(572)	2,000
State	(98)	(89)	384	(97)	(89)	410
Tax credits, net	(6)	(9)	(7)	(6)	(9)	(7)
Income tax expense	$ 554	$ 544	$2,466	$ 602	$ 574	$2,561

The following describes net deferred income tax liabilities:

	PG&E Corporation		Utility	
	Year ended December 31,			
(in millions)	2006	2005	2006	2005
Deferred income tax assets:				
Customer advances for construction	$ 806	$ 607	$ 806	$ 607
Reserve for damages	165	276	165	276
Environmental reserve	177	188	177	188
Compensation	131	90	95	66
Other	206	382	166	300
Total deferred income tax assets	$1,485	$1,543	$1,409	$1,437
Deferred income tax liabilities:				
Regulatory balancing accounts	$1,305	$1,719	$1,305	$1,719
Property related basis differences	2,778	2,694	2,778	2,694
Income tax regulatory asset	243	218	243	218
Unamortized loss on reacquired debt	120	128	120	128
Other	27	57	53	57
Total deferred income tax liabilities	$4,473	$4,816	$4,499	$4,816
Total net deferred income tax liabilities	$2,988	$3,273	$3,090	$3,379
Classification of net deferred income tax liabilities:				
Included in current liabilities	$ 148	$ 181	$ 118	$ 161
Included in noncurrent liabilities	2,840	3,092	2,972	3,218
Total net deferred income tax liabilities	$2,988	$3,273	$3,090	$3,379

The differences between income taxes and amounts calculated by applying the federal legal rate to income before income tax expense for continuing operations were:

	PG&E Corporation			Utility		
	Year ended December 31,					
	2006	2005	2004	2006	2005	2004
Federal statutory income tax rate	**35.0%**	35.0%	35.0%	**35.0%**	35.0%	35.0%
Increase (decrease) in income tax rate resulting from:						
State income tax (net of federal benefit)	**4.3**	4.5	4.6	**4.6**	4.7	4.7
Effect of regulatory treatment of depreciation differences	**0.6**	0.9	(0.5)	**0.6**	0.9	(0.4)
Tax credits, net	**(0.6)**	(1.0)	(0.2)	**(0.6)**	(1.0)	(0.2)
Other, net	**(3.4)**	(1.8)	0.3	**(1.6)**	(1.6)	0.2
Effective tax rate	**35.9%**	37.6%	39.2%	**38.0%**	38.0%	39.3%

The IRS has completed its audit of PG&E Corporation's 1997 and 1998 consolidated federal income tax returns and has assessed additional federal income taxes of approximately $87 million (including interest). PG&E Corporation filed protests contesting certain adjustments made by the IRS in that audit. In April 2006, PG&E Corporation and the IRS Appeals Office tentatively resolved the contested adjustments. However, another claim for refund, which PG&E Corporation filed with the IRS in December 2000, was transferred to the IRS Appeals Office in late 2006, and incorporated as part of the IRS's audit of PG&E Corporation's 1997 and 1998 consolidated federal income tax returns. This transfer will delay the final resolution of this audit. PG&E Corporation has not accrued a tax benefit regarding this claim.

The IRS is currently auditing PG&E Corporation's 2001 and 2002 consolidated federal income tax returns. The IRS is proposing to disallow a number of deductions claimed in PG&E Corporation's 2001 and 2002 tax returns. The largest of these deductions is a deduction for abandoned or worthless assets owned by NEGT. In addition, the IRS is proposing to disallow $104 million of synthetic fuel credits claimed in PG&E Corporation's 2001 and 2002 tax returns. If the IRS includes all of its proposed disallowances in its final Revenue Agent Report, the alleged tax deficiency would approximate $452 million. Of this alleged deficiency, approximately $104 million relates to the synthetic fuel credits and approximately $316 million is of a timing nature, which would be refunded to PG&E Corporation in the future. PG&E Corporation believes that it properly reported these transactions in its tax returns and will contest any IRS assessment. The IRS has extended its examination of PG&E Corporation's 2001 and 2002 tax returns to late 2007.

The IRS is also currently auditing PG&E Corporation's 2003 and 2004 consolidated federal income tax returns.

As of December 31, 2006, PG&E Corporation had accrued approximately $138 million for potential non-Utility tax obligations and interest related to outstanding audits, including the $89 million related to the proposed disallowance of deduction for abandoned or worthless assets owned by NEGT discussed above, and $49 million to cover potential tax obligations related to non-NEGT issues. The Utility had accrued approximately $52 million as of December 31, 2006, to cover potential tax obligations for outstanding audits. There have been no changes in the reserve balance since December 31, 2005.

After considering the above accruals, PG&E Corporation and the Utility do not expect the final resolution of the outstanding audits to have a material impact on their financial condition or results of operations.

PG&E Corporation recorded tax benefits of $19 million from capital losses carried forward and used in its 2005 federal and California income tax returns. PG&E Corporation has $229 million of remaining capital loss carry forwards from the disposition of its NEGT ownership interest in 2004, which, if not used by December 2009, will expire.

NOTE 12: DERIVATIVES AND HEDGING ACTIVITIES

The Utility enters into contracts to procure electricity, natural gas, nuclear fuel and firm electricity transmission rights. Except for contracts that meet the definition of normal purchases and sales, all derivative instruments including instruments designated as cash flow hedges of natural gas in the natural gas portfolios, are recorded at fair value and presented as price risk management assets and liabilities on the balance sheet. On PG&E Corporation's and the Utility's Consolidated Balance Sheets, price risk management activities appear as summarized below:

(in millions)	December 31, 2006	December 31, 2005
Current Assets – Prepaid expenses and other	$ 16	$140
Other Noncurrent Assets – Other	$ 37	$212
Current Liabilities – Other	$192	$ 2
Noncurrent Liabilities – Other	$ 50	$ –

Since these contracts are used within the regulatory framework, regulatory accounts are recorded to offset the costs and proceeds of these derivatives recognized in earnings and subsequently recovered in regulated rates charged to customers.

For cash flow hedges, the Utility recorded $8 million as Noncurrent Liabilities – Regulatory liabilities, $3 million as current regulatory liabilities (included in Current Liabilities – Other), and $25 million as current regulatory assets (included in Current Assets – Prepaid expenses and other) at December 31, 2006, compared to $59 million as Noncurrent Liabilities – Regulatory liabilities, $2 million as current regulatory liabilities (included in Current Liabilities – Other), and less than $1 million as Other Noncurrent Assets – Regulatory assets at December 31, 2005.

NOTE 13: NUCLEAR DECOMMISSIONING

The Utility's nuclear power facilities consist of two units at Diablo Canyon and the retired facility at Humboldt Bay Unit 3, or Humboldt Bay Unit 3. Nuclear decommissioning requires the safe removal of nuclear facilities from service and the reduction of residual radioactivity to a level that permits termination of the Nuclear Regulatory Commission, or NRC, license and release of the property for unrestricted use. For ratemaking purposes, the eventual decommissioning of Diablo Canyon Unit 1 is scheduled to begin in 2024 and to be completed in 2044. Decommissioning of Diablo Canyon Unit 2 is scheduled to begin in 2025 and to be completed in 2041, and decommissioning of Humboldt Bay Unit 3 is scheduled to begin in 2009 and to be completed in 2015.

As presented in the Utility's Nuclear Decommissioning Costs Triennial Proceeding, the estimated nuclear decommissioning cost for the Diablo Canyon Units 1 and 2 and Humboldt Bay Unit 3 is approximately $2.11 billion in 2006 dollars (or approximately $5.42 billion in future dollars). These estimates are based on the 2006 decommissioning cost studies, prepared in accordance with CPUC requirements. The Utility's revenue requirements for nuclear decommissioning costs are recovered from customers through a non-bypassable charge that will continue until those costs are fully recovered. The decommissioning cost estimates are based on the plant location and cost characteristics for the Utility's nuclear power plants. Actual decommissioning costs may vary from these estimates as a result of changes in assumptions such as decommissioning dates, regulatory requirements, technology, and costs of labor, materials and equipment.

The estimated nuclear decommissioning cost described above is used for regulatory purposes. Decommissioning costs recovered in rates are placed in nuclear decommissioning trusts. However, under GAAP requirements, the decommissioning cost estimate is calculated using a different method. In accordance with SFAS No. 143, the Utility adjusts its nuclear decommissioning obligation to reflect the fair value of decommissioning its nuclear power facilities. The Utility records the Utility's total nuclear decommissioning obligation as an asset retirement obligation on the Utility's Consolidated Balance Sheet. Decommissioning costs are recorded as a component of depreciation expense, with a corresponding credit to the asset retirement costs regulatory liability. The total nuclear decommissioning obligation accrued in accordance with GAAP was approximately $1.2 billion at December 31, 2006 and $1.3 billion at December 31, 2005. The primary difference between the Utility's estimated nuclear decommissioning obligation as recorded in accordance with GAAP and the estimate prepared in accordance with the CPUC requirements is that GAAP incorporates various potential settlement dates for the obligation and includes an estimated amount for third-party labor costs into the fair value calculation.

The Utility has three decommissioning trusts for its Diablo Canyon and Humboldt Bay Unit 3 nuclear facilities. The Utility has elected that two of these trusts be treated under the Internal Revenue Code as qualified trusts. If certain conditions are met, the Utility is allowed a deduction for the payments made to the qualified trusts. The qualified trusts are subject to a lower tax rate on income and capital gains, thereby increasing the trusts' after-tax returns. Among other requirements, to maintain the qualified trust status the IRS must approve the amount to be contributed to the qualified trusts for any taxable year. The remaining non-qualified trust is exclusively for decommissioning Humboldt Bay Unit 3. The Utility cannot deduct amounts contributed to the non-qualified trust until such decommissioning costs are actually incurred.

The funds in the decommissioning trusts, along with accumulated earnings, will be used exclusively for decommissioning and dismantling the Utility's nuclear facilities. The trusts maintain substantially all of their investments in debt and equity securities. The CPUC has authorized the qualified trust to invest a maximum of 50% of its funds in publicly-traded equity securities, of which up to 20% may be invested in publicly-traded non-U.S. equity securities. For the non-qualified trust, no more than 60% may be invested in publicly-traded equities, of which up to 20% may be invested in publicly-traded non-U.S. equity securities. The allocation of the trust funds is monitored monthly. To the extent that market movements cause the asset allocation to move outside these ranges, the investments are rebalanced toward the target allocation.

The Utility estimates after-tax annual earnings, including realized gains and losses, in the qualified trusts to be 5.9% and in the non-qualified trusts to be 4.8%. Trust earnings are included in the nuclear decommissioning trust assets and corresponding SFAS No. 143 regulatory liability. There is no impact on the Utility's earnings. Annual returns decrease in later years as higher portions of the trusts are dedicated to fixed income investments leading up to and during the entire course of decommissioning activities.

All earnings on the assets held in the trusts, net of authorized disbursements from the trusts and investment management and administrative fees, are reinvested. Amounts may not be released from the decommissioning trusts until authorized by the CPUC. At December 31, 2006, the Utility had accumulated nuclear decommissioning trust funds with an estimated fair value of approximately $1.9 billion, based on quoted market prices and net of deferred taxes on unrealized gains.

In general, investment securities are exposed to various risks, such as interest rate, credit and market volatility risks. Due to the level of risk associated with certain investment securities, it is reasonably possible that changes in the market values of investment securities could occur in the near term, and such changes could materially affect the trusts' fair value.

The Utility records unrealized gains and losses on investments held in the trusts in other comprehensive income in accordance with SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities." Realized gains and losses are recognized as additions or reductions to trust asset balances. The Utility, however, accounts for its nuclear decommissioning obligations in accordance with SFAS No. 71; therefore, both realized and unrealized gains and losses are ultimately recorded as regulatory assets or liabilities.

In 2006, total unrealized losses on the investments held in the trusts were $2 million. FASB Staff Position Nos. 115-1 and 124-1, "The Meaning of Other-Than-Temporary Impairment and Its Application to Certain Investments" state that an investment is impaired if the fair value of the investment is less than its cost and if the impairment is concluded to be other-than-temporary, an impairment loss is recognized. Since the day-to-day investing activities of the trusts are managed by external investment managers, the Utility is unable to conclude that the $2 million impairment is not other-than-temporary. As a result, an impairment loss was recognized and the Utility recorded a $2 million reduction to the nuclear decommissioning trusts assets and regulatory liability.

The following table provides a summary of the fair value, based on quoted market prices, of the investments held in the Utility's nuclear decommissioning trusts:

(in millions)	Maturity Date	Total Unrealized Gains	Total Unrealized Losses	Estimated Fair Value
Year ended December 31, 2006				
U.S. government and agency issues	2007–2036	**$ 34**	**$(1)**	**$ 814**
Municipal bonds and other	2007–2049	**7**	**(1)**	**258**
Equity securities		**644**	**—**	**991**
Total		**$685**	**$(2)**	**$2,063**
Year ended December 31, 2005				
U.S. government and agency issues	2006–2035	$ 42	$(2)	$ 763
Municipal bonds and other	2006–2036	10	(1)	192
Equity securities		534	—	871
Total		$586	$(3)	$1,826

The cost of debt and equity securities sold is determined by specific identification. The following table provides a summary of the activity for the debt and equity securities:

	Year ended December 31,		
(in millions)	**2006**	2005	2004
Proceeds received from sales of securities	**$1,087**	$2,918	$1,821
Gross realized gains on sales of securities held as available-for-sale	**55**	56	28
Gross realized losses on sales of securities held as available-for-sale	**(29)**	(14)	(22)

SPENT NUCLEAR FUEL STORAGE PROCEEDINGS

Under the Nuclear Waste Policy Act of 1982, the Department of Energy, or the DOE, is responsible for the transportation and permanent storage and disposal of spent nuclear fuel and high-level radioactive waste. The Utility has contracted with the DOE to provide for the disposal of these materials from Diablo Canyon. Under the contract, if the DOE completes a storage facility by 2010, the earliest that Diablo Canyon's spent fuel would be accepted for storage or disposal is thought to be 2018. Under current operating procedures, the Utility believes that the existing spent fuel pools (which include newly constructed temporary storage racks) have sufficient capacity to enable the Utility to operate Diablo Canyon until approximately 2010 for Unit 1 and 2011 for Unit 2. After receiving a permit from the NRC in March 2004, the Utility began building an on-site dry cask storage facility to store spent fuel through at least 2024. The Utility estimates it could complete the dry cask storage project in 2008. The NRC's March 2004 decision, however, was appealed by various parties, and the U.S. Court of Appeals for the Ninth Circuit issued a decision in 2006 that requires the NRC to consider the environmental consequences of a potential terrorist attack at Diablo Canyon as part of the NRC's supplemental assessment of the dry cask storage permit. The Utility may incur significant additional expenditures if the NRC decides that the Utility must change the design and construction of the dry cask storage facility. If the Utility is unable to complete the dry cask storage facility, or if construction is delayed beyond 2010, and if the Utility is otherwise unable to increase its on-site storage capacity, it is possible that the operation of Diablo Canyon may have to be curtailed or halted as early as 2010 with respect to Unit 1 and 2011 with respect to Unit 2 and until such time as additional spent fuel can be safely stored.

As a result of the DOE's failure to develop a permanent storage facility, the Utility has been required to incur substantial costs for planning and developing on-site storage options for spent nuclear fuel as described above at Diablo Canyon as well as at Humboldt Bay Unit 3. The Utility is seeking to recover these costs from the DOE on the basis that the DOE has breached its contractual obligation to move used nuclear fuel from Diablo Canyon and Humboldt Bay Unit 3 to a national repository beginning in 1998. Any amounts recovered from the DOE will be credited to customers. In October 2006, the U.S. Court of Federal Claims issued a decision awarding approximately $42.8 million of the $92 million incurred by the Utility through 2004. The Utility will seek recovery of costs incurred after 2004 in future lawsuits against the DOE. In January 2007, the Utility filed a notice of appeal of the U.S. Court of Federal Claims' decision in the U.S. Court of Appeals for the Federal Circuit seeking to increase the amount of the award and challenging the court's finding the Utility would have had to incur some of the costs for the on-site storage facilities even if the DOE had complied with the contract. If the court's decision is not overturned or modified on appeal, it is likely that the Utility will be unable to recover all of its future costs for on-site storage facilities from the DOE. However, reasonably incurred costs related to the on-site storage facilities are, in the case of Diablo Canyon, recoverable through rates and, in the case of Humboldt Bay Unit 3, recoverable through its decommissioning trust fund.

PG&E Corporation and the Utility are unable to predict the outcome of this appeal or the amount of any additional awards the Utility may receive.

NOTE 14: EMPLOYEE COMPENSATION PLANS

PG&E Corporation and its subsidiaries provide non-contributory defined benefit pension plans for certain employees and retirees, referred to collectively as pension benefits. PG&E Corporation and the Utility have elected that certain of the trusts underlying these plans be treated under the Internal Revenue Code as qualified trusts. If certain conditions are met, PG&E Corporation and the Utility can deduct payments made to the qualified trusts, subject to certain Internal Revenue Code limitations. PG&E Corporation and its subsidiaries also provide contributory defined benefit medical plans for certain retired employees and their eligible dependents, and non-contributory defined benefit life insurance plans for certain retired employees (referred to collectively as other benefits). The following schedules aggregate all PG&E Corporation's and the Utility's plans and are presented based on the sponsor of each plan. PG&E Corporation and its subsidiaries use a December 31 measurement date for all of their plans.

On December 31, 2006, PG&E Corporation and the Utility adopted SFAS No. 158. SFAS No. 158 requires the funded status of an entity's plans to be recognized on the balance sheet, eliminates the additional minimum liability and enhances related disclosure requirements. The funded status of a plan, as measured under SFAS No. 158, is the difference between the fair value of plan assets and the projected benefit obligation for a pension plan and the accumulated postretirement benefit obligation for other post-retirement benefit plans. SFAS No. 158 does not change the method of recording expense on the statement of income; therefore, the effects of adopting SFAS No. 158 did not have an impact on earnings or on cash flows.

Under SFAS No. 71, regulatory adjustments are recorded in the Consolidated Statements of Income and Consolidated Balance Sheets of the Utility to reflect the difference between Utility pension expense or income for accounting purposes and Utility pension expense or income for ratemaking, which is based on a funding approach. For 2006, only the portion of the pension contribution allocated to the gas transmission and storage business is not recoverable in rates. For 2006, the reduction in net income as a result of the Utility not being able to recover this portion in rates was approximately $5 million, net of tax. A regulatory adjustment is also recorded for the amounts that would otherwise be charged to accumulated other comprehensive income under SFAS No. 158 for the pension benefits. Since 1993, the CPUC has authorized the Utility to recover the costs associated with its other benefits based on the lesser of the SFAS No. 106 expense or the annual tax deductible contributions to the appropriate trusts. This recovery mechanism does not allow the Utility to record a regulatory adjustment for the SFAS No. 158 charge to accumulated other comprehensive income related to other benefits.

BENEFIT OBLIGATIONS

The following tables reconcile changes in aggregate projected benefit obligations for pension benefits and changes in the benefit obligation of other benefits during 2006 and 2005:

Pension Benefits

	PG&E Corporation		Utility	
(in millions)	2006	2005	2006	2005
Projected benefit obligation at January 1	**$9,249**	$8,557	**$9,211**	$8,551
Service cost for benefits earned	**236**	214	**233**	211
Interest cost	**511**	500	**509**	498
Plan amendments	**1**	(7)	**3**	(3)
Actuarial loss/(gain)	**(592)**	331	**(594)**	326
Benefits and expenses paid	**(341)**	(348)	**(339)**	(347)
Other[1]	**—**	2	**—**	(25)
Projected benefit obligation at December 31	**$9,064**	$9,249	**$9,023**	$9,211
Accumulated benefit obligation	**$8,178**	$8,276	**$8,145**	$8,246

(1) In 2005, a Supplemental Executive Retirement Plan was split into two plans. The Utility remained sponsor of the first plan and PG&E Corporation became the sponsor of the second plan.

Other Benefits

	PG&E Corporation		Utility	
(in millions)	2006	2005	2006	2005
Benefit obligation at January 1	**$1,339**	$1,399	**$1,339**	$1,399
Service cost for benefits earned	**28**	30	**28**	30
Interest cost	**74**	74	**74**	74
Actuarial gain	**(105)**	(103)	**(105)**	(103)
Participants paid benefits	**31**	30	**31**	30
Plan amendments	**31**	—	**31**	—
Gross benefits paid	**(92)**	(91)	**(92)**	(91)
Federal subsidy on benefits paid	**4**	—	**4**	—
Benefit obligation at December 31	**$1,310**	$1,339	**$1,310**	$1,339

During 2006, PG&E Corporation and the Utility began including the effects of the federal subsidy under the Medicare Prescription Drug, Improvement and Modernization Act of 2003 in measuring the benefit obligation and the net period benefit cost for the contributory defined benefit medical plans. The net subsidy that will be received by PG&E Corporation and the Utility is used to lower participant premium contributions. The result is a plan amendment increasing the benefit obligation by approximately $31 million and an offsetting actuarial gain of approximately $31 million during 2006, resulting in a zero net effect to the benefit obligation. The federal subsidy had an immaterial effect on the net periodic benefit cost in 2006.

CHANGE IN PLAN ASSETS

To determine the fair value of the plan assets, PG&E Corporation and the Utility use publicly quoted market values and independent pricing services depending on the nature of the assets, as reported by the trustee.

The following tables reconcile aggregate changes in plan assets during 2006 and 2005:

Pension Benefits

	PG&E Corporation		Utility	
(in millions)	**2006**	2005	**2006**	2005
Fair value of plan assets at January 1	**$8,049**	$7,614	**$8,049**	$7,614
Actual return on plan assets	**1,050**	758	**1,050**	758
Company contributions	**300**	25	**298**	24
Benefits and expenses paid	**(371)**	(348)	**(369)**	(347)
Fair value of plan assets at December 31	**$9,028**	$8,049	**$9,028**	$8,049

Other Benefits

	PG&E Corporation		Utility	
(in millions)	**2006**	2005	**2006**	2005
Fair value of plan assets at January 1	**$1,146**	$1,069	**$1,146**	$1,069
Actual return on plan assets	**154**	86	**154**	86
Company contributions	**25**	59	**25**	59
Plan participant contribution	**31**	30	**31**	30
Benefits and expenses paid	**(100)**	(98)	**(100)**	(98)
Fair value of plan assets at December 31	**$1,256**	$1,146	**$1,256**	$1,146

FUNDED STATUS

The following schedule reconciles the plans' aggregate funded status to the prepaid or accrued benefit cost on a plan sponsor basis. The funded status is the difference between the fair value of plan assets and projected benefit obligations.

Pension Benefits

	PG&E Corporation		Utility	
	December 31,		December 31,	
(in millions)	2006	2005	2006	2005
Fair value of plan assets at December 31	**$ 9,028**	$ 8,049	**$ 9,028**	$ 8,049
Projected benefit obligation at December 31	**(9,064)**	(9,249)	**(9,023)**	(9,211)
Funded status plan assets less than projected benefit obligation	**(36)**	(1,200)	**5**	(1,162)
Unrecognized prior service cost	**268**	321	**275**	327
Unrecognized net loss	**318**	1,314	**306**	1,302
Unrecognized net transition obligation	**1**	1	**1**	–
Less: transfer to accumulated other comprehensive income(2)	**(587)**	–	**(582)**	–
Prepaid/(accrued) benefit cost	**$ (36)**	$ 436	**$ 5**	$ 467
Noncurrent asset	**$ 34**	$ –	**$ 34**	$ –
Current liability	**(5)**	–	**(3)**	–
Noncurrent liability	**(65)**	–	**(26)**	–
Prepaid benefit cost	**–**	491	**–**	491
Accrued benefit liability	**–**	(55)	**–**	(24)
Additional minimum liability	**–**	(671)	**–**	(668)
Intangible asset	**–**	332	**–**	332
Excess additional minimum liability(1)	**–**	339	**–**	336
Prepaid/(accrued) benefit cost	**$ (36)**	$ 436	**$ 5**	$ 467

(1) Of this amount, approximately $325 million has been recorded as a reduction to a pension regulatory liability in accordance with the provisions of SFAS No. 71 and the remainder is recorded to other comprehensive income, net of the related income tax benefit, for 2005.

(2) Under SFAS No. 158 this amount is recorded to accumulated other comprehensive income, net of the related income tax benefit, for 2006.

Other Benefits

	PG&E Corporation		Utility	
	December 31,		December 31,	
(in millions)	2006	2005	2006	2005
Fair value of plan assets at December 31	**$ 1,256**	$ 1,146	**$ 1,256**	$ 1,146
Benefit obligation at December 31	**(1,310)**	(1,339)	**(1,310)**	(1,339)
Funded status plan assets less than benefit obligation	**(54)**	(193)	**(54)**	(193)
Unrecognized prior service cost	**114**	132	**114**	132
Unrecognized net gain	**(250)**	(129)	**(250)**	(129)
Unrecognized net transition obligation	**154**	179	**154**	179
Less: transfer to accumulated other comprehensive income(1)	**(18)**	–	**(18)**	–
Accrued benefit cost	**$ (54)**	$ (11)	**$ (54)**	$ (11)
Noncurrent liability	**$ (54)**	$ –	**$ (54)**	$ –
Accrued benefit liability	**–**	(11)	**–**	(11)
Accrued benefit cost	**$ (54)**	$ (11)	**$ (54)**	$ (11)

(1) Under SFAS No. 158 this amount is recorded to accumulated other comprehensive income, net of the related income tax benefit, for 2006.

OTHER INFORMATION

The aggregate projected benefit obligation, accumulated benefit obligation and fair value of plan asset for plans in which the fair value of plan assets is less than the accumulated benefit obligation and the projected benefit obligation as of December 31, 2006 and 2005 were as follows:

	Pension Benefits		Other Benefits	
(in millions)	2006	2005	2006	2005
PG&E Corporation:				
Projected benefit obligation	$(70)	$(9,249)	$(1,310)	$(1,339)
Accumulated benefit obligation	(62)	(8,276)	–	–
Fair value of plan assets	–	8,049	1,256	1,146
Utility:				
Projected benefit obligation	$(29)	$(9,211)	$(1,310)	$(1,339)
Accumulated benefit obligation	(28)	(8,246)	–	–
Fair value of plan assets	–	8,049	1,256	1,146

COMPONENTS OF NET PERIODIC BENEFIT COST

Net periodic benefit cost as reflected in PG&E Corporation's Consolidated Statements of Income for 2006, 2005 and 2004 is as follows:

Pension Benefits

	December 31,		
(in millions)	2006	2005	2004
Service cost for benefits earned	$ 236	$ 214	$ 194
Interest cost	511	500	482
Expected return on plan assets	(640)	(623)	(563)
Amortized prior service cost	56	56	63
Amortization of unrecognized loss	22	29	6
Net periodic benefit cost	$ 185	$ 176	$ 182

Other Benefits

	December 31,		
(in millions)	2006	2005	2004
Service cost for benefits earned	$ 28	$ 30	$ 32
Interest cost	74	74	84
Expected return on plan assets	(90)	(85)	(76)
Amortized prior service cost	14	11	12
Amortization of unrecognized loss (gain)	(3)	(1)	–
Amortization of transition obligation	26	26	26
Net periodic benefit cost	$ 49	$ 55	$ 78

There was no material difference between the Utility's and PG&E Corporation's consolidated net periodic benefit costs.

COMPONENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME

On December 31, 2006, upon adoption of SFAS No. 158, PG&E Corporation and the Utility recorded unrecognized prior service costs, unrecognized gains and losses, and unrecognized net transition obligations as components of accumulated other comprehensive income, net of tax. In subsequent years PG&E Corporation and the Utility will recognize these amounts as components of net periodic benefit cost in accordance with SFAS No. 87 and 106.

Amounts recognized in accumulated other comprehensive income consist of:

	PG&E Corporation		Utility	
(in millions)	2006	2005	2006	2005
Pension Benefits:				
Unrecognized prior service cost	$ 268	$ –	$ 275	$ –
Unrecognized net loss	318	–	306	–
Unrecognized net transition obligation	1	–	1	–
Less: transfer to regulatory account[1]	(574)	–	(574)	–
Total	$ 13	$ –	$ 8	$ –
Other Benefits:				
Unrecognized prior service cost	$ 114	$ –	$ 114	$ –
Unrecognized net gain	(250)	–	(250)	–
Unrecognized net transition obligation	154	–	154	–
Total	$ 18	$ –	$ 18	$ –

(1) The Utility recorded approximately $574 million as a reduction to the existing pension regulatory liability in accordance with the provisions of SFAS No. 71.

The estimated amounts that will be amortized into net periodic benefit cost in 2007 are as follows:

(in millions)	PG&E Corporation	Utility
Pension benefits:		
Unrecognized prior service cost	$ 49	$ 50
Unrecognized net loss	1	–
Unrecognized net transition obligation	1	1
Total	$ 51	$ 51
Other benefits:		
Unrecognized prior service cost	$ 14	$ 14
Unrecognized net gain	(12)	(12)
Unrecognized net transition obligation	26	26
Total	$ 28	$ 28

INCREMENTAL EFFECT OF APPLYING SFAS NO. 158

The following table shows the incremental effect of applying SFAS No. 158 on individual line items in the December 31, 2006, balance sheet:

	PG&E Corporation			Utility		
(in millions)	Before Application	Effect of Adopting SFAS No. 158	**As Reported at December 31, 2006**	Before Application	Effect of Adopting SFAS No. 158	**As Reported at December 31, 2006**
Other Noncurrent Assets						
Other	$ 339	$ 34	**$ 373**	$ 246	$ 34	**$ 280**
Total other noncurrent assets	7,117	34	**7,151**	7,049	34	**7,083**
TOTAL ASSETS	$34,769	$ 34	**$34,803**	$34,337	$ 34	**$34,371**
Current Liabilities						
Accounts payable:						
Other	$ 454	$ (34)	**$ 420**	$ 436	$ (34)	**$ 402**
Deferred income taxes	134	14	**148**	104	14	**118**
Total current liabilities	8,270	(20)	**8,250**	7,700	(20)	**7,680**
Noncurrent Liabilities						
Regulatory liabilities	3,966	(574)	**3,392**	3,966	(574)	**3,392**
Deferred income taxes	2,862	(22)	**2,840**	2,993	(21)	**2,972**
Other	1,392	661	**2,053**	1,263	659	**1,922**
Total noncurrent liabilities	18,425	65	**18,490**	18,427	64	**18,491**
Accumulated other comprehensive income	(8)	(11)	**(19)**	(6)	(10)	**(16)**
Total shareholders' equity	7,822	(11)	**7,811**	8,210	(10)	**8,200**
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$34,769	$ 34	**$34,803**	$34,337	$ 34	**$34,371**

VALUATION ASSUMPTIONS

The following actuarial assumptions were used in determining the projected benefit obligations and the net periodic cost. Weighted average, year-end assumptions were used in determining the plans' projected benefit obligations, while prior year-end assumptions are used to compute net benefit cost.

	Pension Benefits			Other Benefits		
	December 31,			December 31,		
	2006	2005	2004	**2006**	2005	2004
Discount rate	**5.90%**	5.60%	5.80%	**5.50–6.00%**	5.20–5.65%	5.80%
Average rate of future compensation increases	**5.00%**	5.00%	5.00%	**–**	–	–
Expected return on plan assets						
Pension benefits	**8.00%**	8.00%	8.10%	**–**	–	–
Other benefits:						
Defined benefit – medical plan bargaining	**–**	–	–	**8.20%**	8.40%	8.50%
Defined benefit – medical plan non-bargaining	**–**	–	–	**7.30%**	7.60%	7.60%
Defined benefit – life insurance plan	**–**	–	–	**8.20%**	8.40%	8.50%

The assumed health care cost trend rate for 2006 is approximately 9%, decreasing gradually to an ultimate trend rate in 2011 and beyond of approximately 5%. A one-percentage point change in assumed health care cost trend rate would have the following effects:

(in millions)	One-Percentage Point Increase	One-Percentage Point Decrease
Effect on postretirement benefit obligation	$71	$(58)
Effect on service and interest cost	8	(6)

Expected rates of return on plan assets were developed by determining projected stock and bond returns and then applying these returns to the target asset allocations of the employee benefit trusts, resulting in a weighted average rate of return on plan assets. Fixed income returns were projected based on real maturity and credit spreads added to a long-term inflation rate. Equity returns were estimated based on estimates of dividend yield and real earnings growth added to a long-term rate of inflation. For the Utility Retirement Plan, the assumed return of 8.0% compares to a 10-year actual return of 9.0%. The rate used to discount pension and other post-retirement benefit plan liabilities was based on a yield curve developed from market data of over 500 Aa-grade non-callable bonds at December 31, 2006. This yield curve has discount rates that vary based on the duration of the obligations. The estimated future cash flows for the pension and other benefit obligations were matched to the corresponding rates on the yield curve to derive a weighted average discount rate.

The difference between actual and expected return on plan assets is included in net amortization and deferral, and is considered in the determination of future net benefit income (cost). The actual return on plan assets was above the expected return in 2006, 2005 and 2004.

ASSET ALLOCATIONS

The asset allocation of PG&E Corporation's and the Utility's pension and other benefit plans at December 31, 2006 and 2005, and target 2007 allocation, were as follows:

	Pension Benefits			Other Benefits		
	2007	2006	2005	2007	2006	2005
Equity securities						
U.S. equity	37.5%	38%	41%	49%	49%	51%
Non-U.S. equity	17.5%	18%	24%	18%	20%	20%
Global equity	5%	5%	0%	4%	4%	0%
Fixed income securities	40%	39%	35%	29%	27%	29%
Total	100%	100%	100%	100%	100%	100%

Equity securities include a small amount (less than 0.1% of total plan assets) of PG&E Corporation common stock.

The maturity of fixed income securities at December 31, 2006 ranged from zero to 60 years and the average duration of the bond portfolio was approximately 4.6 years. The maturity of fixed income securities at December 31, 2005 ranged from zero to 55 years and the average duration of the bond portfolio was approximately 4.1 years.

PG&E Corporation's and the Utility's investment strategy for all plans is to maintain actual asset weightings within 0.5%–5.5% of target asset allocations varying by asset class. A rebalancing review is triggered whenever the actual weighting exceeds the range of acceptable weighting.

A benchmark portfolio for each asset class is set based on market capitalization and valuations of equities and the durations and credit quality of fixed income securities. Investment managers for each asset class are retained to periodically adjust, or actively manage, the combined portfolio against the benchmark. Active management covers approximately 80% of the U.S. equity, 55% of the non-U.S. equity and virtually 100% of the fixed income and global security portfolios.

CASH FLOW INFORMATION

Employer Contributions

PG&E Corporation and the Utility contributed approximately $300 million to the pension benefits, including $295 million to the qualified defined benefit pension plan, of which $20 million related to 2005, and approximately $25 million to the other benefits in 2006. These contributions are consistent with PG&E Corporation's and the Utility's funding policy, which is to contribute amounts that are tax deductible, consistent with applicable regulatory decisions and federal minimum funding requirements. None of these pension or other benefits were subject to a minimum funding requirement in 2006. The Utility's pension benefits met all the funding requirements under the Employee Retirement Income Security Act of 1974, as amended. PG&E Corporation and the Utility expect to make total contributions of approximately $176 million during 2007 to the qualified defined benefit pension plan. Contribution estimates for the Utility's other benefit plans after 2006 will be driven by future GRC decisions and in line with the Utility's funding policy.

Benefits Payments

The estimated benefits expected to be paid in each of the next five fiscal years and in aggregate for the five fiscal years thereafter, are as follows:

(in millions)	PG&E Corporation	Utility
Pension		
2007	$ 392	$ 390
2008	417	415
2009	441	439
2010	465	462
2011	511	508
2012–2016	2,771	2,757
Other benefits		
2007	$ 80	$ 80
2008	84	84
2009	86	86
2010	89	89
2011	91	91
2012–2016	484	484

DEFINED CONTRIBUTION PENSION PLAN

PG&E Corporation and its subsidiaries also sponsor defined contribution benefit plans. These plans are qualified under applicable sections of the Internal Revenue Code. These plans provide for tax-deferred salary deductions and after-tax employee contributions as well as employer contributions. Employees designate the funds in which their contributions and any employer contributions are invested. Employer contributions include matching of up to 5% of an employee's base compensation and/or basic contributions of up to 5% of an employee's base compensation. Matching employer contributions are automatically invested in PG&E Corporation common stock. Employees may reallocate matching employer contributions and accumulated earnings thereon to another investment fund or funds available to the plan at any time after they have been credited to the employee's account. Employer contribution expense reflected in PG&E Corporation's Consolidated Statements of Income amounted to:

(in millions)	PG&E Corporation	Utility
Year ended December 31,		
2006	**$45**	**$43**
2005	43	42
2004[1]	40	39

(1) Includes NEGT-related amounts within PG&E Corporation.

LONG-TERM INCENTIVE PLAN

On January 1, 2006, the PG&E Corporation 2006 LTIP became effective. The 2006 LTIP permits the award of various forms of incentive awards, including stock options, stock appreciation rights, restricted stock awards, restricted stock units, performance shares, performance units, deferred compensation awards, and other stock-based awards, to eligible employees of PG&E Corporation and its subsidiaries. Non-employee directors of PG&E Corporation are also eligible to receive restricted stock and either stock options or restricted stock units under the formula grant provisions of the 2006 LTIP. A maximum of 12 million shares of PG&E Corporation common stock (subject to adjustment for changes in capital structure, stock dividends, or other similar events) have been reserved for issuance under the 2006 LTIP, of which 11,421,085 shares were available for award at December 31, 2006. The 2006 LTIP was amended on February 15, 2006 to address the vesting of outstanding awards in connection with a change in control of PG&E Corporation.

The 2006 LTIP replaced the PG&E Corporation Long-Term Incentive Program, which expired on December 31, 2005. Awards made under the PG&E Corporation Long-Term Incentive Program before December 31, 2005 and still outstanding continue to be governed by the terms and conditions of the PG&E Corporation Long-Term Incentive Program.

PG&E Corporation and the Utility use an estimated annual forfeiture rate of 2%, based on historic forfeiture rates, for purposes of determining compensation expense for share-based incentive awards. The following table provides a summary of total compensation expense for PG&E Corporation (consolidated) and the Utility (stand-alone) for share-based incentive awards for the year ended December 31, 2006:

(in millions)	PG&E Corporation	Utility
Stock Options	$12	$ 8
Restricted Stock	20	14
Performance Shares	33	24
Total Compensation Expense (pre-tax)	$65	$46
Total Compensation Expense (after-tax)	$39	$27

As discussed in Note 2, "*New and Significant Accounting Policies – Share-Based Payment*," effective January 1, 2006, PG&E Corporation adopted the fair value recognition provisions for share-based payment using the modified prospective application method provided by SFAS No. 123R.

Stock Options

Other than the grant of options to purchase 12,457 shares of PG&E Corporation common stock to non-employee directors of PG&E Corporation in accordance with the formula and nondiscretionary provisions of the 2006 LTIP, no other stock options were granted during 2006. The exercise price of stock options granted under the 2006 LTIP and all other outstanding stock options is equal to the market price of PG&E Corporation's common stock on the date of grant. Stock options generally have a 10-year term and vest over four years of continuous service, subject to accelerated vesting in certain circumstances.

The fair value of each stock option on the date of grant is estimated using the Black-Scholes valuation method. The weighted average grant date fair value of options granted using the Black-Scholes valuation method was $6.98, $10.08 and $8.70 per share in 2006, 2005 and 2004, respectively. The significant assumptions used for shares granted in 2006, 2005 and 2004 were:

	2006	2005	2004
Expected stock price volatility	**22.1%**	40.6%	45.0%
Expected annual dividend payment	**$1.32**	$1.20	$1.20
Risk-free interest rate	**4.46%**	3.74%	3.66%
Expected life	**5.6 years**	5.9 years	6.5 years

Expected volatilities are based on historical volatility of PG&E Corporation's common stock. The expected life of stock options is derived from historical data that estimates stock option exercise and employee departure behavior. The risk-free interest rate for periods within the contractual term of the stock option is based on the U.S. Treasury rates in effect at the date of grant.

The following table summarizes total intrinsic value (fair market value of PG&E Corporation's stock less stock option strike price) of options exercised for PG&E Corporation (consolidated) and the Utility (stand-alone) in 2006, 2005 and 2004:

(in millions)	PG&E Corporation	Utility
2006:		
Intrinsic value of options exercised	**$ 97**	**$51**
2005:		
Intrinsic value of options exercised	$125	$57
2004:		
Intrinsic value of options exercised	$ 83	$44

The tax benefit from stock options exercised totaled $31 million for the year ended December 31, 2006, of which approximately $44 million was recorded by the Utility.

The following table summarizes stock option activity for PG&E Corporation and the Utility for 2006:

Options	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1	11,899,059	$23.26		
Granted[(1)]	12,457	37.47		
Exercised	(5,369,818)	22.05		
Forfeited or expired	(142,728)	25.50		
Outstanding at December 31	**6,398,970**	**23.52**	**5.5**	**$148,248,308**
Expected to vest at December 31	**2,226,843**	**25.29**	**6.9**	**$ 46,872,341**
Exercisable at December 31	**4,115,402**	**17.50**	**3.8**	**$101,375,967**

(1) No stock options were awarded to employees in 2006; however, certain non-employee directors of PG&E Corporation were awarded stock options.

The following table summarizes stock option activity for the Utility for 2006:

Options	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1[(1)]	7,344,455	$23.15		
Granted	—	—		
Exercised	(2,836,769)	22.21		
Forfeited or expired	(105,180)	25.48		
Outstanding at December 31	**4,402,506**	**23.66**	**5.8**	**$104,083,574**
Expected to vest at December 31	**1,571,779**	**25.28**	**6.9**	**$ 33,113,132**
Exercisable at December 31	**2,799,712**	**17.99**	**4.1**	**$ 70,970,442**

(1) Includes net employee transfers between PG&E Corporation and the Utility during 2006.

As of December 31, 2006, there was approximately $16 million of total unrecognized compensation cost related to outstanding stock options, of which $11 million was allocated to the Utility. That cost is expected to be recognized over a weighted average period of 2.4 years for PG&E Corporation and the Utility.

Restricted Stock

During 2006, PG&E Corporation awarded 559,855 shares of PG&E Corporation restricted common stock to eligible participants of PG&E Corporation and its subsidiaries, of which 387,735 shares were awarded to the Utility's eligible participants.

The restricted shares are held in an escrow account. The shares become available to the employees as the restrictions lapse. For the restricted stock awarded in 2003, the restrictions on 80% of the shares lapse automatically over a period of four years at the rate of 20% per year. Restrictions on the remaining 20% of the shares will lapse at a rate of 5% per year if PG&E Corporation's annual total shareholder return, or TSR, is in the top quartile of its comparator group as measured at the end of the immediately preceding year. For restricted stock awarded in 2004 and 2005, there are no performance criteria and the restrictions will lapse ratably over four years. For restricted stock awarded in 2006, the restrictions on 60% of the shares will lapse automatically over a period of three years at the rate of 20% per year. If PG&E Corporation's annual TSR is in the top quartile of its comparator group, as measured for the three immediately preceding calendar years, the restrictions on the remaining 40% of the shares will lapse on the first business day of 2009. If PG&E Corporation's TSR is not in the top quartile for such period, then the restrictions on the remaining 40% of the shares will lapse on the first business day of 2011. Compensation expense related to the portion of the 2006 restricted stock award that is subject to conditions based on TSR is recognized over the shorter of the requisite service period and three years.

The tax benefit from restricted stock which vested during 2006 totaled $4 million for 2006, of which approximately $2 million was recorded by the Utility.

The following table summarizes restricted stock activity for PG&E Corporation and the Utility for 2006:

	Number of Shares of Restricted Stock	Weighted Average Grant-Date Fair Value
Nonvested at January 1	1,399,990	$22.31
Granted	559,855	37.47
Vested	(493,874)	20.97
Forfeited	(88,433)	19.41
Nonvested at December 31	**1,377,538**	**$29.24**

The following table summarizes restricted stock activity for the Utility for 2006:

	Number of Shares of Restricted Stock.	Weighted Average Grant-Date Fair Value
Nonvested at January 1	958,997	$22.48
Granted	387,735	37.47
Vested	(339,362)	21.08
Forfeited	(74,642)	20.74
Nonvested at December 31	**932,728**	**$29.36**

As of December 31, 2006, there was approximately $17 million of total unrecognized compensation cost relating to restricted stock, of which $12 million related to the Utility. PG&E Corporation and the Utility expect to recognize this cost over a weighted average period of 1.3 years.

Performance Shares and Performance Units

During 2006, PG&E Corporation awarded 559,855 performance shares to eligible participants of PG&E Corporation and its subsidiaries, of which 387,735 shares were awarded to the Utility's eligible participants. Performance shares are hypothetical shares of PG&E Corporation common stock that vest at the end of a three-year period and are settled in cash. Upon vesting, the amount of cash that recipients are entitled to receive is based on the average closing price of PG&E Corporation stock for the last 30 calendar days of the year preceding the vesting date and a payout percentage, ranging from 0% to 200%, as measured by PG&E Corporation's TSR relative to its comparator group for the applicable three-year period.

Outstanding performance shares are classified as a liability on the Consolidated Financial Statements of PG&E Corporation and the Utility because the performance shares can only be settled in cash upon satisfaction of the performance criteria. The liability related to the performance shares is marked to market at the end of each reporting period to reflect the market price of PG&E Corporation common stock and the payout percentage at the end of the reporting period. Accordingly, compensation expense recognized for performance shares will fluctuate with PG&E Corporation's common stock price and its performance relative to its peer group.

The following table summarizes performance share activity for PG&E Corporation and the Utility for 2006:

	Number of Performance Shares
Nonvested at January 1	803,975
Granted	559,855
Vested	(469,023)
Forfeited	(62,201)
Nonvested at December 31	**832,606**

The following table summarizes performance shares activity for the Utility for 2006:

	Number of Performance Shares
Nonvested at January 1	566,086
Granted	387,735
Vested	(319,119)
Forfeited	(51,105)
Nonvested at December 31	**583,597**

PG&E Corporation Supplemental Retirement Savings Plan

The supplemental retirement savings plan provides supplemental retirement alternatives to eligible officers and key employees of PG&E Corporation and its subsidiaries by allowing participants to defer portions of their compensation, including salaries and amounts awarded under various incentive awards and to receive supplemental employer-provided retirement benefits. Under the employee-elected deferral component of the plan, eligible employees may defer all or part of their incentive awards and 5% to 50% of their salary. Under the supplemental employer-provided retirement benefits component of the plan, eligible employees may receive full credit for employer matching and basic contributions, under the respective defined contribution plan, in excess of limitations set by the Internal Revenue Code. A separate non-qualified account is maintained for each eligible employee to track deferred amounts. The account's value is adjusted in accordance with the performance of the investment options selected by the employee. Each employee's account is adjusted on a quarterly basis, and the change in value is recorded as additional compensation expense or income in the Consolidated Financial Statements. Total compensation expense recognized by PG&E Corporation and the Utility in connection with the plan amounted to:

(in millions)	PG&E Corporation	Utility
2006:	**$4**	**$2**
2005:	3	1
2004:	3	1

NOTE 15: THE UTILITY'S EMERGENCE FROM CHAPTER 11

As a result of the California energy crisis, the Utility filed a voluntary petition for relief under the provisions of Chapter 11 on April 6, 2001. The Utility retained control of its assets and was authorized to operate its business as a debtor-in-possession during its Chapter 11 proceeding. PG&E Corporation and the subsidiaries of the Utility, including PG&E Funding, LLC, which issued rate reduction bonds, and PG&E Holdings, LLC, which holds stock of the Utility, were not included in the Utility's Chapter 11 proceeding.

The Utility emerged from Chapter 11 when its plan of reorganization became effective on April 12, 2004, or the Effective Date. The plan of reorganization incorporated the terms of the Chapter 11 Settlement Agreement. Although the Utility's operations are no longer subject to the oversight of the bankruptcy court, the bankruptcy court retains jurisdiction to hear and determine disputes arising in connection with the interpretation, implementation or enforcement of (1) the Chapter 11 Settlement Agreement, (2) the plan of reorganization and (3) the bankruptcy court's December 22, 2003 order confirming the plan of reorganization. In addition, the bankruptcy court retains jurisdiction to resolve remaining disputed claims.

At December 31, 2004, the Utility had accrued approximately $2.1 billion for remaining disputed claims. Since December 31, 2004, the Utility has made payments to creditors of approximately $29 million in settlement of disputed claims and, as a result of settlements reached with creditors, has reduced the disputed claims balance by approximately $404 million. The Utility held $1.2 billion in escrow for the payment of the remaining disputed claims as of December 31, 2006. Upon resolution of these claims and under the terms of the Chapter 11 Settlement Agreement, any net refunds, claim offsets or other credits that the Utility receives from energy suppliers will be returned to customers. With the approval of the bankruptcy court, the Utility has withdrawn certain amounts from the escrow in connection with settlements with certain CAISO and Power Exchange, or PX, sellers. As of December 31, 2006, the amount of the accrual was approximately $1.2 billion for remaining net disputed claims, consisting of approximately $1.7 billion of accounts payable-disputed claims primarily payable to the CAISO and the PX, offset by an accounts receivable from the CAISO and the PX of approximately $0.5 billion.

NOTE 16: RELATED PARTY AGREEMENTS AND TRANSACTIONS

In accordance with various agreements, the Utility and other subsidiaries provide and receive various services to and from their parent, PG&E Corporation, and among themselves. The Utility and PG&E Corporation exchange administrative and professional services in support of operations. Services provided directly to PG&E Corporation by the Utility are priced at the higher of fully loaded cost (i.e., direct costs and allocations of overhead costs) or fair market value, depending on the nature of the services. Services provided directly to the Utility by PG&E Corporation are priced at the lower of fully loaded cost or fair market value, depending on the nature of the services. PG&E Corporation also allocates certain other corporate administrative and general costs, at cost, to the Utility and other subsidiaries using agreed upon allocation factors, including the number of employees, operating expenses excluding fuel purchases, total assets and other cost allocation methodologies. The Utility's significant related party transactions and related receivable (payable) balances were as follows:

(in millions)	Year ended December 31, 2006	2005	2004	Receivable (Payable) Balance Outstanding at Year ended December 31, 2006	2005
Utility revenues from:					
Administrative services provided to PG&E Corporation	$ 5	$ 5	$ 8	$ 2	$ 2
Utility employee benefit assets due from PG&E Corporation	–	–	–	25	23
Interest from PG&E Corporation on employee benefit assets	1	–	–	–	–
Utility expenses from:					
Administrative services received from PG&E Corporation	$108	$111	$81	$(40)	$(37)
Utility employee benefit payments due to PG&E Corporation	3	–	–	–	–
Interest accrued on pre-petition liabilities due to PG&E Corporation	–	–	2	–	–
Natural gas transportation services received from GTNW	–	–	43	–	–

NOTE 17: COMMITMENTS AND CONTINGENCIES

PG&E Corporation and the Utility have substantial financial commitments in connection with agreements entered into to support the Utility's operating activities. PG&E Corporation has no ongoing financial commitments relating to NEGT's current operating activities. PG&E Corporation and the Utility also have significant contingencies arising from their operations, including contingencies related to guarantees, power purchases made during the 2000–2001 energy crisis, regulatory proceedings, nuclear operations, employee matters, environmental compliance and remediation and legal matters.

COMMITMENTS

PG&E CORPORATION

PG&E Corporation agreed to accept the assignment of certain Canadian natural gas pipeline firm transportation contracts effective November 1, 2007, through October 31, 2023, the remaining term of the contracts' duration. The firm quantity under the contracts is approximately 50 million cubic feet per day and PG&E Corporation has estimated annual reservation charges will range between approximately $8 million and $12 million. During the term of the contracts, the applicable reservation charges will equal the full tariff rates set by regulatory authorities in Canada and the United States, as applicable. PG&E Corporation is unable to predict the utilization of these contracts, which will depend on market prices, customer demand and approval of cost recovery by the CPUC among other factors.

PG&E Corporation also has operating lease obligations related to office space. Contracts have expiration terms that range from November 2008 to February 2012. PG&E's commitment under these contracts is approximately $13 million.

UTILITY

Third-Party Power Purchase Agreements

Qualifying Facility Power Purchase Agreements — Under the Public Utility Regulatory Policies Act of 1978, or PURPA, electric utilities were required to purchase energy and capacity from independent power producers that are qualifying co-generation facilities, or QFs. To implement the purchase requirements of PURPA, the CPUC required California investor-owned electric utilities to enter into long-term power purchase agreements with QFs and approved the applicable terms, conditions, prices and eligibility requirements. These agreements require the Utility to pay for energy and capacity. Energy payments are based on the QF's actual electrical output and CPUC-approved energy prices, while capacity payments are based on the QF's total available capacity and contractual capacity commitment. Capacity payments may be adjusted if the QF fails to meet or exceeds performance requirements specified in the applicable power purchase agreement.

The Energy Policy Act of 2005 significantly amended the purchase requirements of PURPA. As amended, Section 210(m) of PURPA authorizes the FERC to waive the obligation of an electric utility under Section 210 of PURPA to purchase the electricity offered to it by a QF (under a new contract or obligation) if the FERC finds that the QF has nondiscriminatory access to one of three defined categories of competitive wholesale electricity markets. The statute permits such waivers as to a particular QF or on a "service territory-wide basis." The Utility plans to wait until after the new day-ahead market structure provided for in the CAISO's Market Redesign and Technology Update, or MRTU, initiative to restructure the California electricity market becomes effective to assess whether it will file a request with the FERC to terminate its obligations under PURPA to enter into new QF purchase obligations.

As of December 31, 2006, the Utility had agreements with 268 QFs for approximately 4,150 megawatts, or MW, that are in operation. Agreements for approximately 3,800 MW expire at various dates between 2007 and 2028. QF power purchase agreements for approximately 350 MW have no specific expiration dates and will terminate only when the owner of the QF exercises its termination option. The Utility also has power purchase agreements with approximately 68 inoperative QFs. The total of approximately 4,150 MW consists of approximately 2,550 MW from cogeneration projects, 600 MW from wind projects and 1,000 MW from projects with other fuel sources, including biomass, waste-to-energy, geothermal, solar and hydroelectric.

QF power purchase agreements accounted for approximately 20% of the Utility's 2006 electricity sources, 22% of the Utility's 2005 electricity sources and approximately 23% of the Utility's 2004 electricity sources. No single QF accounted for more than 5% of the Utility's 2006, 2005 or 2004 electricity sources.

There are proceedings pending at the CPUC that may impact the amount of payments to QFs, the number of QFs holding power purchase agreements with the Utility, as well as the outcome of the Utility's request for refunds for overpayments from June 2000 through March 2001 that were made to QFs pursuant to CPUC orders at approved rates. The CPUC will address whether certain payments for short-term power deliveries required by the power purchase agreements comply with the pricing requirements of PURPA. The CPUC is also considering whether to require the California investor-owned electric utilities to enter into new power purchase agreements with existing QFs that have expiring power purchase agreements and with newly-constructed QFs and if so, specify the appropriate level of compensation for power purchased under such new agreements. PG&E Corporation and the Utility are unable to predict the outcome of these proceedings.

The CPUC is considering various policy and pricing issues related to power purchased from QFs in several rulemaking proceedings. It is expected that a proposed decision addressing those issues will be issued soon. In April 2006, the Utility and the Independent Energy Producers, or IEP, on behalf of certain QFs, entered into a settlement agreement to resolve these issues irrespective of how the CPUC ultimately resolves these issues. These issues, however, remain unresolved for the QFs that did not accept the terms of the settlement agreement. In July 2006, the CPUC approved the IEP settlement agreement and the QF amendments which implement the agreement with the settling QFs. As of December 31, 2006, 122 QFs were subject to such amendments of their existing contracts with the Utility which reduce the Utility's energy payments and establish a new five-year fixed pricing option for QFs that do not use natural gas as their fuel source. The IEP settlement agreement also resolves certain energy crisis claims among the Utility and the settling QFs that are pending in another CPUC proceeding. When a final decision addressing these issues is issued by the CPUC, the Utility will re-evaluate the accounting treatment for QF contracts that are affected by the decision.

As a result of the amendments, several of the QF contracts became subject to lease accounting under SFAS No. 13, "Accounting for Leases," or SFAS No. 13, due to the nature of the fixed capacity payments. SFAS No. 13 requires the Utility to recognize capital lease obligations and assets equal to the present value of the fixed capacity payments under the QF agreements that are treated as capital leases. Accordingly, the Utility's Consolidated Balance Sheet has included in Current Liabilities – Other and Noncurrent Liabilities – Other of approximately $27 million and $372 million, respectively, as of December 31, 2006, representing the present value of the fixed capacity payments due under these contracts. The corresponding assets of $399 million, including amortization of $9 million, are included in plant, property and equipment on the Utility's Consolidated Balance Sheet at December 31, 2006.

In accordance with the settlement between the Utility and Mirant Corporation and certain of its subsidiaries; or Mirant, related to claims outstanding in Mirant's Chapter 11 proceeding, the Utility entered into contracts with several of Mirant's units in the Utility's service territory. In July 2006, the Utility and Mirant entered into two new contracts, which both supplemented and partially superseded the contracts from the settlement, resulting in further savings for the Utility's customers. The new contracts, one for 2007 and one for a multi-year period beginning in January 2008, give the Utility the right to dispatch power from 1,985 MW of units owned by Mirant subsidiaries to meet local reliability and peak period energy needs. In August 2006, the Utility filed an advice letter seeking CPUC approval for the multi-year contract and expects possible action during the first quarter of 2007.

Irrigation Districts and Water Agencies — The Utility has contracts with various irrigation districts and water agencies to purchase hydroelectric power. Under these contracts, the Utility must make specified semi-annual minimum payments based on the irrigation districts' and water agencies' debt service requirements, whether or not any hydroelectric power is supplied, and variable payments for operation and maintenance costs incurred by the suppliers. These contracts expire on various dates from 2007 to 2031. The Utility's irrigation district and water agency contracts accounted for approximately 6% of the Utility's 2006 electricity sources and approximately 5% of the Utility's 2005 and 2004 electricity sources.

Renewable Energy Contracts — California law requires that each California retail seller of electricity, except for municipal utilities, increase its purchases of renewable energy (such as biomass, wind, solar and geothermal energy) by at least 1% of its retail sales per year, so that the amount of electricity purchased from renewable resources equals at least 20% of its total retail sales by the end of 2010. During 2006, the Utility entered into several new renewable power purchase contracts that will help the Utility meet its goals.

Long-Term Power Purchase Agreements — After competitive solicitations, bilateral negotiations and request for offers or proposals were conducted, the Utility entered into several agreements with third-party power providers during 2006 to meet the Utility's intermediate and long-term generation resource needs. Under these agreements, the Utility will purchase power from facilities as late as 2010. These combined agreements cover an aggregate of 7,129 MW of contractual capacity that expire between December 31, 2010 and August 31, 2029. Payments are not required under these agreements until the underlying generation facilities are operational.

Annual Receipts and Payments — The payments made under QFs, irrigation district and water agency, renewable energy and other power purchase agreements during 2004 through 2006 were as follows:

(in millions)	2006	2005	2004
Qualifying facility energy payments	$661	$663	$701
Qualifying facility capacity payments	366	372	382
Irrigation district and water agency payments	64	54	61
Renewable energy and capacity payments	429	405	406
Other power purchase agreement payments	670	774	834

Because the Utility acts as only an agent for the DWR the amounts described above do not include payments related to DWR power purchases.

At December 31, 2006, the undiscounted future expected power purchase agreement payments were as follows:

	Qualifying Facility		Irrigation District & Water Agency		Renewable		Other	
(in millions)	Energy	Capacity	Operations & Maintenance	Debt Service	Energy	Capacity	Energy	Capacity
2007	$ 1,195	$ 477	$ 54	$26	$ 148	$ 18	$ 50	$201
2008	1,276	468	34	4	205	21	41	169
2009	1,159	428	32	–	254	18	40	171
2010	995	391	31	–	294	14	11	158
2011	930	377	30	–	315	14	5	44
Thereafter	5,941	2,601	114	–	2,979	76	11	18
Total	$11,496	$4,742	$295	$30	$4,195	$161	$158	$761

The following table shows the future fixed capacity payments due under the QF contracts that are treated as capital leases. These amounts are also included in the table above. The fixed capacity payments are discounted to the present value shown in the table below using the Utility's incremental borrowing rate at the inception of the leases. The amount of this discount is shown in the table below as the amount representing interest.

(in millions)	
2007	$ 50
2008	50
2009	50
2010	50
2011	50
Thereafter	303
Total fixed capacity payments	553
Less: Amount representing interest	154
Present value of fixed capacity payments	**$399**

Interest and amortization expense associated with the lease obligation is included in the cost of electricity on PG&E Corporation's and the Utility's Consolidated Statements of Income. In accordance with SFAS No. 71, the timing of the Utility's recognition of the lease expense will conform to the ratemaking treatment for the Utility's recovery of the cost of electricity. The QF contracts that are treated as capital leases expire between April 2014 and September 2021.

Capacity payments are based on the QF's total available capacity and contractual capacity commitment. Capacity payments may be adjusted if the QF fails to meet or exceeds performance requirements specified in the applicable power purchase agreement.

Natural Gas Supply and Transportation Commitments

The Utility purchases natural gas directly from producers and marketers in both Canada and the United States to serve its core customers. The contract lengths and natural gas sources of the Utility's portfolio of natural gas procurement contracts have fluctuated, generally based on market conditions.

At December 31, 2006, the Utility's undiscounted obligations for natural gas purchases and gas transportation services were as follows:

(in millions)	
2007	$ 954
2008	151
2009	25
2010	8
2011	–
Thereafter	–
Total	$1,138

Payments for natural gas purchases and gas transportation services amounted to approximately $2.2 billion in 2006, $2.5 billion in 2005 and $1.8 billion in 2004.

Nuclear Fuel Agreements

The Utility has entered into several purchase agreements for nuclear fuel. These agreements have terms ranging from two to five years and are intended to ensure long-term fuel supply. A total of five new contracts were executed in 2006 for deliveries in 2006 to 2010. One existing services contract was extended for five additional years. In most cases, the Utility's nuclear fuel contracts are requirements-based. The Utility relies on established international producers of nuclear fuel in order to diversify its sources and provide security of supply. Pricing terms also are diversified, ranging from fixed prices to market-based prices to base prices that are escalated using published indices.

At December 31, 2006, the undiscounted obligations under nuclear fuel agreements were as follows:

(in millions)	
2007	$135
2008	86
2009	66
2010	64
2011	37
Thereafter	151
Total	$539

Payments for nuclear fuel amounted to approximately $106 million in 2006, $65 million in 2005 and $119 million in 2004.

Reliability Must Run Agreements

The CAISO has entered into reliability must run, or RMR, agreements with various power plant owners, including the Utility, that require designated units in certain power plants, known as RMR units, to remain available to generate electricity upon the CAISO's demand when needed for local transmission system reliability. As a participating transmission owner under the Transmission Control Agreement, the Utility is responsible for the CAISO's costs paid under RMR agreements to power plant owners within or adjacent to the Utility's service territory. RMR agreements are established or extended on an annual basis. During 2006, the CPUC adopted rules to implement state law requirements for California investor-owned utilities to meet resource adequacy requirements, including rules to address local transmission system reliability issues. As the utilities fulfill their responsibility to meet these requirements, the number of RMR agreements with the CAISO and the associated costs will decline. At December 31, 2006, the Utility estimated that it could be obligated to pay the CAISO approximately $75 million for costs to be incurred under these RMR agreements during 2007. The Utility recovers these costs from customers.

In October 2006, the Utility, the California Electricity Oversight Board, and certain other owners of RMR plants, entered into a settlement agreement to resolve complaints that these RMR plant owners charged excessive rates. The settlement agreement has been approved by the CPUC, the FERC, and the bankruptcy court adjudicating the Chapter 11 proceedings of some of the RMR plant owners. The Utility expects that it will receive refunds of approximately $61 million for amounts paid under RMR contracts in 2006 in the first quarter of 2007. Any refunds would be credited to the Utility's electricity customers.

Other Commitments and Operating Leases

The Utility has other commitments relating to operating leases, capital infusion agreements, equipment replacements, the self-generation incentive program exchange agreements, energy efficiency programs and telecommunication contracts. At December 31, 2006, the future minimum payments related to other commitments were as follows:

(in millions)	
2007	$160
2008	33
2009	18
2010	12
2011	11
Thereafter	34
Total	$268

Payments for other commitments amounted to approximately $100 million in 2006, $146 million in 2005 and $111 million in 2004.

Underground Electric Facilities

At December 31, 2006, the Utility was committed to spending approximately $211 million for the conversion of existing overhead electric facilities to underground electric facilities. These funds are conditionally committed depending on the timing of the work, including the schedules of the respective cities, counties and telephone utilities involved. The Utility expects to spend approximately $50 million to $60 million each year in connection with these projects. Consistent with past practice, the Utility expects that these capital expenditures will be included in rate base as each individual project is completed and recoverable in rates charged to customers.

CONTINGENCIES.

PG&E CORPORATION

PG&E Corporation retains a guarantee related to certain NEGT indemnity obligations that were issued to the purchaser of an NEGT subsidiary company. PG&E Corporation's sole remaining exposure relates to any potential environmental obligations that were known to NEGT at the time of the sale but not disclosed to the purchaser and is limited to $150 million. PG&E Corporation has never received any claims nor does it consider it probable any claims will be made under the guarantee. Accordingly, PG&E Corporation has made no provision for this guarantee at December 31, 2006.

UTILITY

PX Block-Forward Contracts

In February 2001, during the energy crisis, the California Governor seized all of the Utility's contracts for the forward delivery of power in the PX California market, otherwise known as "block-forward contracts," for the benefit of the state under California's Emergency Services Act. These block-forward contracts had an estimated unrealized value of up to $243 million when seized. The Utility, the PX, and some of the PX market participants have filed competing claims in state court against the State of California to recover the value of these seized contracts. In November 2005, the PX assigned its interest in this litigation to certain market participants that elected to take assignment of the litigation, subject to the terms and conditions of a settlement agreement approved by the FERC. A motion by the PX for court approval of the assignment is pending in the Sacramento Superior Court; the State of California disputes this assignment. The State of California also disputes the plaintiffs' rights to recovery in the litigation and disputes that the plaintiffs were damaged in any way, arguing that the contracts had no value beyond the price at which the block-forward transactions were executed. This state court litigation is pending. Although the Utility has recorded a receivable of approximately $243 million relating to the estimated value of the contracts at the time of seizure, the Utility also has established a reserve of $243 million for these contracts. If the Utility ultimately prevails, it would record income in the amount of any recovery. PG&E Corporation and the Utility are unable to predict the outcome of this litigation or the amount of any potential recovery.

California Energy Crisis Proceedings

Several parties, including the Utility and the State of California, are seeking refunds on behalf of California electricity purchasers from electricity suppliers, including municipal and governmental entities, for overcharges incurred in the CAISO and PX wholesale electricity markets between May 2000 and June 2001 through various proceedings pending at the FERC and other judicial proceedings. Many issues raised in these proceedings, including the extent of the FERC's refund authority, and the amount of potential refunds after taking into account certain costs incurred by the electricity suppliers, have not been resolved. It is uncertain when these proceedings will be concluded.

The Utility has entered into settlements with various electricity suppliers resolving certain disputed claims and the Utility's refund claims against these electricity suppliers. The Utility has received consideration of approximately $1 billion under these settlements through cash proceeds, reductions to the Utility's PX liability and a partially constructed generating facility (Gateway). With the approval of the bankruptcy court, the Utility has withdrawn certain amounts from escrow (classified as restricted cash in the Consolidated Balance Sheets) in connection with certain of these settlements (see further discussion in Note 15). These settlement agreements provide that the amounts payable by the parties are, in some instances, subject to adjustment based on the outcome of the various issues being considered by the FERC. Additional settlement discussions with other electricity suppliers are ongoing. Future amounts received under these settlements, and any future settlements with electricity suppliers, will be credited to customers after deductions for contingencies and amounts related to certain wholesale power purchases.

PG&E Corporation and the Utility are unable to predict when the FERC proceedings will ultimately be resolved and the amount of any potential refunds the Utility may receive.

Nuclear Insurance

The Utility has several types of nuclear insurance for Diablo Canyon and Humboldt Bay Unit 3. The Utility has insurance coverage for property damages and business interruption losses as a member of Nuclear Electric Insurance Limited, or NEIL. NEIL is a mutual insurer owned by utilities with nuclear facilities. NEIL provides property damage and business interruption coverage of up to $3.24 billion per incident for Diablo Canyon. In addition, NEIL provides $131 million of property damage insurance for Humboldt Bay Unit 3. Under this insurance, if any nuclear generating facility insured by NEIL suffers a catastrophic loss causing a prolonged outage, the Utility may be required to pay an additional premium of up to $41.4 million per one-year policy term.

NEIL also provides coverage for damages caused by acts of terrorism at nuclear power plants. If one or more acts of domestic terrorism cause property damage covered under any of the nuclear insurance policies issued by NEIL to any NEIL member within a 12-month period, the maximum recovery under all those nuclear insurance policies may not exceed $3.24 billion plus the additional amounts recovered by NEIL for these losses from reinsurance. There is no policy coverage limitation for an act caused by foreign terrorism because NEIL would be entitled to receive substantial reimbursement by the federal government under the Terrorism Risk Insurance Extension Act of 2005. The Terrorism Risk Insurance Extension Act of 2005 expires on December 31, 2007.

Under the Price-Anderson Act, public liability claims from a nuclear incident are limited to $10.8 billion. As required by the Price-Anderson Act, the Utility purchased the maximum available public liability insurance of $300 million for Diablo Canyon. The balance of the $10.8 billion of liability protection is covered by a loss-sharing program among utilities owning nuclear reactors. Under the Price-Anderson Act, owner participation in this loss-sharing program is required for all owners of nuclear reactors that are licensed to operate, designed for the production of electrical energy, and have a rated capacity of 100 MW or higher. If a nuclear incident results in costs in excess of $300 million, then the Utility may be responsible for up to $100.6 million per reactor, with payments in each year limited to a maximum of $15 million per incident until the Utility has fully paid its share of the liability. Since Diablo Canyon has two nuclear reactors each with a rated capacity of over 100 MW, the Utility may be assessed up to $201.2 million per incident, with payments in each year limited to a maximum of $30 million per incident. Under the Energy Policy Act of 2005, the Price-Anderson Act was extended through December 31, 2025. Both the maximum assessment per reactor and the maximum yearly assessment will be adjusted for inflation beginning August 31, 2008.

In addition, the Utility has $53.3 million of liability insurance for Humboldt Bay Unit 3 and has a $500 million indemnification from the NRC, for public liability arising from nuclear incidents covering liabilities in excess of the $53.3 million of liability insurance.

California Department of Water Resources Contracts

Electricity from the DWR contracts to the Utility provided approximately 24% of the electricity delivered to the Utility's customers for 2006. The DWR purchased the electricity under contracts with various generators. The Utility, as an agent, is responsible for administration and dispatch of the DWR's electricity procurement contracts allocated to the Utility for purposes of meeting a portion of the Utility's short or long position. A short position results when customer demand, plus applicable reserve margins, exceeds the amount of electricity procured from the Utility's own generation facilities, purchase contracts or DWR contracts allocated to the Utility's customers. In order to satisfy the short position, the Utility would be required to purchase electricity on the spot and forward markets, possibly at a loss. Conversely, a long position results when the contracted supply of energy exceeds customer demand. When in a long position, the Utility would be required to sell the excess capacity in the forward and spot markets, at a gain or possibly at a loss. The DWR remains legally and financially responsible for its electricity procurement contracts. The Utility acts as a billing and collection agent of the DWR's revenue requirements from the Utility's customers.

The DWR contracts currently allocated to the Utility terminate at various dates through 2015, and consist of must-take and capacity charge contracts. Under must-take contracts, the DWR must take and pay for electricity generated by the applicable generating facilities regardless of whether the electricity is needed. Under capacity charge contracts, the DWR must pay a capacity charge but is not required to purchase electricity unless the Utility dispatches the resource and delivers the required electricity. In the Utility's CPUC-approved long-term integrated energy resource plan, the Utility has not assumed that the DWR contracts will be renewed beyond their current expiration dates.

The DWR has stated publicly in the past that it intends to transfer full legal title to, and responsibility for, the DWR power purchase contracts to the California investor-owned electric utilities as soon as possible. However, the DWR power purchase contracts cannot be transferred to the Utility without the consent of the CPUC. The Chapter 11 Settlement Agreement provides that the CPUC will not require the Utility to accept an assignment of, or to assume legal or financial responsibility for, the DWR power purchase contracts unless each of the following conditions has been met:

- After assumption, the Utility's issuer rating by Moody's will be no less than A2 and the Utility's long-term issuer credit rating by S&P will be no less than A;
- The CPUC first makes a finding that the DWR power purchase contracts to be assumed are just and reasonable; and
- The CPUC has acted to ensure that the Utility will receive full and timely recovery in its retail electricity rates of all costs associated with the DWR power purchase contracts to be assumed without further review.

SEVERANCE IN CONNECTION WITH EFFORTS TO ACHIEVE COST AND OPERATING EFFICIENCIES

In connection with the Utility's continued effort to streamline processes and achieve cost and operating efficiencies through implementation of various initiatives, jobs from numerous Utility locations around California are being consolidated. As a result, a number of positions have been eliminated. The Utility expects that more positions will be eliminated. Impacted employees have the option to elect severance or reassignment.

Estimating severance costs requires the Utility to predict whether employees will elect severance or reassignment, and the number of available vacant positions for employees wishing to be reassigned. Depending on the employees' elections, costs will further vary based on the employees' years of service and annual salary. Given the uncertainty of each of these variables, the estimated range is relatively wide. At December 31, 2006, the Utility's future severance expenses related to these initiatives are expected to range from $34 million to approximately $68 million, of which the Utility has recorded the low end as of December 31, 2006. The following table presents the changes in the liability from December 31, 2005:

(in millions)	
Balance at December 31, 2005	$ 2
Expenses	36
Less: Payments	(4)
Balance at December 31, 2006	**$34**

ENVIRONMENTAL MATTERS

The Utility may be required to pay for environmental remediation at sites where it has been, or may be, a potentially responsible party under the Comprehensive Environmental Response Compensation and Liability Act of 1980, as amended, and similar state environmental laws. These sites include former manufactured gas plant sites, power plant sites, and sites used by the Utility for the storage, recycling or disposal of potentially hazardous materials. Under federal and California laws, the Utility may be responsible for remediation of hazardous substances even if the Utility did not deposit those substances on the site.

The cost of environmental remediation is difficult to estimate. The Utility records an environmental remediation liability when site assessments indicate remediation is probable and it can estimate a range of reasonably likely clean-up costs. The Utility reviews its remediation liability on a quarterly basis for each site where it may be exposed to remediation responsibilities. The liability is an estimate of costs for site investigations, remediation, operations and maintenance, monitoring and site closure using current technology, enacted laws and regulations, experience gained at similar sites, and an assessment of the probable level of involvement and financial condition of other potentially responsible parties. Unless there is a better estimate within this range of possible costs, the Utility records the costs at the lower end of this range. The Utility estimates the upper end of this cost range using reasonably possible outcomes that are least favorable to the Utility. It is reasonably possible that a change in these estimates may occur in the near term due to uncertainty concerning the Utility's responsibility, the complexity of environmental laws and regulations, and the selection of compliance alternatives.

The Utility had an undiscounted environmental remediation liability of approximately $511 million at December 31, 2006 and approximately $469 million at December 31, 2005. The increase in the undiscounted environmental remediation reflects an increase of $74 million for remediation at the Utility's gas compressor stations located near Hinkley, California and Topock, Arizona. The portion of the increased liability of $39 million for remediation at the Hinkley facility is attributable to changes in the California Regional Water Quality Control Board's imposed remediation levels. Costs incurred at this facility are not recoverable from customers and, as a result, the after-tax impact on income was a reduction of approximately $23 million for 2006. Ninety percent of the estimated remediation costs associated with the Utility's gas compressor station located near Topock, Arizona will be recoverable in rates in accordance with the hazardous waste ratemaking mechanism which permits the Utility to recover 90% of hazardous waste remediation costs from customers without a reasonableness review.

The $511 million accrued at December 31, 2006 includes:

- approximately $238 million for remediation at the Hinkley and Topock natural gas compressor sites;
- approximately $98 million related to the pre-closing remediation liability associated with divested generation facilities; and
- approximately $175 million related to remediation costs for the Utility's generation facilities and gas gathering sites, third-party disposal sites, and manufactured gas plant sites owned by the Utility or third parties (including those sites that are the subject of remediation orders by environmental agencies or claims by the current owners of the former manufactured gas plant sites).

Of the approximately $511 million environmental remediation liability, approximately $138 million has been included in prior rate setting proceedings. The Utility expects that an additional amount of approximately $272 million will be allowable for inclusion in future rates. The Utility also recovers its costs from insurance carriers and from other third parties whenever possible. Any amounts collected in excess of the Utility's ultimate obligations may be subject to refund to customers.

The Utility's undiscounted future costs could increase to as much as $782 million if the other potentially responsible parties are not financially able to contribute to these costs, or if the extent of contamination or necessary remediation is greater than anticipated. The amount of approximately $782 million does not include any estimate for any potential costs of remediation at former manufactured gas plant sites in the Utility's service territory that were previously owned by the Utility or a predecessor but that are now owned by others because the Utility either has not been able to determine if a liability exists with respect to these sites or the Utility has not been able to estimate the amount of any future potential remediation costs that may be incurred for these sites.

In July 2004, the U.S. Environmental Protection Agency, or EPA, published regulations under Section 316(b) of the Clean Water Act for cooling water intake structures. The regulations affect existing electricity generation facilities using over 50 million gallons per day, typically including some form of "once-through" cooling. The Utility's Diablo Canyon power plant is among an estimated 539 generation facilities nationwide that are affected by this rulemaking. The Utility permanently closed its Hunters Point Power Plant in May 2006 and the Humboldt Bay Power Plant will be re-powered without the use of once-through cooling. The EPA regulations establish a set of performance standards that vary with the type of water body and that are intended to reduce impacts to aquatic organisms. Significant capital investment may be required to achieve the standards. The regulations allow site-specific compliance determinations if a facility's cost of compliance is significantly greater than either the benefits achieved or the compliance costs considered by the EPA and also allow the use of environmental mitigation or restoration to meet compliance requirements in certain cases. Various parties challenged the EPA's regulations, and the cases were consolidated in the U.S. Court of Appeals for the Second Circuit, or Second Circuit.

On January 25, 2007, the Second Circuit issued its decision on the appeals of the EPA Section 316(b) regulations. The Second Circuit remanded significant provisions of the regulations to EPA for reconsideration and held that a cost benefit test cannot be used to establish performance standards or to grant variances from the standards. The Second Circuit also ruled that environmental restoration cannot be used to achieve compliance. The parties may seek either en banc review by the Second Circuit or review by the U.S. Supreme Court. Regardless of whether the decision is subject to further judicial review, the EPA will likely require significant time to review and revise the regulations. It is uncertain how the Second Circuit decision will affect development of the state's proposed implementation policy. The regulatory uncertainty is likely to continue and the Utility's cost of compliance, while likely to be significant, will remain uncertain as well.

LEGAL MATTERS

In the normal course of business, PG&E Corporation and the Utility are named as parties in a number of claims and lawsuits. The most significant of these are discussed below.

In accordance with SFAS No. 5, "Accounting for Contingencies," PG&E Corporation and the Utility make a provision for a liability when it is both probable that a liability has been incurred and the amount of the loss can be reasonably estimated. These provisions are reviewed quarterly and adjusted to reflect the impacts of negotiations, settlements and payments, rulings, advice of legal counsel and other information and events pertaining to a particular case. In assessing such contingencies, PG&E Corporation's and the Utility's policy is to exclude anticipated legal costs.

The accrued liability for legal matters is included in PG&E Corporation's and the Utility's other noncurrent liabilities in the Consolidated Balance Sheets, and totaled approximately $74 million at December 31, 2006 and approximately $388 million at December 31, 2005.

PG&E Corporation and the Utility do not believe it is probable that losses associated with legal matters that exceed amounts already recognized will be incurred in amounts that would be material to PG&E Corporation's or the Utility's financial condition or results of operations.

Chromium Litigation

In accordance with the terms of a settlement agreement entered into on February 3, 2006, on April 21, 2006, the Utility released $295 million from escrow for payment to approximately 1,100 plaintiffs who had filed complaints against the Utility in the Superior Court for the County of Los Angeles, or Superior Court. The Superior Court has dismissed the 10 complaints covered by the settlement agreement. There are three complaints filed by approximately 125 plaintiffs who did not participate in the settlement that are still pending in the Superior Court. The plaintiffs allege that exposure to chromium at or near the Utility's compressor station at Hinkley, California caused personal injuries, wrongful deaths, or other injuries.

With respect to the unresolved claims, the Utility will continue to pursue appropriate defenses, including the statute of limitations, the exclusivity of workers' compensation laws, lack of exposure to chromium and the inability of chromium to cause certain of the illnesses alleged.

PG&E Corporation and the Utility do not expect that the outcome with respect to the remaining unresolved claims will have a material adverse effect on their financial condition or results of operations.

Delayed Billing Investigation

In February 2005, the CPUC issued a ruling opening an investigation into the Utility's billing and collection practices and credit policies. The investigation was initiated at the request of The Utility Reform Network, or TURN, after the CPUC's January 2005 decision that characterized the definition of "billing error" in a revised Utility tariff to include delayed bills and Utility-caused estimated bills as being consistent with "existing CPUC policy, tariffs and requirements." The Utility contended that prior to the CPUC's January 2005 decision, "billing error" under the Utility's former tariffs did not encompass delayed bills or Utility-caused estimated bills. The Utility petitioned the California Court of Appeals to review the CPUC's decision denying rehearing of its January 2005 decision. In December 2006, the Court of Appeals summarily rejected the Utility's petition; the Utility did not appeal that rejection to the California Supreme Court.

The CPUC's Consumer Protection and Safety Division, or CPSD, and TURN have submitted their reports to the CPUC concluding that the Utility violated applicable tariffs related to delayed and estimated bills and recommended refunds in the current amounts of approximately $54 million and $36 million, respectively, plus interest at the three-month commercial paper interest rate. The two refunds are not additive. The CPSD also recommended that the Utility pay fines of $6.75 million, while TURN recommends fines in the form of a $1 million contribution to REACH (Relief for Energy Assistance through Community Help). Both the CPSD and TURN recommend that refunds and fines be funded by shareholders.

The Utility responded that its tariff interpretation was in good faith, and was repeatedly supported by Commission staff. It argued that the CPUC should exercise its discretion not to order refunds, and that any ordered refunds should be treated in accordance with adopted ratemaking, under which the significant majority of the costs of any refunds would be reflected in future rates borne by the Utility's general body of customers. It argued that its behavior does not warrant fines or penalties. On February 15, 2007, the CPUC extended the date by which it must issue a final decision in this investigative matter to August 26, 2007.

On February 20, 2007, the administrative law judge presiding over the proceeding issued a "presiding officer" decision. Although the decision found that penalties were not warranted, the decision orders the Utility to refund, at shareholder expense, approximately $23 million to customers for "illegal backbill charges" relating to estimated and delayed bills that were charged to customers in excess of the time limits in the Utility's tariff. The decision also orders the Utility to refund reconnection fees and "pay credits to certain customers whose service was shutoff for nonpayment of illegal backbills."

Under CPUC rules, parties in an adjudicatory proceeding may appeal the presiding officer's decision within 30 days. In addition, any Commissioner may request review of the presiding officer's decision within 30 days of the date of issuance. If no appeal or request for review is filed within 30 days, the presiding officer's decision will become the final CPUC decision. The Utility intends to appeal the presiding officer's decision.

PG&E Corporation and the Utility do not expect that the outcome of this matter will have a material adverse effect on their financial condition or results of operations.

QUARTERLY CONSOLIDATED FINANCIAL DATA (UNAUDITED)

	Quarter ended			
(in millions, except per share amounts)	December 31	September 30	June 30	March 31
2006				
PG&E Corporation				
Operating revenues	**$3,206**	**$3,168**	**$3,017**	**$3,148**
Operating income	**439**	**735**	**465**	**469**
Income from continuing operations	**152**	**393**	**232**	**214**
Net income	**152**	**393**	**232**	**214**
Earnings per common share from continuing operations, basic	**0.43**	**1.09**	**0.65**	**0.61**
Earnings per common share from continuing operations, diluted	**0.43**	**1.09**	**0.65**	**0.60**
Net income per common share, basic	**0.43**	**1.09**	**0.65**	**0.61**
Net income per common share, diluted	**0.43**	**1.09**	**0.65**	**0.60**
Common stock price per share:				
High	**48.17**	**42.51**	**40.90**	**40.68**
Low	**40.72**	**39.06**	**38.30**	**36.25**
Utility				
Operating revenues	**$3,206**	**$3,168**	**$3,017**	**$3,148**
Operating income	**443**	**737**	**465**	**470**
Net income	**159**	**378**	**231**	**217**
Income available for common stock	**155**	**375**	**227**	**214**
2005(1)				
PG&E Corporation				
Operating revenues	$3,732	$2,804	$2,498	$2,669
Operating income	414	515	540	501
Income from continuing operations	180	239	267	218
Net income	180	252	267	218
Earnings per common share from continuing operations, basic	0.49	0.63	0.70	0.55
Earnings per common share from continuing operations, diluted	0.49	0.62	0.70	0.54
Net income per common share, basic	0.49	0.66	0.70	0.55
Net income per common share, diluted	0.49	0.65	0.70	0.54
Common stock price per share:				
High	40.10	39.64	37.91	36.18
Low	34.54	35.60	33.78	31.83
Utility				
Operating revenues	$3,733	$2,804	$2,498	$2,669
Operating income	418	517	540	495
Net income	187	248	276	223
Income available for common stock	183	244	272	219

(1) During the third quarter of 2005, PG&E Corporation received additional information from NEGT regarding income to be included in PG&E Corporation's 2004 federal income tax return. This information was incorporated in the 2004 tax return, which was filed with the IRS in September 2005. As a result, the 2004 federal income tax liability was reduced by approximately $19 million. In addition, NEGT provided additional information with respect to amounts previously included in PG&E Corporation's 2003 federal income tax return. This change resulted in PG&E Corporation's 2003 federal income tax liability increasing by approximately $6 million. These two adjustments, netting to $13 million, were recognized in income from discontinued operations in the third quarter of 2005.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of PG&E Corporation and Pacific Gas and Electric Company, or the Utility, is responsible for establishing and maintaining adequate internal control over financial reporting. PG&E Corporation's and the Utility's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles, or GAAP. Internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of PG&E Corporation and the Utility, (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP and that receipts and expenditures are being made only in accordance with authorizations of management and directors of PG&E Corporation and the Utility, and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of internal control over financial reporting as of December 31, 2006, based on the criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its assessment and those criteria, management has concluded that PG&E Corporation and the Utility maintained effective internal control over financial reporting as of December 31, 2006.

Deloitte & Touche LLP, an independent registered public accounting firm, has audited the Consolidated Financial Statements of PG&E Corporation and the Utility for the three years ended December 31, 2006, appearing in this annual report and has issued an attestation report on management's assessment of internal control over financial reporting, as stated in their report, which is included in this annual report on page 175.

To the Boards of Directors and Shareholders of PG&E Corporation and Pacific Gas and Electric Company

We have audited the accompanying consolidated balance sheets of PG&E Corporation and subsidiaries (the "Company") and of Pacific Gas and Electric Company and subsidiaries (the "Utility") as of December 31, 2006 and 2005, and the related consolidated statements of income, cash flows and shareholders' equity of the Company and of the Utility for each of the three years in the period ended December 31, 2006. These financial statements are the responsibility of the respective managements of the Company and of the Utility. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits 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. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the respective consolidated financial position of the Company and of the Utility as of December 31, 2006 and 2005, and the respective results of their consolidated operations and their cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 of the Notes to the Consolidated Financial Statements, in 2006 the Company and the Utility adopted new accounting standards for defined benefit pensions and other postretirement plans and share-based payments. In December 2005, the Company and the Utility adopted a new interpretation of accounting standards for asset retirement obligations. During March 2004, the Company changed the method of computing earnings per share.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's and the Utility's internal control over financial reporting as of December 31, 2006, based on the criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 21, 2007 expressed an unqualified opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting and an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

DELOITTE & TOUCHE LLP

San Francisco, California
February 21, 2007

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Boards of Directors and Shareholders of PG&E Corporation and Pacific Gas and Electric Company

We have audited management's assessment, included in the accompanying *Management's Report on Internal Control Over Financial Reporting*, that PG&E Corporation and subsidiaries (the "Company") and Pacific Gas and Electric Company and subsidiaries (the "Utility") maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's and the Utility's management is responsible for maintaining effective internal control over financial reporting and for their assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's and the Utility's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audits included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that the Company and the Utility maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Company and the Utility maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on the criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) the consolidated financial statements and financial statement schedules as of and for the year ended December 31, 2006 of the Company and the Utility and our report dated February 21, 2007 expressed an unqualified opinion on those financial statements and financial statement schedules and included an explanatory paragraph relating to accounting changes.

DELOITTE & TOUCHE LLP

San Francisco, California
February 21, 2007

CORPORATE GOVERNANCE

The following documents are available in the Corporate Governance section of PG&E Corporation's website, **www.pgecorp.com**, or Pacific Gas and Electric Company's website, **www.pge.com/about_us**:

- PG&E Corporation's and Pacific Gas and Electric Company's codes of conduct and ethics that apply to each company's directors and employees, including executive officers,
- PG&E Corporation's and Pacific Gas and Electric Company's Corporate Governance Guidelines, and
- Charters of key Board committees, including charters for the companies' Audit Committees, Executive Committees, the PG&E Corporation Finance Committee, the PG&E Corporation Nominating, Compensation, and Governance Committee, and the PG&E Corporation Public Policy Committee.

Shareholders also may obtain print copies of these documents by sending a written request to:

Linda Y.H. Cheng
Vice President, Corporate Governance and
Corporate Secretary
One Market, Spear Tower
Suite 2400
San Francisco, CA 94105-1126

On May 16, 2006, Peter A. Darbee, Chairman of the Board, Chief Executive Officer, and President of PG&E Corporation submitted an Annual CEO Certification to the New York Stock Exchange and NYSE Arca, Inc., formerly the Pacific Exchange, certifying that he was not aware of any violation by PG&E Corporation of the respective stock exchange's corporate governance listing standards.

BOARDS OF DIRECTORS OF PG&E CORPORATION AND PACIFIC GAS AND ELECTRIC COMPANY(1)

DAVID R. ANDREWS
Senior Vice President, Government Affairs, General Counsel, and Secretary, Retired, PepsiCo, Inc.

LESLIE S. BILLER
Vice Chairman and Chief Operating Officer, Retired, Wells Fargo & Company

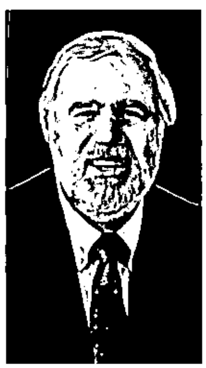
DAVID A. COULTER
Managing Director and Senior Advisor, Warburg Pincus LLC

C. LEE COX
Vice Chairman, Retired, AirTouch Communications, Inc. and President and Chief Executive Officer, Retired, AirTouch Cellular

PETER A. DARBEE
Chairman of the Board, Chief Executive Officer, and President, PG&E Corporation and Chairman of the Board, Pacific Gas and Electric Company

MARYELLEN C. HERRINGER
Attorney-at-Law

THOMAS B. KING(1)
Chief Executive Officer, Pacific Gas and Electric Company and Senior Vice President, PG&E Corporation



RICHARD A. MESERVE
President, Carnegie Institution of Washington

MARY S. METZ
President, Retired, S. H. Cowell Foundation

BARBARA L. RAMBO
Vice Chairman, Nietech Corporation

BARRY LAWSON WILLIAMS
President, Williams Pacific Ventures, Inc.

(1) The composition of the Boards of Directors is the same, except that Thomas B. King is a member of the Pacific Gas and Electric Company Board of Directors only.

PERMANENT COMMITTEES OF THE BOARDS OF DIRECTORS OF PG&E CORPORATION AND PACIFIC GAS AND ELECTRIC COMPANY[1]

EXECUTIVE COMMITTEES

Subject to certain limits, may exercise the powers and perform the duties of the Boards of Directors.

Peter A. Darbee, *Chair*
David A. Coulter
C. Lee Cox
Thomas B. King[1]
Mary S. Metz
Barry Lawson Williams

AUDIT COMMITTEES

Review financial and accounting practices, internal controls, external and internal auditing programs, business ethics, and compliance with laws, regulations, and policies that may have a material impact on the Consolidated Financial Statements. Satisfy themselves as to the independence and competence of the independent registered public accounting firm, select and appoint the independent registered public accounting firm to audit PG&E Corporation's and Pacific Gas and Electric Company's accounts and internal control over financial reporting, and pre-approve all audit and non-audit services provided by the independent registered public accounting firm.

Barry Lawson Williams, *Chair*
David R. Andrews
Maryellen C. Herringer
Mary S. Metz

FINANCE COMMITTEE

Reviews financial and capital investment policies and objectives and specific actions required to achieve those objectives, long-term financial and investment plans and strategies, annual financial plans, dividend policy, short-term and long-term financing plans, proposed capital projects, proposed divestitures, strategic plans and initiatives, major commercial and investment banking, financial consulting, and other financial relationships, and risk management activities. Annually reviews a five-year financial plan that incorporates PG&E Corporation's business strategy goals, as well as an annual budget that reflects elements of the approved five-year plan.

David A. Coulter, *Chair*
Leslie S. Biller
C. Lee Cox
Barbara L. Rambo
Barry Lawson Williams

NOMINATING, COMPENSATION, AND GOVERNANCE COMMITTEE

Recommends candidates for nomination as directors and reviews the composition, performance, and compensation of the Boards of Directors. Reviews corporate governance matters, including the Corporate Governance Guidelines of PG&E Corporation and Pacific Gas and Electric Company. Reviews employment, compensation, and benefits policies and practices, and long-range planning for executive development and succession.

C. Lee Cox, *Chair*
David A. Coulter
Barbara L. Rambo
Barry Lawson Williams

PUBLIC POLICY COMMITTEE

Reviews public policy issues that could significantly affect the interests of customers, shareholders, or employees, policies and practices with respect to those issues, including but not limited to improving the quality of the environment, charitable activities, equal opportunity, and significant societal, governmental, and environmental trends and issues that may affect operations.

Mary S. Metz, *Chair*
David R. Andrews
Leslie S. Biller
Maryellen C. Herringer
Richard A. Meserve

(1) Except for the Executive and Audit Committees, all committees listed above are committees of the PG&E Corporation Board of Directors. The Executive and Audit Committees of the PG&E Corporation and Pacific Gas and Electric Company Boards have the same members, except that Thomas B. King is a member of the Pacific Gas and Electric Company Executive Committee only.

PG&E CORPORATION OFFICERS

PETER A. DARBEE
Chairman of the Board,
Chief Executive Officer, and President

LESLIE H. EVERETT
Senior Vice President,
Communications and Public Affairs

KENT M. HARVEY
Senior Vice President and
Chief Risk and Audit Officer

RUSSELL M. JACKSON
Senior Vice President, Human Resources

CHRISTOPHER P. JOHNS
Senior Vice President,
Chief Financial Officer, and Treasurer

THOMAS B. KING
Senior Vice President

HYUN PARK
Senior Vice President and General Counsel

RAND L. ROSENBERG
Senior Vice President,
Corporate Strategy and Development

LINDA Y.H. CHENG
Vice President, Corporate Governance
and Corporate Secretary

STEVEN L. KLINE
Vice President, Corporate
Environmental and Federal Affairs

G. ROBERT POWELL
Vice President and Controller

RICHARD I. ROLLO
Vice President, Strategic Development
and Business Integration

GABRIEL B. TOGNERI
Vice President, Investor Relations

JAMES A. TRAMUTO
Vice President,
Federal Governmental Relations

PACIFIC GAS AND ELECTRIC COMPANY OFFICERS

PETER A. DARBEE
Chairman of the Board

THOMAS B. KING
Chief Executive Officer

WILLIAM T. MORROW
President and Chief Operating Officer

THOMAS E. BOTTORFF
Senior Vice President,
Regulatory Relations

HELEN A. BURT
Senior Vice President and
Chief Customer Officer

JEFFREY D. BUTLER
Senior Vice President, Energy Delivery

RUSSELL M. JACKSON
Senior Vice President, Human Resources

CHRISTOPHER P. JOHNS
Senior Vice President,
Chief Financial Officer, and Treasurer

JOHN S. KEENAN
Senior Vice President,
Generation and Chief Nuclear Officer

OPHELIA B. BASGAL
Vice President, Civic Partnership and
Community Initiatives

JAMES R. BECKER
Vice President, Diablo Canyon Power
Plant Operations and Station Director

LINDA Y.H. CHENG
Vice President, Corporate Governance
and Corporate Secretary

BRIAN K. CHERRY
Vice President, Regulatory Relations

DEANN HAPNER
Vice President, FERC and ISO Relations

WILLIAM H. HARPER, III
Vice President, Strategic Sourcing and
Operations Support

SANFORD L. HARTMAN
Vice President and
Managing Director, Law

ROBERT T. HOWARD
Vice President,
Gas Transmission and Distribution

DONNA JACOBS
Vice President, Nuclear Services

ROY M. KUGA
Vice President, Energy Supply

PATRICIA M. LAWICKI
Vice President and
Chief Information Officer

NANCY E. MCFADDEN
Vice President, Governmental Relations

DINYAR B. MISTRY
Vice President, State Regulation

G. ROBERT POWELL
Vice President and Controller

STEWART M. RAMSAY
Vice President, Asset Management and
Electric Transmission

KIMBERLY R. WALSH
Vice President, Communications

FONG WAN
Vice President, Energy Procurement

PG&E Corporation.

END