PG&E CORPORATION ANNUAL REPORT 2007

A BETTER TOMORROW

OUR JOURNEY TO BECOME THE LEADING UTILITY STARTS ANEW EVERY DAY WITH THE QUESTION: WHAT MUST WE DO TO BE BETTER TOMORROW THAN WE WERE YESTERDAY?

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A LETTER TO OUR STAKEHOLDERS

Better tomorrow than we were yesterday. Wrapped in this simple maxim is a challenge, an aspiration, a mantra, a game plan, and a commitment. It is the spirit in which we will work to provide a higher-quality customer experience in the next 24 hours, and a cleaner and more secure energy future over the next generation. It is a standard to which we hold ourselves as a company and as 20,000 individuals. And it is a path to advance our vision of building the leading utility in the United States in the eyes of customers, employees, and shareholders.

Building the Leading Utility

This ambition continued to inspire and motivate us last year — even as a number of challenges reminded us just how high we have chosen to set the bar for ourselves.

Make no mistake. We continue to think and act boldly in response to the changes we see around us. New environmental, economic, and social dynamics are reshaping customers' sensibilities around energy and, thus, their basic expectations of energy companies.

No other trend has more profound future implications for our business. We believe that the strategies that guaranteed results for utilities in the 20th century will not necessarily yield the best returns in the 21st. And it is our readiness to embrace change and begin cultivating new opportunities amid these emerging trends that will determine our ability to harvest new value for customers and shareholders in the long run.

> "We believe that PG&E Corporation continues to offer investors a highly attractive balance of solid earnings growth and risk."

We are passionate about leading this transition in the industry. Indeed, we have been among the first-movers in a number of areas with the potential to change the way energy is produced, delivered, and consumed.

But as we look ahead, we always remember that for our vision to have legs, we will have to remain consistently sure-footed in our daily execution on the fundamentals.

Operational excellence — safety, quality control, on-time and on-budget performance, getting the job done right the first time — will always be the prerequisite for reaching higher. This is why our strategy over the past few years has revolved so much around revamping PG&E's core systems and processes to be better, faster, and more cost-effective.

We made strides in this effort again last year. The seamless execution of a complex IT upgrade to improve our customer care and billing capabilities was one example. Record operating results at the Diablo Canyon Power Plant was another. Exceeding our savings goals from supply chain improvements was yet another. Combined with progress on safety and reducing the number of outages and work errors, these and other accomplishments make the case for a solid year in operations.

However, these positives were clouded by the fact that in some other important areas, we finished the year behind our goals.

Most significant, we did not reap all of the expected operational and financial benefits from the reconfigurations to our service delivery model. Taking this into account, these and other process and systems improvements will still yield about $1 billion of future savings, but this is less than anticipated.

Also, the switch to new systems temporarily slowed down our workflow and frustrated employees and customers. A top priority in 2008 is resolving these issues and identifying and pursuing new opportunities. Our mantra compels us to continuously improve. We are at work on this now. We know that one key is doing more to engage our union field teams, together with cross-functional management teams, in the brainstorming and piloting of new ideas. I'm confident that together we will succeed.

Adding to last year's headwinds were surging costs for certain materials and equipment. As a result of global demand, prices have continued to rise quickly.

And lastly, as we have probed deeper into the needs surrounding system reliability, we recognized last year that even more new capital will be necessary to achieve the levels of performance we and our customers expect.

Our operating plan for 2008 confronts these factors head-on.

We have reprioritized the change initiatives planned for 2008, giving the green light only to those with the potential for the greatest returns in efficiencies and savings. We are focusing meticulously on execution and productivity. This includes assessing our staffing and instituting new and increasingly rigorous measures and structure around managing our resources. And we boosted our four-year capital plan by $2.2 billion.

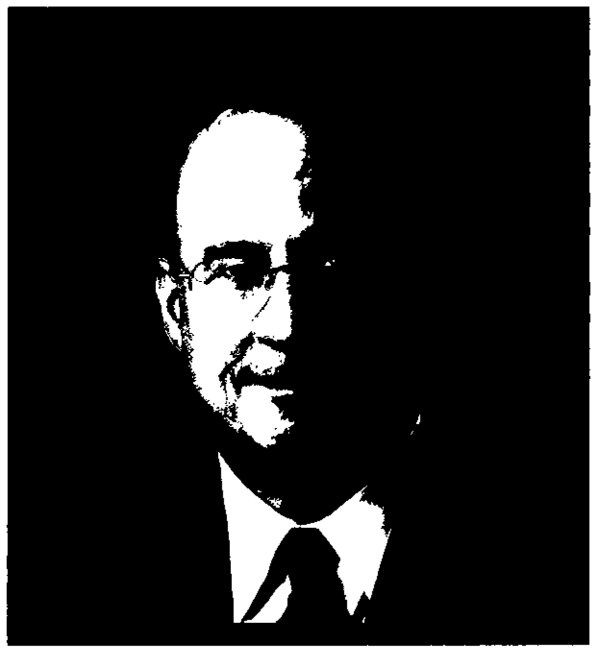
Fulfilling Our Commitment to Investors

Ensuring that PG&E Corporation continues to be an attractive long-term investment is fundamental to everything we seek to achieve.

On a non-GAAP earnings from operations basis, which excludes items that are considered to be non-operating, earnings per share for 2007 rose by 8 percent over 2006, to $2.78 per share. This met the upper part of our target range and was in line with commitments to Wall Street. Total net income was $1 billion, as reported under GAAP. (The table on page 31 explains the comparison of GAAP total net income and non-GAAP earnings from operations.) We also increased our common stock dividend by 9 percent last year, and announced another 8 percent increase in February this year.

Judged in terms of total shareholder return, however — stock price appreciation plus dividends — last year's results were less than satisfying. After total returns of 15 percent in 2005 and 31 percent in 2006, shareholders saw some of these gains offset by a decline in the share price in 2007.

In December, we reaffirmed our existing commitment to grow earnings per share from operations at a compound average annual rate of 8 percent for 2007 through 2011. However, we also acknowledged that in part due to the challenges mentioned earlier, some earnings opportunities that previously represented potential upside to our targets could no longer be seen as such. Instead, these opportunities are included in the 8 percent growth we have targeted to deliver.



PG&E's target earnings growth rate still places the company among the top 25 percent of comparable utilities. Within this group, we believe that PG&E Corporation continues to offer investors a highly attractive balance of solid earnings growth and risk. Among other factors, this reflects a robust slate of already-approved capital investments and a high degree of alignment between our strategy and the priorities of California policy makers.

Improving Customer Satisfaction

We improved PG&E's customer satisfaction significantly in 2007, extending a positive trend from the past two years.

J.D. Power and Associates ranked PG&E's business customer satisfaction in the top 10 percent of utilities nationwide for both gas and electric service. The same was true of residential gas customer satisfaction, where we finished fifth in the nation, up from 20th place in 2006. In the one area where customers rated us slightly under the average, namely residential electric service, we still made notable progress.

Behind these results were a number of improvements. For example, we increased our success rate for resolving customer issues on the first service visit. We also sped up issue resolution times by 50 percent.

One area in which we fell short of expectations, however, was improving our timeliness in connecting new customers to the grid. Intensive attempts to resolve this situation last year did not deliver as we had hoped. We will continue to devote resources to this issue until we have it fixed.

In addition to better, faster, and more cost-effective service, new products and services are also driving customer satisfaction.

Last year, for example, we launched ClimateSmart™, the nation's first program to allow utility customers to voluntarily offset greenhouse gases associated with their energy use. To date, 18,000 have signed up.

We also continued to enhance our highly successful winter gas savings program. In 2007, about 1.9 million customers earned a bill credit of up to 20 percent by reducing their year-over-year winter gas usage.

And on a smaller, but no less important scale, we've made it more convenient for customers by improving our customer website and adding online offerings like paperless billing and electronic bill payment. In fact, in a survey of 111 utilities last year, E Source, an independent research group, ranked PG&E's website best in the industry, citing its customer friendliness.

Strengthening Our Infrastructure

One certainty in the utility business is that our service to customers can only be as good as our system. Last year, we made substantial capital investments to improve the reliability and capacity of our infrastructure. These investments are critical to achieving our vision. They are also the primary driver for earnings growth, as we earn additional returns on an expanding asset base.

In 2007, capital investments totaled $2.8 billion. Total capital investment for the 2008 through 2011 time frame is now expected to be $13.5 billion, one of the largest capital programs in the industry.

In 2008, we expect to expand local electric and gas distribution networks to connect 65,000 new electric customers and 51,000 new gas customers. We'll also continue upgrading and replacing hardware such as cables, transformers, and gas pipeline to increase reliability. And we'll continue to look at ways to integrate new technology and protective equipment into our system, enhancing capabilities to limit the scope of power outages and restore service more quickly.

Over the next several years, spending on electric transmission will ramp up considerably. This will support the construction of new lines to accommodate renewable energy deliveries and to address regional power needs.

For example, last year we unveiled plans to build a new transmission line along the Fresno-Bakersfield corridor. Dubbed the Central California Clean Energy Transmission Line, it would increase power supplies in the region by creating better access to sources of solar, wind, and geothermal energy.

Additional natural gas supplies are also critical to California's future. We recently signed an agreement to bring in new supplies of competitively priced gas to California from the Rocky Mountains.

On the electric generation front, in addition to ongoing investment in our existing hydroelectric and nuclear facilities, we moved forward on three new power plants that will be vital to our long-term resource plan.

Very importantly, information technology is becoming an increasingly central element in our infrastructure. The "smart" grid of the future will rely heavily on computer technology and digital communications. Our multi-billion dollar investment in SmartMeter™ devices is one initiative putting us at the forefront of this evolution. In fact, *InformationWeek* magazine named PG&E the top energy company for IT innovation — and one of the top 40 companies overall — in its 2007 "*InformationWeek* 500" ranking.

Setting the Foundations for a Sustainable Energy Future

The immediacy and the enormity of the challenge we face in global warming became even more stark in 2007. Multiple new studies showed that warming is changing the planet more rapidly and severely than previously forecast.

We believe the imminent and urgently needed reckoning with greenhouse gas emissions is likely to significantly and permanently change the utility business. A carbon-constrained future is no longer a question of if, but rather when and how. PG&E is urging policy makers to act now, with a focus on creating national laws that limit greenhouse gases and impose a market price on carbon emissions.

Equally important, we are taking action in the meantime to prepare our company and our customers for this future. This includes continuing to aggressively drive advances in energy efficiency and extending our renewable energy commitments.

This leadership has put PG&E in a strong position. Last year, Innovest Strategic Value Advisors, a top evaluator of investor risk and value related to sustainability issues, issued a report that ranked PG&E's environmental leadership (EcoValue index) in the top 25 percent of all utilities in its peer group.

Through energy efficiency, we plan to meet 50 percent or more of the growth in energy demand in our service area over the next 10 years. Importantly, this also now represents a significant earnings opportunity. An estimated $100 million to $200 million in total incentives are available to PG&E over the next four years if we meet California's energy savings targets, which are the nation's highest.

> "On average, over 50 percent of the energy PG&E currently supplies comes from sources that emit no greenhouse gases."

Our team is excited about these opportunities. They make economic sense for our customers, and provide utilities with strong incentives to pursue energy efficiency as an alternative to building new power plants.

Demand response is another priority. Reducing peak energy demand is one of the biggest keys to lowering emissions, reducing costs, and improving overall efficiency.

Last year, we created a new SmartAC™ program that pays customers who choose to allow PG&E to remotely adjust their air conditioners at peak times. We aim to enroll over 400,000 customers, allowing us to cut demand by as much as the output of several "peaking" power plants.

In the future, our SmartMeter™ infrastructure will open up remarkable potential to expand capabilities like this in even more dramatic ways. And as the first utility to employ this technology on such a large scale, we believe our customers will be among the first to benefit from new incentive pricing structures and precision energy management tools.

On average, over 50 percent of the energy PG&E currently supplies already comes from sources that emit no greenhouse gases. These include our hydroelectric system and the Diablo Canyon nuclear power plant.

Last year we also took additional steps to increase the supply of renewable energy that will be available to our customers in the future. Already one of the nation's largest buyers of renewable energy, in 2007, PG&E signed eight new renewable energy contracts, adding over 2,700 gigawatt-hours of annual supply. These included some of the largest agreements yet for utility-scale concentrating-solar power, and, more recently, the first agreement to purchase wave energy generated by the Pacific Ocean. With these future commitments, we are on track to meet the state's renewable energy goals.

Our activities also include reducing the impacts of our own operations. For example, we are seeking to sharply reduce energy use in PG&E's data centers. Within our utility fleet, our teams are test-driving a number of cleaner vehicles, including a hybrid bucket truck and plug-in hybrid sport utility vehicles. And we are offsetting the carbon emissions associated with the energy used at all of our office facilities throughout the state.

Staying Faithful to Our Vision

Entering 2008, we know we have work to do in order to recapture the momentum that has carried us so far in the past few years. Our team shares this understanding. We know what it requires, and we are holding ourselves accountable for delivering it.

Above all, we remain absolutely committed to — and confident in — our vision of becoming the leading utility. The broader trends in the industry and the economy only reaffirm that our future depends on our ability to evolve with — or ahead of — the forces changing our business.

As I recently heard it said, the best way to predict the future is to create it. That's what we are working to do today.

It is why we undertook a transformation effort more sweeping than any other utility.

It is why we are remaking our culture to operate with the mindset of a competitive company.

It is why we are embracing and experimenting with new technology more quickly and extensively than ever.

It is why we have been among the first to spark a national conversation on climate change among business leaders.

It is why we have recruited — and been able to attract — highly talented new additions to our team.

And it is why I believe that PG&E is poised better than any other utility to take advantage of the opportunities ahead.

We know of no better way to drive toward this result than to keep our sights on being the leader in the business — and you can count on us to continue doing so.

Sincerely,

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

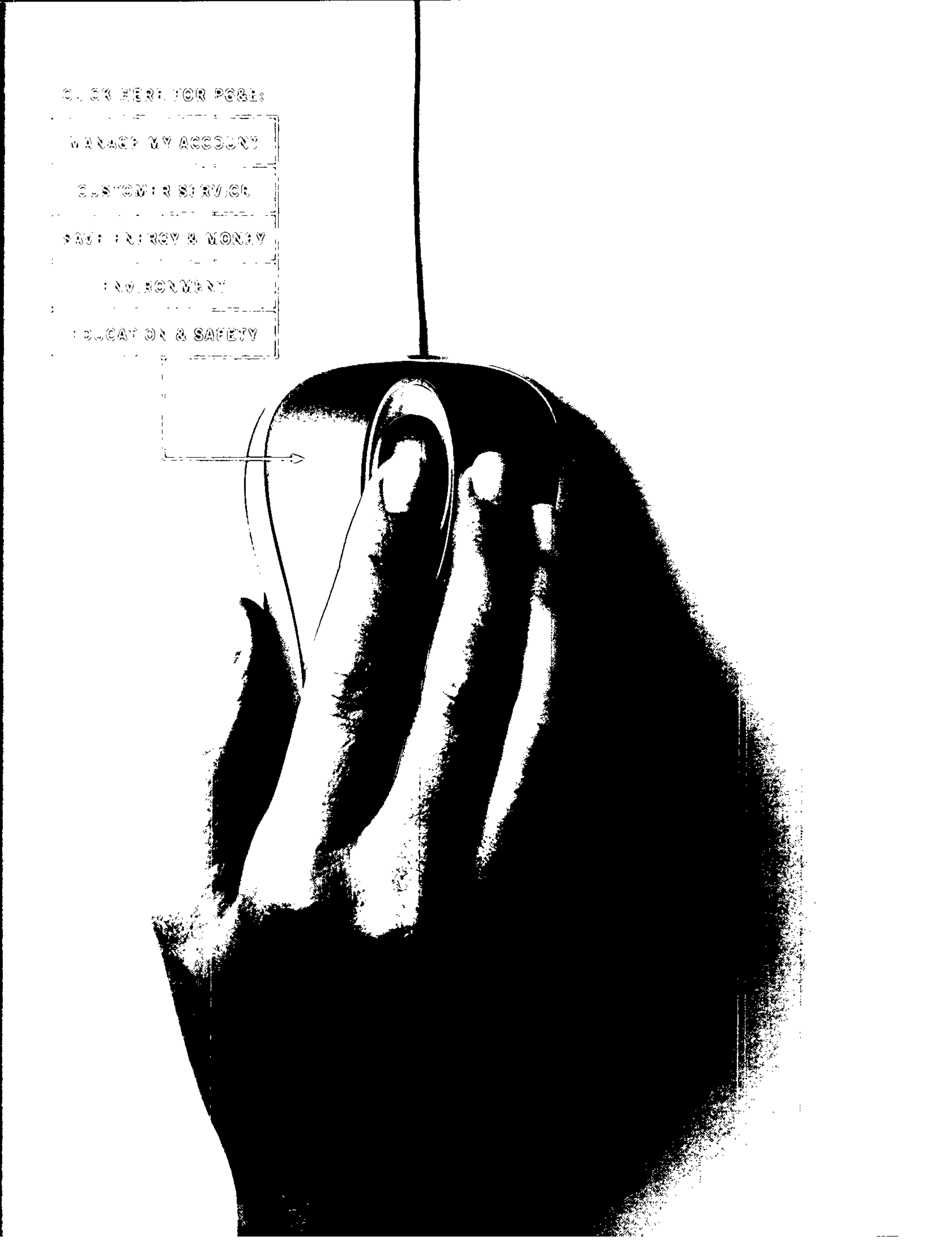
March 10, 2008

WHAT MAKES A BETTER TOMORROW?

A better tomorrow is a company that's always **Easy** for customers to do business with. It's a stronger gas and electric system that's delivering **Dependable** service 24/7, and wise investments to ensure that future generations will have the energy they need. It's new ways to ensure the **Smart**, efficient use of our energy supplies and new technologies to power our future. It's more **Sustainable** energy from clean renewable energy resources such as solar, wind, and waves to address global warming and other environmental challenges. It's being ever more **Connected** to our communities through 20,000 employees and many partnerships to help the growth and well-being of the diverse places where we work and live. It's realizing our vision of becoming the leading utility in the United States.

EASY

Is it possible to love your gas and electric company? Most utilities would think this is a crazy question. We embraced it as a challenge and set a goal to delight our customers. Customers today are busier and more stretched than ever. We know that a smooth and satisfying customer experience is one of the best ways for us to provide them with real value. One of the places we are starting is finding ways to make it easier to do business with PG&E. Accordingly, at virtually every major touch point with customers, we are asking how service can be quicker, clearer, cheaper, cleaner, more convenient, or—ideally—all of the above.


CLICK HERE FOR PG&E:
MANAGE MY ACCOUNT
CUSTOMER SERVICE
SAVE ENERGY & MONEY
ENVIRONMENT
EDUCATION & SAFETY

EASY With 15 million customers living and working across one of the nation's most diverse regions, there is, of course, no one-size-fits-all approach to service. So we work to understand and respond as best we can to the unique needs of our different customers.

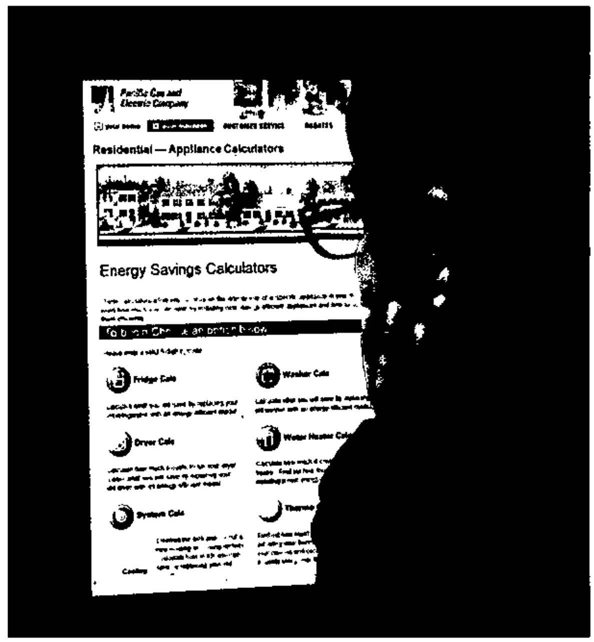
Expanding online service options is one example. In one industry study last year, PG&E's website was named the best in the business for customer friendliness. We now offer customers greater online visibility into their accounts. We have also introduced more flexible payment options like using a checking account or Visa debit card to settle their accounts. In J.D. Power and Associates' surveys of customer satisfaction last year, PG&E was a leader among utilities whose customers are taking advantage of the convenience of paying bills via the Internet.

PG&E introduced a successful pilot program last year to offer customers time- and cost-saving appliance repairs that previously had to be referred to third-party repair people.

In customers' homes, we are also enhancing the services our technicians are able to provide. Last year we successfully piloted a program that lets PG&E gas service representatives take care of simple repairs and parts replacements on certain gas appliances that previously would have been referred to a third party, meaning more hassle for the customer and another visit from PG&E after the work was complete. Now, we can resolve minor problems immediately, complete the job, and avoid the added time and expense of a second visit. The fee for this optional service covers parts, labor, and other program expenses.

It's also easier for customers to get the information they want when our crews are working to restore service after storms or other service disruptions. Customers can elect to receive phone updates on expected restoration times and even sign up to receive a morning wake-up call if an outage threatens to run through the night.

PG&E's award-winning website puts a full suite of valuable tools and services at customers' fingertips, including the ability to find and quantify potential energy savings or better understand their carbon footprint.



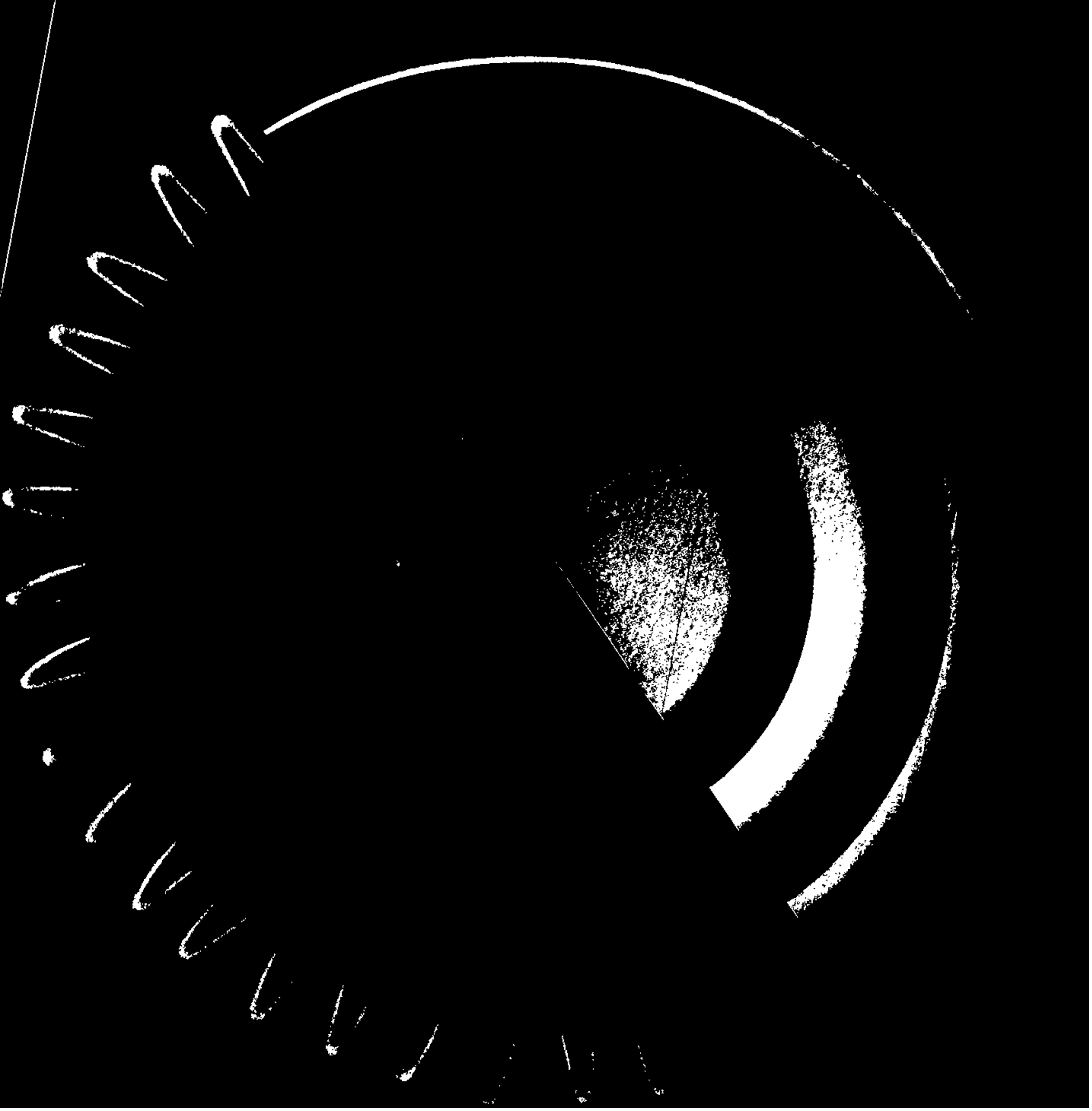
One of the many benefits of our SmartMeter™ technology will be that customers will be able to start and stop service faster, as the meter's two-way communication capabilities will allow PG&E to make these changes remotely.

Other examples of ways we are working to make it easier for our customers include assisting callers in over 100 different languages at our call centers, as well as offering Spanish and Chinese versions of pge.com.

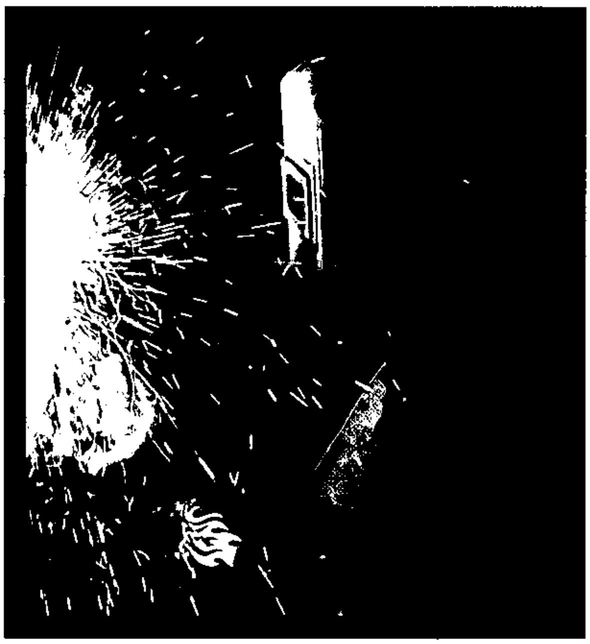
We know we have a long way to go before we can say that we are delighting every customer. But our customer satisfaction ratings show we are gaining ground, and we expect to continue doing so in 2008.

DEPENDABLE

Customers large and small count on PG&E to be there every time they flip the switch or turn up the thermostat. In fact, they count on us to be years ahead of the game—not just delivering today, but also planning for their future needs. This entails making economically and environmentally responsible investments in our wires, pipes, and other infrastructure and lining up affordable and adequate energy supplies along the way. Our teams are at work on this challenge every day. We understand the importance of the responsibilities we are entrusted with in these areas, and we are committed to doing whatever it takes to meet them in ways that support our vision to be the leading utility.



DEPENDABLE In the high-tech economy, customer needs and expectations for reliable energy are greater than ever. PG&E is pursuing one of the industry's largest multi-year capital investment programs to support growth and improve reliability in northern and central California. We plan to invest $13.5 billion in our system over the 2008 through 2011 time frame. Additions to our infrastructure will include new highly efficient power plants, new gas and electric transmission lines to serve fast-growing areas in the Central Valley and access renewable energy supplies, and new and upgraded equipment for our neighborhood gas and electric distribution networks.



Construction began last year on PG&E's first new power plant in nearly 20 years. The state-of-the-art Gateway Generating Station near the San Francisco Bay Area will supply enough power for nearly 400,000 customers.

We operate one of the nation's largest electric and gas distribution systems, serving the world's sixth-largest economy. This year we will expand this system to take care of 116,000 new customers. In 2007, we put in 17 new substation transformer banks, which enabled us to supply power to more than 530,000 customers. We also built 39 new distribution circuits and replaced 2,980 distribution transformers to serve rising demand from a growing population.

Additional projects are under way or planned throughout our service area. One of the largest is a new

$27 million transmission line to add reliability and capacity for 60,000 more customers on the power system serving the growing cities of Napa and Sonoma. Another is a $15 million investment to substantially boost power capacity to our customers in Butte, Yuba, and Sutter counties in rural northern California.

PG&E's 160,000 miles of power lines and 46,000 miles of gas pipelines deliver energy to 15 million Californians over 70,000 square miles. PG&E is investing $13.5 billion in its system from 2008 through 2011.

We are also investing in our power generation assets. This year our Diablo Canyon nuclear plant is moving ahead with replacement of its massive steam generators. The $700 million project will ensure the plant is capable of continuing to provide emissions-free power for over two million California homes.

PG&E's work in this area doesn't end with the capital investments. Our teams are needed to keep these systems running safely and reliably 24/7. Their commitment to operational excellence is centered today in maintaining our system with an ever-increasing focus on better training and improving the quality of our work, designing our systems to be stronger and more flexible, restoring service more quickly when nature strikes or equipment breaks down, and connecting new homes and businesses to the grid more quickly.

SMART

Helping consumers use less energy sounds like a losing business proposition for a utility. We see it differently. Empowering customers with the know-how and technologies to become smarter energy users is an increasingly important source of value. PG&E has the potential to earn $100 million to $200 million in incentives in the next four years if it helps customers successfully achieve aggressive energy-savings targets. This not only saves money, it is also one of the most effective and economic ways to cut greenhouse gases. PG&E's energy efficiency programs over the past 30 years have saved customers $22 billion and kept over 135 million tons of carbon out of the skies, while our company and California's economy have flourished.


IQ

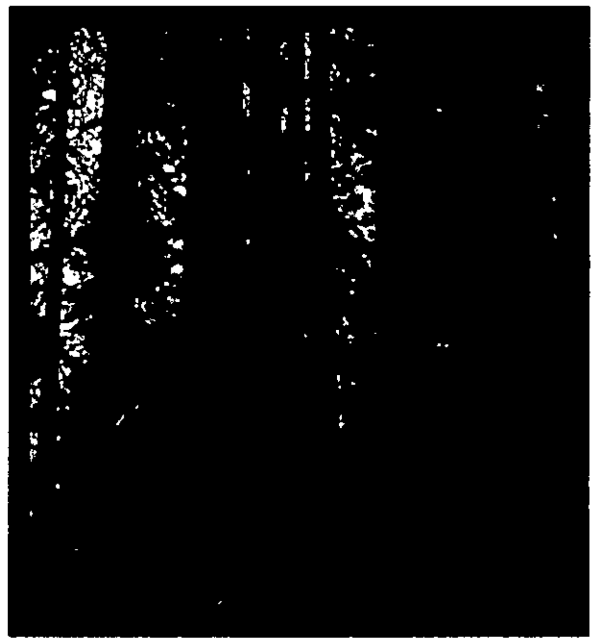
SMART We plan to meet 50 percent or more of the growth in energy demand in PG&E's service area over the next decade through driving smarter energy use. This includes giving customers the tools and information to better manage their energy use, finding ways to advance more efficient technologies, and changing energy use patterns to provide major advantages in the effort to reduce environmental impacts.

PG&E is leading the utility industry in the drive to harness energy savings from computers, and partnered last year with IBM to significantly reduce energy use in our San Francisco Data Center.

Last year, for example, we announced our intention to upgrade the high-tech gas and electric meters we are currently installing for all customers. The digital communications capabilities in the new devices create opportunities to provide the information and incentives customers need to be more efficient. It also will provide them unprecedented control, with the ability to remotely operate appliances or set their thermostat. Combined with new pricing options, this technology can substantially cut peak power demand.

A wealth of similarly promising technologies are under development today. Helping the best of these break into the market is one reason PG&E created an Emerging Technologies Program. PG&E is helping shepherd over 60 different innovations in partnership with leading universities, technology companies, research organizations, venture capital firms, and other utilities. Among them are technologies for automating energy management for buildings, improving home air conditioner efficiency and lighting classrooms with solar tubes.

Last year, nearly 15,000 customers joined ClimateSmart™, the first utility program giving them a choice to be carbon neutral by supporting sound investments to preserve California forests, which store carbon dioxide.



We also continue to be highly successful working with leaders like IBM, HP, Google, and Sun on energy efficient computing. For example, we created the first incentive programs to drive sales of energy efficient servers. We also provide incentives for computer manufacturers to incorporate more energy-saving components like efficient power supplies or software that lets computers snooze when not in use.

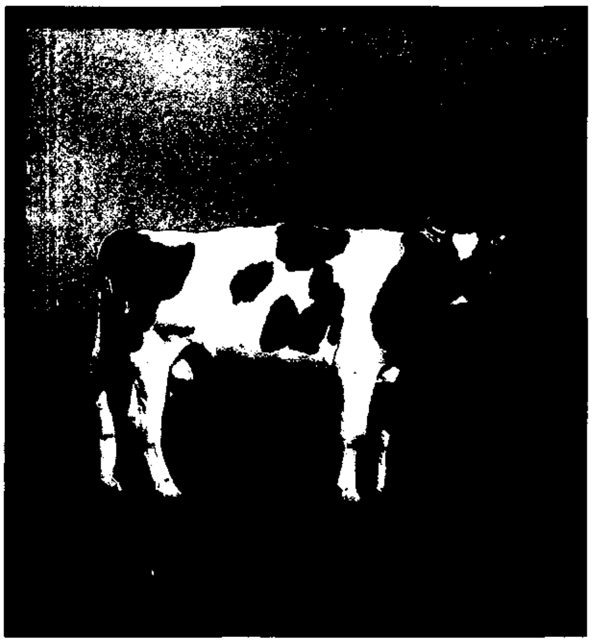
But not all energy efficiency improvements require new technology. Simple things like compact fluorescent bulbs can have a profound impact. We are aggressively encouraging the use of CFLs by helping manufacturers lower prices, and by raising awareness through advertising and campaigns like our giveaway of one million CFLs during National Energy Awareness Month last October. These free CFLs alone could collectively save the amount of energy needed to power 60,000 homes.

SUSTAINABLE

Finding ways to produce and use energy sustainably may be the single most important global challenge of the next 50 to 100 years. If the best thinking of our leading scientists today is correct, the future of the planet is at stake. Becoming smarter energy users is one essential piece of the solution. But producing clean, cost-effective energy from new sources is undoubtedly another. On average, more than half of the electricity PG&E delivers already comes from carbon-free sources, including our own hydroelectric and nuclear facilities. We are also one of the nation's largest buyers of renewable energy. And we have helped customers connect more solar installations to the grid than any other utility. But even this is only a beginning.

SUSTAINABLE PG&E is increasing the supplies of renewable power available to our customers at an unprecedented pace. California has set one of the highest targets in the country for the portion of the state's power that comes from renewable sources. We supported this target, and we are on track to achieve it.

Last year, we announced a number of watershed agreements with suppliers, providing the catalyst for the construction of new renewable energy facilities. In total, these contracts committed PG&E to new future purchases of 1,024 megawatts. These ranged from well-established sources like wind and geothermal energy to upstart technologies designed to tap remarkable new sources of power, like wave power from proposed facilities off the California coast.



PG&E is working with innovative companies and California dairy farmers to capture methane from large California dairy farms and turn it into a new source of clean, renewable natural gas for the benefit of our customers and the environment.

For example, our purchase commitments are driving the construction of utility-scale concentrating-solar facilities in the Mojave desert, including the largest single commitment for concentrating-solar energy to date. This technology uses concentrated heat from the sun to drive conventional steam generators. PG&E is also pioneering the use of pipeline-quality natural gas using biomethane from cow waste and other organic materials.

Tapping into this resource from California's agricultural sector may offer utility-scale volumes of renewable natural gas. We are already purchasing some of this resource through agreements approved last year. And we recently announced our interest in the potential expansion of this resource.

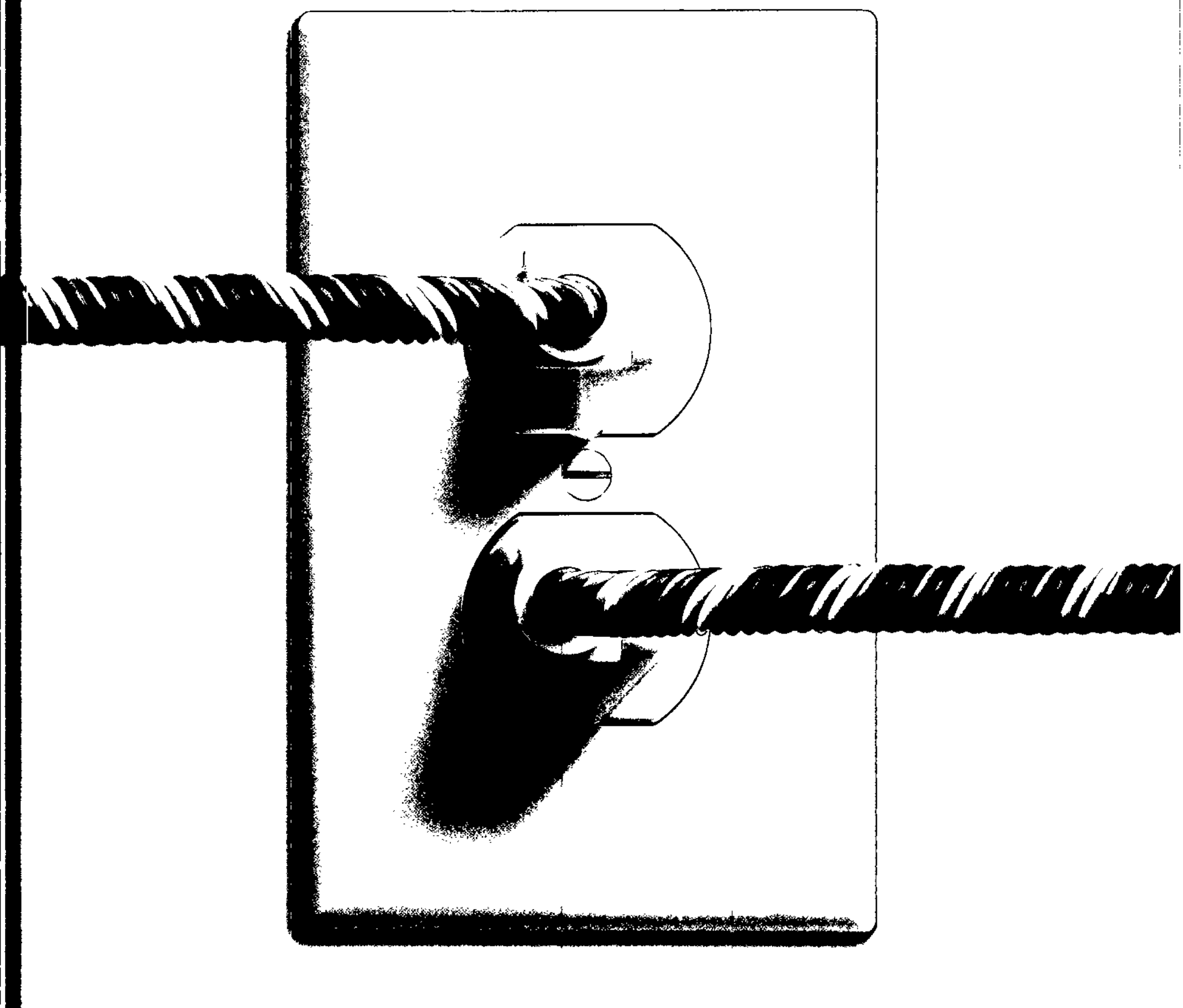
Possibilities involving the intersection of the energy and transportation sectors are also exciting. Plug-in electric hybrid cars could some day offer an opportunity to supply clean power back to the grid at times when high demand for power might require using more carbon-intensive generation. PG&E is one of a number of companies exploring this technology. Last year, we partnered with Google in Silicon Valley to demonstrate a plug-in hybrid vehicle.

Under a contract signed last year, the Mojave Solar Park will deliver enough energy to PG&E to power 400,000 homes. The project, to be built in California's Mojave Desert, will be one of the world's largest solar facilities.

PG&E also continues to be a leader in supporting policy action on climate change. Last year, building on our support for California's landmark Global Warming Solutions Act, we stepped up our engagement with federal policy makers in support of national legislation mandating greenhouse gas cuts and creating market mechanisms to begin driving wiser long-term energy choices.

CONNECTED

Serving 15 million Californians, PG&E is plugged into hundreds of economically and culturally vibrant communities throughout the state. We are intertwined with life there in a multitude of ways. As the provider of a service that is absolutely essential to everyday living and economic vitality. As a provider of quality jobs. As a solid partner for diverse small and mid-sized businesses that are the lifeblood of local economies. As a giver of volunteer time and charitable dollars to support causes that reflect the values we share as neighbors and fellow Californians. In return, our communities give back to us—by giving us the great privilege to serve them and by being great places for our employees to live and work.



CONNECTED Strong connections with our communities are a natural extension of the strong relationships we are building with our customers. As a company that operates with the public trust, we know that strengthening those ties is important to our long-term success.

PG&E Corporation has committed to provide at least $60 million in shareholder-funded charitable contributions from 2005 to 2009. In addition to the company's giving, PG&E employees and retirees also give generously through our annual Campaign for the Community. This year they committed $3.9 million to a wide array of recipients.

Through innovative partnerships in our communities, PG&E is recruiting and training the next generation of California utility workers, with a focus on building a workforce that reflects the rich diversity of the customers we serve.

In 2008, we will focus PG&E's charitable giving on environmental and energy sustainability programs. These initiatives will include environmental education programs such as PG&E's award-winning Solar Schools initiative, community solar energy projects, habitat restoration and conservation work, and efforts to reduce greenhouse gas emissions.

Underpinning our partnerships with our customers and communities is a commitment to build a workforce at PG&E that reflects the rich diversity of the markets we serve. We need to hire 1,000 qualified new line workers in the next three years as many of our existing employees become eligible to retire. Some companies in similar situations would look out of state; we are looking directly to our communities and working with them to create the pool of candidates that will carry PG&E into the next few decades. Recently, we created the PowerPathway™ program, an innovative partnership that is engaging California community colleges, government, labor, foundations, and other community-based organizations to work hand in hand with PG&E to prepare individuals for high-paying, high-demand energy sector positions specific to PG&E's hiring needs.

Habitat for Humanity fit solar panels on new homes it built in PG&E's service area last year, thanks to a first-of-its-kind effort created with the support of PG&E's charitable program and our renewable energy expertise.

Our company helps to boost community economies through the purchase of goods and services from diverse local businesses. Through our Supplier Diversity Program, we provide women-, minority-, and service-disabled-veteran-owned businesses with opportunities to supply products and services to PG&E. In 2007, we helped support these businesses with $599 million of diversity spending, representing 21.7 percent of overall purchases. We also work with community organizations to increase training, certification, and contracting opportunities for diverse suppliers.

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)	2007	2006
Operating Revenues	$ 13,237	$ 12,539
Net Income		
Earnings from operations(1)	1,006	922
Items impacting comparability(2)	–	69
Reported consolidated net income	1,006	991
Income Per Common Share, diluted		
Earnings from operations(1)	2.78	2.57
Items impacting comparability(2)	–	0.19
Reported consolidated net earnings per common share, diluted	2.78	2.76
Dividends Declared Per Common Share	1.44	1.32
Total Assets at December 31,	36,648	34,803
Number of common shareholders at December 31,	89,166	93,170
Number of common shares outstanding at December 31,(3)	379,646,276	374,181,059

(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. For 2007, PG&E Corporation did not have any items impacting comparability to report.

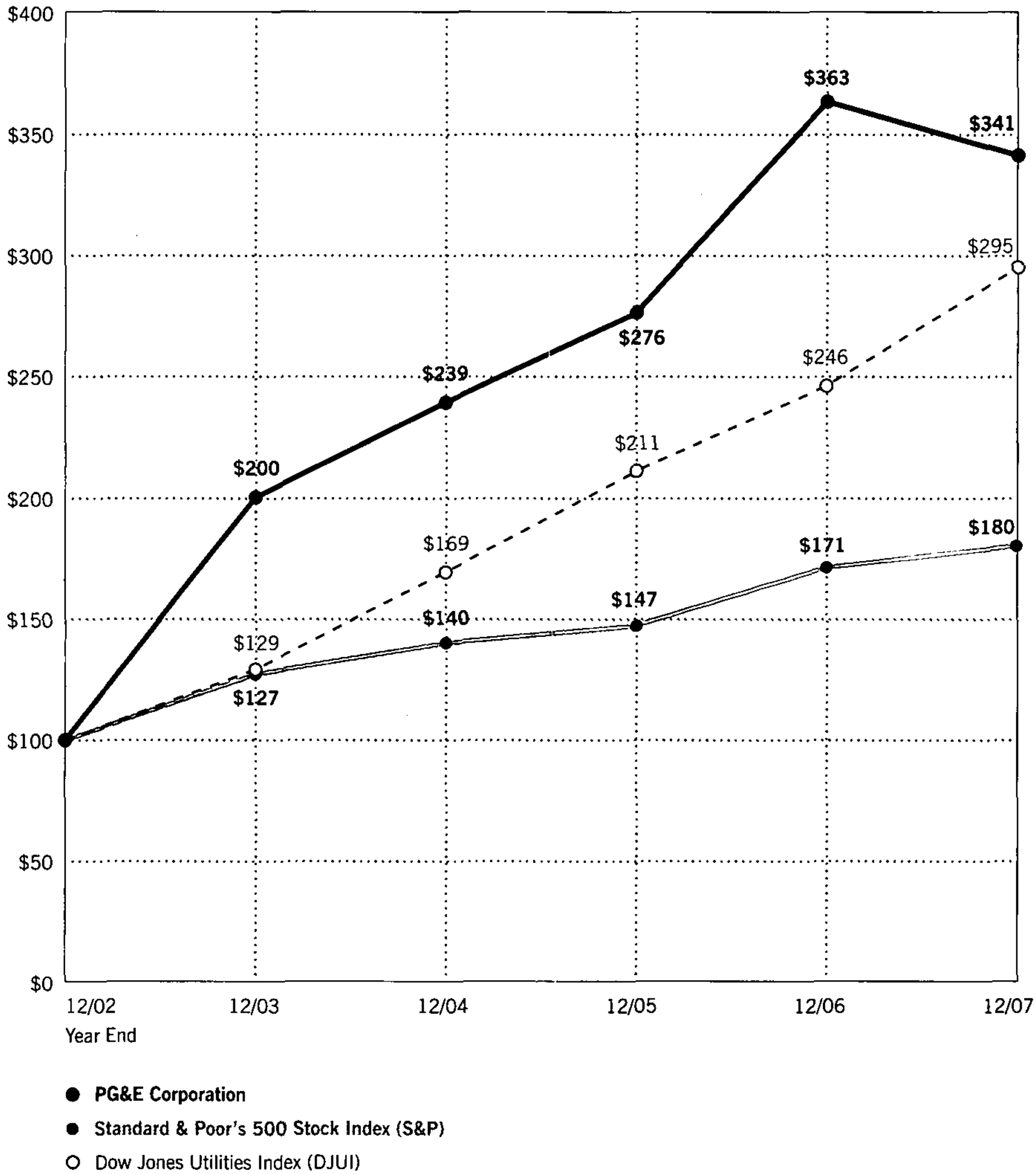
Items impacting comparability for 2006 include:

- The recovery of approximately $77 million ($0.21 per common share), after-tax, of Scheduling Coordinator costs, incurred from April 1998 through September 2006, based on a Federal Energy Regulatory Commission 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 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 common share), after-tax, to reflect consolidation of various positions in connection with the Utility's effort to streamline processes and achieve cost and operating efficiencies through implementation of various initiatives.

(3) The common shares outstanding include 24,665,500 shares at December 31, 2007 and December 31, 2006, 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, 2002, 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)	2007	2006	2005	2004[1]	2003
PG&E Corporation[2]					
For the Year					
Operating revenues	$13,237	$12,539	$11,703	$11,080	$10,435
Operating income	2,114	2,108	1,970	7,118	2,343
Income from continuing operations	1,006	991	904	3,820	791
Earnings per common share from continuing operations, basic	2.79	2.78	2.37	9.16	1.96
Earnings per common share from continuing operations, diluted	2.78	2.76	2.34	8.97	1.92
Dividends declared per common share[3]	1.44	1.32	1.23	–	–
At Year-End					
Book value per common share[4]	$ 22.91	$ 21.24	$ 19.94	$ 20.90	$ 10.16
Common stock price per share	43.09	47.33	37.12	33.28	27.77
Total assets	36,648	34,803	34,074	34,540	30,175
Long-term debt (excluding current portion)	8,171	6,697	6,976	7,323	3,314
Rate reduction bonds (excluding current portion)	–	–	290	580	870
Energy recovery bonds (excluding current portion)	1,582	1,936	2,276	–	–
Financial debt subject to compromise	–	–	–	–	5,603
Preferred stock of subsidiary with mandatory redemption provisions	–	–	–	122	137
Pacific Gas and Electric Company					
For the Year					
Operating revenues	$13,238	$12,539	$11,704	$11,080	$10,438
Operating income	2,125	2,115	1,970	7,144	2,339
Income available for common stock	1,010	971	918	3,961	901
At Year-End					
Total assets	$36,326	$34,371	$33,783	$34,302	$29,066
Long-term debt (excluding current portion)	7,891	6,697	6,696	7,043	2,431
Rate reduction bonds (excluding current portion)	–	–	290	580	870
Energy recovery bonds (excluding current portion)	1,582	1,936	2,276	–	–
Financial debt subject to compromise	–	–	–	–	5,603
Preferred stock with mandatory redemption provisions	–	–	–	122	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. Pacific Gas and Electric Company's reorganization under Chapter 11 became effective on April 12, 2004.

(2) Matters relating to discontinued operations are discussed in the section entitled "Management's Discussion and Analysis of Financial Condition and Results of Operations" and in Note 7 of the Notes to the Consolidated Financial Statements.

(3) The Board of Directors of PG&E Corporation declared a cash dividend of $0.30 per quarter for the first three quarters of 2005. In the fourth quarter of 2005, the Board of Directors increased the quarterly cash dividend to $0.33 per share. Beginning in the first quarter of 2007, the Board of Directors increased the quarterly cash dividend to $0.36 per share. See Note 8 of the Notes to the Consolidated Financial Statements.

(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 Note 10 of the Notes to the Consolidated Financial Statements.

OVERVIEW

PG&E Corporation, incorporated in California in 1995, 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 ("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. 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 4.3 million natural gas distribution customers at December 31, 2007. The Utility had approximately $36.3 billion in assets at December 31, 2007 and generated revenues of approximately $13.2 billion in the 12 months ended December 31, 2007.

The Utility is regulated primarily by the California Public Utilities Commission ("CPUC") and the Federal Energy Regulatory Commission ("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 ("rate base"). Changes in any individual revenue requirement affect customers' rates and could affect the Utility's revenues.

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, which the Utility is required to consolidate under applicable accounting standards and variable interest entities for which the Utility is subject to a majority of the risk of loss or gain. This combined Management's Discussion and Analysis of Financial Condition and Results of Operations of PG&E Corporation and the Utility should be read in conjunction with the Consolidated Financial Statements and the Notes to the Consolidated Financial Statements included in this annual report.

SUMMARY OF CHANGES IN EARNINGS PER COMMON SHARE AND NET INCOME FOR 2007

PG&E Corporation's diluted earnings per common share ("EPS") for 2007 was $2.78 per share, compared to $2.76 per share for 2006. For 2007, PG&E Corporation's net income increased by approximately $15 million, or 2%, to $1,006 million, compared to $991 million in 2006. The increase in diluted EPS and net income for 2007 compared to 2006 is primarily due to positive regulatory outcomes, in combination with certain events that affected 2006 net income but did not recur in 2007.

Net income and EPS in 2007 reflect increased revenues of $125 million associated with the Utility's return on equity ("ROE") on additional capital investments authorized by the CPUC in the Utility's General Rate Case ("GRC") effective January 1, 2007, and by the FERC in the Utility's transmission owner ("TO") rate case effective March 1, 2007. In addition, net income and EPS in 2007 were favorably affected on a comparative basis by approximately $18 million, the amount of an environmental remediation charge taken in 2006 as a result of changes in the California Regional Water Control Board's imposed remediation levels. These increases were principally offset by amounts resulting from the following events that increased 2006 net income but did not recur in 2007: (1) the FERC's approval of recovery of scheduling coordinator ("SC") costs that the Utility began incurring in 1998 (representing a $77 million decrease in net income as compared to 2006), (2) the recovery of certain interest and litigation costs following the CPUC's completion of a verification audit (representing a $39 million decrease in net income as compared to 2006), and (3) a decrease in the amount accrued for long-term disability benefits and a tax benefit recognized in 2006 related to a tax loss carry forward (representing a $26 million decrease in net income as compared to 2006).

KEY FACTORS AFFECTING RESULTS OF OPERATIONS AND FINANCIAL CONDITION

PG&E Corporation 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, timely recover its authorized costs, and earn its authorized rate of return. A number of 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 that the Utility is authorized to recover from customers are primarily determined through regulatory proceedings. The timing of CPUC and FERC decisions also affect when the Utility is able to record the authorized revenues. In March 2007, the CPUC issued a decision in the 2007 GRC, effective January 1, 2007, establishing a $4.9 billion annual revenue requirement for the Utility's electric and natural gas distribution operations and its electric generation operations for 2007 through 2010, with authorized increases in each of 2008, 2009, and 2010. In June 2007, the FERC approved the Utility's annual electric transmission retail revenue requirement at $674 million, effective March 1, 2007. In addition, in September 2007, the FERC accepted the Utility's proposed electric transmission retail revenue requirement effective March 1, 2008, subject to hearing and refund, an amount that would represent a revenue increase of approximately $78 million over March 1, 2007 rates. In September 2007, the CPUC approved a multi-party settlement agreement (known as the Gas Accord IV) that establishes the Utility's natural gas transmission and storage rates and associated revenue requirements for 2008 through 2010, with 2008 rates set at $446 million with slight escalations in each subsequent year. Finally, during 2007, the CPUC established incentive ratemaking mechanisms applicable to the California investor-owned utilities' implementation of their energy efficiency programs funded for the 2006–2008 and 2009–2011 program cycles. The maximum amount of incentives that the Utility could earn (and the maximum amount that the Utility could be required to reimburse customers) over the 2006–2008 program cycle is $180 million. The actual amount and timing of the financial impact will depend on the level of energy efficiency savings actually achieved over the three-year program cycle, the amount of the savings attributable to the Utility's energy efficiency programs, and when the applicable accounting standard for recognizing incentives or reimbursement obligations is met. The outcome of various other pending regulatory proceedings also could have a material effect on the Utility's results of operations. (See "Regulatory Matters" below.)
- **Capital Structure and Return on Common Equity** — In 2007, the CPUC authorized the Utility to earn a ROE of 11.35% on its electric and natural gas distribution and electric generation rate base and to maintain an authorized capital structure that included a 52% common equity component. On December 20, 2007, the CPUC authorized the Utility to earn the same ROE and maintain the same capital structure in 2008. In December 2007, Moody's Investors Service ("Moody's") upgraded the Utility's credit rating to A3, thereby terminating a provision in the December 2003 settlement agreement among PG&E Corporation, the Utility, and the CPUC to resolve the Utility's proceeding under Chapter 11 of the U.S. Bankruptcy Code ("Chapter 11 Settlement Agreement") that had required the CPUC to authorize a minimum ROE for the Utility of 11.22% and a minimum common equity component of 52% until the Utility received a credit rating of "A3" from Moody's or "A-" from Standard & Poor's Ratings Service ("S&P"). (See "Liquidity and Financial Resources" below.)

- **The Ability of the Utility to Control Costs and Achieve Operational Efficiencies and Improved Reliability** — The forecasted operating costs and capital expenditures used to set the revenue requirements authorized in the GRC reflected assumptions about future cost savings that were expected to be achieved through implementation of various initiatives intended to increase cost efficiencies, achieve operational excellence, and improve customer service. The cost of many of these initiatives is substantial, with savings expected to be realized in later years. If the actual cost savings exceed the contemplated savings, such benefits would accrue to shareholders. Conversely, to the extent that contemplated cost savings are not realized, earnings available for shareholders would be reduced. One major initiative involving new work processes, information systems, and technology has resulted in significant delays and increased costs to respond to customer requests for new service, although the Utility is attempting to remedy the problems. The Utility also is undertaking a thorough review of its operating practices and procedures and, depending on the results of this review, may increase spending to address any identified issues associated with the reliability and safety of the electric and natural gas distribution systems. (See "Results of Operations – Operating and Maintenance" and "Risk Factors" below.) In addition to capital expenditures authorized to be recovered through GRC-authorized rates and FERC-authorized TO rates, the CPUC has authorized the Utility to make substantial capital expenditures to install an advanced metering infrastructure, to invest in new generation resources, and to improve existing generation facilities, as described below under "Capital Expenditures." The Utility will incur depreciation, property tax, and interest expense associated with these capital expenditures. The Utility's financial condition and results of operations will be impacted by its ability to manage its operating costs and capital expenditures within authorized revenues.

- **The Amount and Timing of Debt and Equity Financing Needs** — During 2007, the Utility issued $1.2 billion of long-term debt to finance capital expenditures and for working capital. (See Note 4 of the Notes to the Consolidated Financial Statements.) The Utility's needs for additional financing in 2008 and future years will be affected by the amount and timing of capital expenditures as well as by the amount and timing of interest payments related to the remaining disputed claims made by electricity suppliers in the Utility's proceeding under Chapter 11 of the U.S. Bankruptcy Code ("Disputed Claims"). (See Note 15 of the Notes to the Consolidated Financial Statements.) PG&E Corporation's and the Utility's financial condition and results of operations will be affected by the interest rates, timing, and terms and conditions of any such financing. PG&E Corporation plans to contribute equity to the Utility to maintain the Utility's authorized capital structure. The timing and amount of these equity contributions will affect the timing and amount of any new PG&E Corporation equity issuances and/or debt issuances which, in turn, will affect PG&E Corporation's results of operations and financial condition. (See "Liquidity and Financial Resources" below.)

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 "Risk Factors" below.

FORWARD-LOOKING STATEMENTS

This combined annual report and the letter to shareholders that accompanies it contain 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, anticipated costs and savings associated with the Utility's efforts to implement changes to its business processes and systems, estimated capital expenditures, estimated Utility rate base, estimated environmental remediation liabilities, estimated tax 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 manage capital expenditures and operating costs within authorized levels and recover costs through rates in a timely manner;
- the outcome of regulatory proceedings, including pending and future ratemaking proceedings 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 businesses;
- 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 ("Diablo Canyon"), the occurrence of unplanned outages at Diablo Canyon, or the temporary or permanent cessation of operations at Diablo Canyon;
- whether the Utility can maintain the cost efficiencies it has recognized from its completed initiatives to improve its business processes and customer service, improve its performance following the October 2007 implementation of new work processes and systems, and identify and successfully implement additional cost-saving measures;
- whether the Utility incurs substantial unanticipated expense to improve the safety and reliability of its electric and natural gas distribution systems;
- whether the Utility achieves the CPUC's energy efficiency targets and recognizes any incentives the Utility may earn in a timely manner;
- 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 new rules of the California Independent System Operator ("CAISO") 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 and liabilities in connection with litigation that are not recoverable through rates, from insurance, or from other third parties;
- the ability of PG&E Corporation and/or the Utility to access capital markets and other sources of credit in a timely manner on favorable terms;
- the impact of environmental laws and regulations and the costs of compliance and remediation;
- the effect of municipalization, direct access, community choice aggregation, or other forms of bypass; and
- the impact of changes in federal or state tax laws, policies, or regulations.

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 2007, 2006, and 2005:

	Year ended December 31,		
(in millions)	2007	2006	2005
Utility			
Electric operating revenues	$ 9,481	$ 8,752	$ 7,927
Natural gas operating revenues	3,757	3,787	3,777
Total operating revenues	13,238	12,539	11,704
Cost of electricity	3,437	2,922	2,410
Cost of natural gas	2,035	2,097	2,191
Operating and maintenance	3,872	3,697	3,399
Depreciation, amortization, and decommissioning	1,769	1,708	1,734
Total operating expenses	11,113	10,424	9,734
Operating income	2,125	2,115	1,970
Interest income	150	175	76
Interest expense	(732)	(710)	(554)
Other income (expense), net[1]	38	(7)	–
Income before income taxes	1,581	1,573	1,492
Income tax provision	571	602	574
Income available for common stock	$ 1,010	$ 971	$ 918
PG&E Corporation, Eliminations, and Other[2]			
Operating revenues	$ (1)	$ –	$ (1)
Operating (gain) expenses	10	7	(1)
Operating loss	(11)	(7)	–
Interest income	14	13	4
Interest expense	(30)	(28)	(29)
Other expense, net	(9)	(6)	(19)
Loss before income taxes	(36)	(28)	(44)
Income tax benefit	(32)	(48)	(30)
Income (loss) from continuing operations	(4)	20	(14)
Discontinued operations[3]	–	–	13
Net income (loss)	$ (4)	$ 20	$ (1)
Consolidated Total			
Operating revenues	$13,237	$12,539	$11,703
Operating expenses	11,123	10,431	9,733
Operating income	2,114	2,108	1,970
Interest income	164	188	80
Interest expense	(762)	(738)	(583)
Other income (expense), net[1]	29	(13)	(19)
Income before income taxes	1,545	1,545	1,448
Income tax provision	539	554	544
Income from continuing operations	1,006	991	904
Discontinued operations[3]	–	–	13
Net income	$ 1,006	$ 991	$ 917

(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, National Energy & Gas Transmission, Inc ("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 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 reasonable operating and capital costs and earn a fair return. Revenue requirements are primarily determined based on the Utility's forecast of future costs. The CPUC also has established ratemaking mechanisms to permit the Utility to timely recover its costs to procure electricity and natural gas supplied to its customers. (See "Risk Management Activities" below.)

The GRC is the primary proceeding in which the CPUC determines the amount of revenue requirements that the Utility can recover for basic business and operational costs related to its electricity and natural gas distribution and electricity generation operations. The CPUC sets revenue requirements for a rate case 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. Effective January 1, 2007, the CPUC authorized the Utility to collect revenue requirements of approximately $2.9 billion for electricity distribution, approximately $1.0 billion for natural gas distribution, and approximately $1.0 billion for electricity generation operations. The CPUC also authorized attrition adjustments to authorized revenues of $125 million in 2008 and 2009, and $90 million in 2010. In addition, the decision authorizes a one-time additional adjustment of $35 million in 2009 for the cost of a second refueling outage at the Utility's Diablo Canyon nuclear power plant.

Historically, the CPUC also has conducted 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. For 2006, 2007, and 2008, the CPUC has authorized an 11.35% ROE for the Utility and a capital structure that includes a 52% common equity component. The CPUC is expected to issue a decision in April 2008 addressing proposals to replace the annual cost of capital proceeding with an annual cost of capital adjustment mechanism for 2009 through 2013. (See "Regulatory Matters – 2008 Cost of Capital Proceeding" below.)

The FERC sets the Utility's rates for electric transmission services. The primary FERC ratemaking proceeding to determine the amount of revenue requirements that the Utility can recover for its electric transmission costs and ROE is the TO rate case. A TO rate case generally 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. In June 2007, the FERC approved a settlement that sets the Utility's annual transmission retail revenue requirement at $674 million effective March 1, 2007.

The Utility's gas transmission and storage service, rates, and market structure are set by the CPUC. In September 2007, the CPUC issued a final decision approving a multiparty settlement agreement, known as the Gas Accord IV, to establish the Utility's natural gas transmission and storage rates and associated revenue requirements for 2008 through 2010. The Gas Accord IV establishes a 2008 natural gas transmission and storage revenue requirement of $446 million, with slight increases in 2009 and 2010.

The Utility's revenues for natural gas transmission services may fluctuate 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. The Utility's actual revenues for natural gas transmission service are based on actual volumes sold; accordingly, natural gas transmission service revenues are subject to volumetric risk. (See the "Natural Gas Transportation and Storage" section in "Risk Management Activities" below.)

The Utility is also authorized to collect revenue requirements from customers to fund public purpose, demand response, and energy efficiency programs, including the California Solar Initiative program and the Self-Generation Incentive program. In addition, the Utility is authorized to collect revenue requirements to recover its capital costs for projects such as new Utility-owned generation resource facilities and the installation of advanced meters for its electric and gas customers.

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 results of operations. 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, these 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 following presents the Utility's operating results for 2007, 2006, and 2005.

Electric Operating Revenues

The Utility provides electricity to residential, industrial, and small and large commercial customers through its own generation facilities and through contracts with third parties under power purchase agreements. In addition, the Utility relies on electricity provided under long-term contracts entered into by the California Department of Water Resources ("DWR") to meet a material portion of the Utility's customers' demand ("load"). The Utility's electric operating revenues consist of amounts charged to customers for electricity generation and procurement and for electric transmission and distribution services.

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

(in millions)	2007	2006	2005
Electric operating revenues	$11,710	$10,871	$ 9,626
DWR pass-through revenues[1]	(2,229)	(2,119)	(1,699)
Total electric operating revenues	$ 9,481	$ 8,752	$ 7,927
Total electricity sales (in Gigawatt hours)	64,986	64,725	61,150

(1) These are revenues collected on behalf of the DWR for electricity allocated to the Utility's customers under contracts between the DWR and power suppliers, and are not included in the Utility's Consolidated Statements of Income.

The Utility's electric operating revenues increased by approximately $729 million, or approximately 8%, in 2007 compared to 2006 mainly due to the following factors:

- Electricity procurement costs, which are passed through to customers, increased by approximately $742 million. (See "Cost of Electricity" below.)
- The 2007 GRC increased 2007 base revenue requirements by approximately $231 million.
- Revenues from public purpose programs, including the California Solar Initiative program, increased by approximately $141 million. (See Note 3 of the Notes to Consolidated Financial Statements.)
- Electric transmission revenues increased by approximately $74 million, including an increase in revenues as authorized in the TO rate case.

These increases were partially offset by the following:

- Transmission revenues decreased by approximately $200 million primarily due to a decrease in the number of reliability must run ("RMR") agreements the Utility has with the CAISO and the associated costs. 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 responsibilities to meet these requirements, the number of RMR agreements with the CAISO and the associated costs, and the related revenues, will decline. (See "Cost of Electricity" below.)
- Revenues in 2006 included approximately $136 million for recovery of SC costs the Utility incurred from April 1998 through December 2005, as ordered by the FERC. No similar amount was recognized in 2007.
- Revenues in 2006 included approximately $65 million for recovery of net interest related to Disputed Claims for the period between the effective date of the Utility's plan of reorganization under Chapter 11 in April 2004 and the first issuance of the Energy Recovery Bonds ("ERBs") in February 2005, and for certain energy supplier refund litigation costs upon completion of the CPUC's 2005 Annual Electric True-up verification audit. No similar amount was recognized in 2007.
- Other electric operating revenues, including the recovery of a pension revenue requirement as authorized by the CPUC, decreased by approximately $58 million.

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 dedicated rate component ("DRC") charges related to the ERBs increased by approximately $175 million. (See 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.

- As discussed above, in 2006, the Utility recognized approximately $136 million following the FERC's order allowing the Utility to recover SC costs that the Utility incurred from April 1998 through December 2005. No similar amount was recognized in 2005.

- 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, but no similar amount was recognized in 2005.

- Transmission revenues increased by approximately $90 million primarily due to an increase in revenues, as authorized by the FERC.

- As discussed above, the Utility recognized approximately $65 million due to the recovery of net interest costs related to Disputed Claims for the period between the effective date of the Utility's plan of reorganization under Chapter 11 and the date the first series of ERBs was issued, and for certain energy supplier refund litigation costs, but no similar amount was recognized in 2005.

- The Utility recovered approximately $59 million of net interest costs related to Disputed Claims incurred after the issuance of the first series of ERBs, as authorized by the CPUC, but no similar amount was recognized in 2005.

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, but no similar amount was recognized 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, but no similar amounts were recorded in 2006 after the refinancing of the settlement regulatory asset through the issuance of the ERBs.

- 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 as well as the after-tax proceeds of energy supplier refunds used to reduce the size of the second series of ERBs.

The Utility's electric operating revenues for the period 2008 through 2010 are expected to increase, as authorized by the CPUC in the 2007 GRC and by the FERC in future TO rate cases. In addition, the Utility expects to continue to collect revenue requirements related to CPUC-approved capital expenditures, including the new Utility-owned generation projects and the SmartMeter™ project. (See "Capital Expenditures" below.) Revenue requirements associated with new or expanded public purpose programs, such as the California Solar Initiative, will result in increased electric operating revenues. In addition, the Utility may recognize incentive revenues to the extent it achieves the CPUC's energy efficiency goals. Finally, future electric operating revenues will be impacted by changes in the cost of electricity.

Cost of Electricity

The Utility's cost of electricity includes electricity purchase costs, hedging costs, and the cost of fuel used by its generation facilities or supplied to other facilities under tolling agreements. It excludes costs associated with the Utility's own generation facilities, which are included in Operating and Maintenance expense in the Consolidated Statements of Income. The Utility's cost of purchased power and the cost of fuel used in Utility-owned generation are passed through to customers.

The Utility is required to dispatch, or schedule, all of the electricity resources within its portfolio 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 therefore to sell this excess 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. The Utility's net proceeds from the sale of surplus electricity 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:

(in millions)	2007	2006	2005
Cost of purchased power[1]	$ 3,443	$ 3,114	$ 2,706
Proceeds from surplus sales allocated to the Utility	(155)	(343)	(478)
Fuel used in own generation	149	151	182
Total cost of electricity	$ 3,437	$ 2,922	$ 2,410
Average cost of purchased power per kWh	$ 0.089	$ 0.084	$ 0.079
Total purchased power (in millions of kWh)	38,828	36,913	34,203

(1) Includes costs associated with RMR agreements.

The Utility's total cost of electricity increased by approximately $515 million, or 18%, in 2007 compared to 2006. This increase was primarily driven by a 6% increase in the average cost of purchased power. The average cost of purchased power increased $0.005 per kilowatt-hour ("kWh") from 2006 to 2007 primarily due to higher energy payments made to qualifying facilities ("QFs") after their five-year fixed price contracts expired during the summer of 2006. In addition, the Utility increased the volume of its third-party power purchases primarily due to a reduction in the availability of lower-cost hydroelectric power resulting from less than average precipitation during 2007 as compared to 2006. These increases were partially offset by a decrease in costs associated with RMR agreements.

The Utility's cost of electricity increased by approximately $512 million, or 21%, in 2006 compared to 2005, mainly due to an increase in total purchased power of 2,710 million kWh, or 8%, and an increase in the average cost of purchased power of $0.005 per kWh, or 6%, in 2006, compared to 2005. This was primarily caused by an increase in volume of purchased power due to greater customer demand during unseasonably warm weather during the summer of 2006 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 (i.e., generation, transmission, and distribution) grew, further increasing volume.

The Utility's cost of electricity in 2008 and future years will depend upon electricity and natural gas prices, the level of hydroelectric and nuclear power that the Utility produces, the cost of procuring more renewable energy, impacts from termination of DWR contracts, CPUC-ordered changes to QF pricing, and changes in customer demand. (See the "Risk Management Activities – Price Risk" below.)

The Utility's future cost of electricity also may be affected by federal or state legislation or rules which may be adopted to regulate the emissions of greenhouse gases from the Utility's electricity generating facilities or the generating facilities from which the Utility procures electricity. As directed by recent California legislation, the CPUC has already adopted an interim greenhouse gas emissions performance standard that would apply to electricity procured or generated by the Utility. (See "Risk Factors" below.)

Natural Gas Operating Revenues

The Utility sells natural gas and natural gas transportation services. The Utility's transportation services are provided by a transmission system and a distribution system. The transmission system transports gas throughout California for delivery to the Utility's distribution system which, in turn, delivers natural gas to end-use customers. The transmission system also delivers natural gas to large end-use customers who are connected directly to the transmission system. In addition, the Utility 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 customers. The non-core customer class is comprised of industrial and larger commercial customers. The Utility provides natural gas transportation 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 either the Utility or alternate energy service providers. The Utility does not procure natural gas for non-core customers. When the Utility provides both transportation and natural gas supply, the Utility refers to the combined service as bundled natural gas service. In 2007, core customers represented over 99% of the Utility's total customers and approximately 38% of its total natural gas deliveries, while non-core customers comprised less than 1% of the Utility's total customers and approximately 62% of its total natural gas deliveries. As discussed above, because the Utility sells most of its transportation services under volumetric rates, the Utility is exposed to volumetric revenue risk.

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

(in millions)	2007	2006	2005
Bundled natural gas revenues	$3,417	$3,472	$3,539
Transportation service-only revenues	340	315	238
Total natural gas operating revenues	$3,757	$3,787	$3,777
Average bundled revenue per Mcf of natural gas sold	$12.93	$12.89	$13.05
Total bundled natural gas sales (in millions of Mcf)	264	269	271

The Utility's natural gas operating revenues decreased by approximately $30 million, or less than one percent, in 2007 compared to 2006. This was primarily due to a decrease in bundled natural gas revenues of approximately $55 million, or 2%, as a result of decreases in the cost of natural gas, which are passed through to customers. This decrease was partially offset by the increased base revenue requirements authorized in the 2007 GRC and an increase in revenue requirements relating to the SmartMeter™ project.

The Utility's natural gas operating revenues increased by approximately $10 million, or less than one percent, in 2006 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, but no similar amount was recorded in 2005.
- 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%, as a result of an increase in volume and a slight increase in rates as authorized by the CPUC.

These increases were partially offset by the following:

- The cost of natural gas, which is passed through to customers, decreased by approximately $132 million.
- 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, but no similar amount was recorded in 2006.

Future natural gas operating revenues will be impacted by changes in the cost of natural gas, the Utility's gas transportation rates, natural gas throughput volume, and other factors. For 2008 through 2010, the Gas Accord IV settlement agreement provides for an overall modest increase in the revenue requirements and rates for the Utility's gas transmission and storage services. In addition, the Utility's natural gas operating revenues for distribution are expected to increase through 2010 as a result of revenue requirement increases authorized by the CPUC in the 2007 GRC. Finally, the Utility may recognize incentive revenues to the extent it achieves the CPUC's energy efficiency goals.

Cost of Natural Gas

The Utility's cost of natural gas includes the purchase costs of natural gas and transportation costs on interstate pipelines and intrastate pipelines, but excludes the transportation costs for non-core customers, which are included in Operating and Maintenance expense in the Consolidated Statements of Income.

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

(in millions)	2007	2006	2005
Cost of natural gas sold	$1,859	$1,958	$2,051
Cost of natural gas transportation	176	139	140
Total cost of natural gas	$2,035	$2,097	$2,191
Average cost per Mcf of natural gas sold	$ 7.04	$ 7.28	$ 7.57
Total natural gas sold (in millions of Mcf)	264	269	271

The Utility's total cost of natural gas decreased by approximately $62 million, or 3%, in 2007 compared to 2006, primarily due to a decrease in the average market price of natural gas purchased of approximately $0.24 per thousand cubic feet ("Mcf"), or 3%. Average market prices were significantly higher in the beginning of 2006 as damages to production facilities caused by severe weather reduced natural gas supply. In addition, the price of natural gas has declined due to a relatively mild hurricane season in 2007 as compared to industry forecasts, resulting in no material supply disruptions, and a relatively large amount of natural gas in storage across the nation.

The Utility's total cost of natural gas decreased by approximately $94 million, or 4%, in 2006 compared to 2005, primarily due to a decrease in the average market price of natural gas purchased of approximately $0.29 per Mcf, or 4%. This decrease was primarily due to significantly higher than average market prices throughout 2005 as a result of severe weather conditions and a strong hurricane season as compared to the same period in 2006.

The Utility's cost of natural gas in subsequent periods will be primarily determined by market forces in North America. Market forces include supply availability, customer demand, and industry perceptions of risks that may affect either, such as the possibility of hurricanes in the gas-producing regions of the Gulf of Mexico or of protracted heat waves that may increase gas-fired electric demand from high air conditioning loads.

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 revenues authorized by the CPUC and the FERC in various proceedings.

The Utility's operating and maintenance expenses increased by approximately $175 million, or 5%, in 2007 compared to 2006, mainly due to the following factors:

- Payments for customer assistance and public purpose programs, such as the California Solar Initiative program and the Mass Market program, increased by approximately $99 million primarily due to increased customer participation in these programs.
- The Utility's distribution expenses increased by approximately $40 million primarily due to service costs related to the creation of new dispatch and scheduling stations and vegetation management in the Utility's service territory.
- Billing and collection costs increased by approximately $33 million.
- Labor costs increased by approximately $33 million primarily due to higher employee headcount and increased base salaries and incentives.
- Costs of outside consulting services and contracts primarily related to information systems increased by approximately $22 million.
- Approximately $22 million was accrued for missed meal payments to certain Utility employees covered under collective bargaining agreements. (See Note 17 "California Labor Code Issues" of the Notes to the Consolidated Financial Statements.)
- Workers' compensation expense increased by approximately $20 million due to a decrease to the discount rate on the workers' compensation obligation and higher than expected workers' compensation claims.
- Property taxes increased by approximately $12 million due to electric plant growth, tax rate increases, and increases in assessed values in 2007.
- In 2006, the Utility reduced its accrual for long-term disability benefits by approximately $11 million reflecting changes in sick leave eligibility rules, but there was no similar adjustment in 2007.

The above increases were offset by the following factors:

- Pension expense decreased by approximately $57 million consistent with the annual pension contribution, as approved by the CPUC in June 2006.
- Severance costs in 2007 were approximately $30 million lower than in 2006.
- In 2006, the Utility increased its environmental remediation accrual by approximately $30 million due to changes in the California Regional Water Quality Control Board's imposed remediation levels, but there was no similar adjustment in 2007.

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 expense increased approximately $176 million as a result of a CPUC-approved settlement to recover pension contributions.
- Expenses for customer assistance and public purpose programs increased approximately $125 million.
- Compensation expense increased approximately $54 million reflecting increased base salaries and incentives.
- Costs, including outside consulting fees, related to the Utility's continued efforts to achieve operating efficiencies increased approximately $50 million.
- The Utility accrued approximately $35 million for severance costs in connection with the Utility's continued efforts to eliminate and consolidate various employee positions in numerous Utility locations. (See Note 17 of the Notes to the Consolidated Financial Statements.)
- 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, tax rate increases, and increases in assessed values in 2006.

The above increases were 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.

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, material costs, and various other administrative and general expenses. The Utility anticipates that it will incur higher material, permitting, and labor costs (including potential wage increase of newly union organized classifications resulting from collective bargaining) in the future as well as higher costs to operate and maintain its aging infrastructure. The Utility also expects that employee severance costs will increase as the Utility continues its efforts to achieve cost and operating efficiencies. The Utility anticipates that it will make additional payments to employees for missed or delayed meals to comply with California labor law as the Utility's investigation into this matter continues. (See Note 17 of the Notes to the Consolidated Financial Statements for a discussion of severance costs and California labor code issues.) In addition, the Utility may incur costs, not included in forecasts used to set rates in the GRC, to address safety and reliability issues in the Utility's electric and natural gas distribution system depending on the outcome of its review of its operating practices and procedures following recent electric transformer failures and the discovery that some natural gas maintenance records did not accurately reflect field conditions. (See "Risk Factors" below.) The Utility also expects that it will incur higher expenses in subsequent periods to comply with the requirements of renewed hydroelectric generation licenses and to complete the construction of the dry cask storage facility at Diablo Canyon. The Utility's operating and maintenance expenses will also increase in the first quarter of 2008 due to the planned refueling outage at Diablo Canyon Unit 2. The Utility anticipates that the refueling outage will last approximately 76 days, which is longer than the average outage duration, in order for the Utility to replace the steam generators in Unit 2.

Depreciation, Amortization, and Decommissioning

The Utility's depreciation, amortization, and decommissioning expenses increased by approximately $61 million, or 4%, in 2007 compared to 2006, mainly due to an approximately $121 million increase in depreciation expense as a result of depreciation rate changes and plant additions in 2007 authorized by the 2007 GRC decision. This was partially offset by:

- The Utility recorded lower decommissioning expense of approximately $53 million as a result of the 2007 GRC decision to refund over-collections of decommissioning expense to customers.
- Other depreciation, amortization, and decommissioning expenses, including amortization of the ERB regulatory asset, decreased by $7 million.

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

- The Utility recorded approximately $141 million in 2005 for amortization of the settlement regulatory asset. The settlement regulatory asset was refinanced with the issuance of the first series of ERBs on February 10, 2005. The Utility recorded approximately $137 million in 2006 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. The Utility did not have a similar expense related to the settlement regulatory asset 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 Reduction Bonds ("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:

- Depreciation expense increased by approximately $35 million as a result of plant additions in 2006.

The Utility's depreciation, amortization, and decommissioning expenses in subsequent years are expected to increase as a result of an overall increase in capital expenditures and implementation of depreciation rates authorized by the 2007 GRC decision.

Interest Income

The Utility's interest income decreased by approximately $25 million, or 14%, in 2007 compared to 2006. In 2006, the FERC approved the Utility's recovery of SC costs it had previously incurred, including interest of approximately $47 million. No similar amount was recognized in 2007. This decrease was partially offset by the receipt of approximately $16 million in 2007 related to the settlement of Internal Revenue Service refund claims. In addition, other interest income, including interest income associated with certain balancing accounts, increased by approximately $6 million.

The Utility's interest income increased by approximately $99 million, or 130%, in 2006 compared to 2005, primarily due to an increase in interest earned on escrow related to Disputed Claims, the FERC's approval of the Utility's 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 in 2006, as compared to 2005, on short-term investments as a result of lower short-term investment balances.

The Utility's interest income in 2008 will be primarily affected by changes in the amount of escrowed funds related to Disputed Claims and interest rate levels.

Interest Expense

The Utility's interest expense increased by approximately $22 million, or 3%, in 2007 compared to 2006, primarily due to an approximately $19 million increase in interest expense related to Disputed Claims primarily due to an increase in the interest rate. (See Note 15 of the Notes to the Consolidated Financial Statements.) In addition, interest expense related to $1.2 billion in long-term debt issued in 2007 and variable rate pollution control bond loan agreements increased by approximately $40 million. These increases were partially offset by a reduction of approximately $34 million in the interest expense related to the ERBs and RRBs as their balances decline. In addition, other interest expense, including lower interest expense on balances in certain regulatory balancing accounts, decreased approximately $3 million.

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 Claims, interest expense associated with the ERBs, and accrued interest on higher balances in certain regulatory balancing accounts. Increased interest rates associated with these accounts also contributed to this higher interest expense. These increases were partially offset by lower interest expense on the declining balance of RRBs.

The Utility's interest expense in 2008 will be impacted by changes in interest rates as the Utility's short-term debt and a portion of its long-term debt bear variable interest rates, as well as by changes in the amount of debt, including debt expected to be issued in subsequent periods to finance capital expenditures. (See "Liquidity and Financial Resources" below.)

Income Tax Expense

The Utility's income tax expense decreased by approximately $31 million, or 5%, in 2007 compared to 2006, primarily due to a decrease of approximately $29 million as a result of fixed asset related tax deductions, mainly due to an increase in tax-deductible decommissioning expense in 2007 compared to 2006. The effective tax rates were 35.8% and 38.0% for 2007 and 2006, respectively.

The Utility's income tax expense increased by approximately $28 million, or 5%, in 2006 compared to 2005, primarily due to an increase in pre-tax income of $79 million for 2006. The effective tax rate was 38.0% for both 2006 and 2005.

PG&E CORPORATION, ELIMINATIONS, AND OTHER

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. PG&E Corporation's interest expense relates to its 9.50% Convertible Subordinated Notes and is not allocated to affiliates.

There were no material changes to PG&E Corporation's operating income in 2007 compared to 2006 and in 2006 compared to 2005.

Income Tax Benefit

PG&E Corporation's income tax benefit in 2007 decreased approximately $16 million, or 33%, compared to 2006, primarily due to a tax benefit booked in 2006 related to capital losses carried forward and used in PG&E Corporation's 2005 consolidated federal and state income tax returns with no comparable benefit in 2007.

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 PG&E Corporation's 2005 consolidated federal and state income tax returns.

Discontinued Operations

In 2005, PG&E Corporation received additional information from its former subsidiary, NEGT, regarding PG&E Corporation's 2004 and 2003 federal income tax returns. As a result, PG&E Corporation recorded $13 million in income from discontinued operations in 2005. (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 may fluctuate as a result of seasonal demand for electricity and natural gas, energy commodity costs, collateral requirements, the timing and effect of regulatory decisions and financings, and the amount and timing of capital expenditures, 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. At December 31, 2007, PG&E Corporation and its subsidiaries had consolidated cash and cash equivalents of approximately $345 million and restricted cash of approximately $1.3 billion. At December 31, 2007, PG&E Corporation on a stand-alone basis had cash and cash equivalents of approximately $204 million; the Utility had cash and cash equivalents of approximately $141 million and restricted cash of approximately $1.3 billion. Restricted cash primarily consists of approximately $1.2 billion of cash held in escrow pending the resolution of the remaining Disputed Claims as well as deposits made under certain third-party agreements. PG&E Corporation and the Utility maintain separate bank accounts. PG&E Corporation and the Utility primarily invest their cash in money market funds.

PG&E Corporation and the Utility seek to maintain or strengthen their credit ratings in order to provide liquidity through efficient access to financial and trade credit, and to reduce financing costs. PG&E Corporation and the Utility also seek to maintain the Utility's CPUC-authorized capital structure, which includes a 52% common equity component. In 2007, Moody's upgraded the Utility's credit rating to A3, thereby terminating a provision in the Chapter 11 Settlement Agreement that had required the CPUC to authorize a minimum 52% common equity ratio and a minimum ROE for the Utility of 11.22% until the Utility received a credit rating of A3 from Moody's or A- from S&P. On December 20, 2007, the CPUC issued a decision maintaining the Utility's authorized ROE at 11.35% and its common equity component at 52% for 2008.

As of February 2008, PG&E Corporation's and the Utility's credit ratings from Moody's and S&P were as follows:

	Moody's	S&P
Utility		
Corporate credit rating	A3	BBB+
Senior unsecured debt	A3	BBB+
Credit facility	A3	BBB+
Pollution control bonds backed by letters of credit	Not rated	AA/A-1+
Pollution control bonds backed by bond insurance	A3 to Aaa	AA to AAA
Preferred stock	Baa2	BBB-
Commercial paper program	P-2	A-2
PG&E Energy Recovery Funding LLC		
Energy recovery bonds	Aaa	AAA
PG&E Corporation		
Corporate credit rating	Baa1	Not rated
Credit facility	Baa1	Not rated

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, 2007, PG&E Corporation had a credit facility totaling $200 million, which can be increased to $300 million, subject to obtaining commitments from existing or new lenders and satisfying other conditions. As of December 31, 2007, the Utility had a credit facility totaling $2.0 billion ("working capital facility"), which can be increased to $3.0 billion, subject to obtaining commitments from existing or new lenders and satisfying other conditions. During 2007, the Utility increased its borrowing capacity under its commercial paper program from $1.0 billion to $1.75 billion. As of December 31, 2007, the Utility had $165 million of letters of credit and $250 million of borrowings outstanding under its working capital facility. As of December 31, 2007, the Utility also had $270 million of outstanding commercial paper. In order to satisfy rating agency criteria, the Utility treats the amount of its outstanding commercial paper as a reduction to the amount available under its working capital facility. As authorized by the CPUC, the total amount of the Utility's short-term debt at any time cannot exceed $2 billion (plus up to an additional $500 million for specific contingencies). At December 31, 2007, the Utility had $1.3 billion of short-term debt capacity available (in addition to $500 million of debt capacity for specific contingencies).

In 2005, the Utility purchased a financial guaranty insurance policy to insure the regularly scheduled payment of principal and interest on $454 million of pollution control bonds series 2005 A-G ("PC2005 bonds") issued by the California Infrastructure and Economic Development Bank. In January 2008, the insurer's credit rating was downgraded and/or put on review for possible downgrade by several credit agencies. This has resulted in increases in interest rates for the PC2005 bonds, which rates are currently set at auction every 7 or 35 days. To minimize this interest rate exposure, the Utility intends to exercise its right to purchase the bonds in lieu of redemption and remarket the bonds when market conditions are more favorable. The purchase of the PC2005 bonds is expected to be financed through issuance of long-term debt.

As discussed below in "Capital Expenditures," the Utility expects that its capital expenditures will average approximately $3.4 billion over each of the next four years. Subject to additional CPUC authorization as needed, the Utility forecasts that it will issue an average of $1.4 billion of long-term debt annually for each of the next four years (2008–2011), primarily to finance forecasted capital expenditures. During 2007, the Utility issued $700 million principal amount of 5.80% 30-year Senior Notes and $500 million principal amount of 5.625% 10-year Senior Notes. As the level of Utility debt increases, the Utility anticipates that it will need to issue additional common equity to maintain the 52% CPUC-authorized common equity component of its capital structure. During 2007, PG&E Corporation made equity contributions totaling $400 million to the Utility to meet a portion of the Utility's forecasted equity needs. PG&E Corporation anticipates that it will contribute $2 billion to $2.5 billion of additional equity to the Utility over the next four years to maintain the Utility's CPUC-authorized capital structure.

PG&E Corporation anticipates that it will fund a portion of future equity infusions to the Utility from the proceeds of common stock issued (1) upon exercise of employee stock options, (2) to the trustee of PG&E Corporation's 401(k) plan for employee-participant accounts, and (3) under the PG&E Corporation Dividend Reinvestment and Stock Purchase Plan ("DRSPP"), which became effective on October 1, 2007. During the year ended December 31, 2007, PG&E Corporation issued 5,038,197 shares of common stock upon the exercise of employee stock options, for the account of 401(k) plan participants, and under its DRSPP, generating approximately $175 million of cash. PG&E Corporation also expects to issue additional common stock, debt, or other securities, depending on market conditions, to fund a portion of the Utility's future equity needs.

The amount and timing of the Utility's future financing needs will depend on various factors, including: (1) the timing and amount of forecasted capital expenditures and any incremental capital expenditures beyond those currently forecasted; (2) the amount of cash internally generated through normal business operations; and (3) the timing of the resolution of the Disputed Claims (upon settlement or the conclusion of the FERC and judicial proceedings) and the amount of interest on these claims that the Utility will be required to pay. (See Note 15 of the Notes to the Consolidated Financial Statements.) PG&E Corporation will continue to evaluate how to best fund the Utility's future equity needs considering such factors as the timing and amount of the Utility's future financings, market conditions, and available interest rates and credit terms.

In addition, PG&E Corporation may issue additional debt, equity, or other securities to finance potential capital investments.

DIVIDENDS

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 ratio range to ensure that equity funding is readily available to support capital investment needs. The Boards of Directors retain authority to change the companies' respective 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 2007, the Utility paid cash dividends to holders of various series of preferred stock in the aggregate amount of $14 million. In addition, on February 15, 2008, the Utility paid cash dividends of $3 million to holders of preferred stock.

During 2007, the Utility paid common stock dividends of $547 million. Approximately $509 million of this amount was paid to PG&E Corporation and the remaining amount was paid to PG&E Holdings, LLC, a wholly owned subsidiary of the Utility that holds approximately 7% of the Utility's common stock.

On March 16, 2007, the Board of Directors of PG&E Corporation declared its quarterly dividend at $0.36 per share, an increase of $0.03 per share over the previous level of $0.33 per share. During 2007, PG&E Corporation paid common stock dividends of $529 million, including approximately $35 million paid to Elm Power Corporation, a wholly owned subsidiary of PG&E Corporation that holds approximately 6% of PG&E Corporation's common stock. On January 15, 2008, PG&E Corporation paid common stock dividends of $137 million, including $9 million paid to Elm Power Corporation. On February 20, 2008, the Board of Directors of PG&E Corporation declared its quarterly dividend at $0.39 per share, an increase of $0.03 per share over the previous level of $0.36 per share, payable on April 15, 2008 to shareholders of record on March 31, 2008.

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 2007, 2006, and 2005 were as follows:

(in millions)	2007	2006	2005
Net income	$1,024	$ 985	$ 934
Adjustments to reconcile net income to net cash provided by operating activities	2,122	1,573	1,082
Other changes in operating assets and liabilities	(605)	19	350
Net cash provided by operating activities	$2,541	$2,577	$2,366

Net cash provided by operating activities decreased by approximately $36 million in 2007 from 2006. The decrease primarily relates to a decline in cash settlements from energy suppliers in 2007 as compared to 2006. This decrease was offset primarily by an increase in net income in 2007 as compared to 2006.

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

- The Utility paid approximately $500 million less in net tax payments in 2006 as compared to 2005.
- Deferred income taxes and tax credits decreased by 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 declined by approximately $140 million in 2006 as compared to 2005.

These increases were partially offset by the following:

- Approximately $290 million of pension contributions were made during 2006 but not in 2005.
- 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 $125 million in additional costs primarily related to power and gas procurement that were unpaid at the end of 2005, compared to the end of 2006, primarily due to higher gas prices during 2005.

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. The level of cash used in investing activities depends primarily upon the amount and type of construction activities, which can be influenced by the need to make electricity and natural gas reliability improvements as well as by storms and other factors.

The Utility's cash flows from investing activities for 2007, 2006, and 2005 were as follows:

(in millions)	2007	2006	2005
Capital expenditures	$(2,768)	$(2,402)	$(1,803)
Net proceeds from sale of assets	21	17	39
Decrease in restricted cash	185	115	434
Other investing activities, net	(103)	(156)	(29)
Net cash used in investing activities	$(2,665)	$(2,426)	$(1,359)

Net cash used in investing activities increased by approximately $239 million in 2007 compared to 2006, primarily due to an increase of approximately $370 million in capital expenditures for the SmartMeter™ installation project, generation facility spending, replacing and expanding gas and electric distribution systems, and improving the electric transmission infrastructure. (See "Capital Expenditures" below.)

Net cash used in investing activities increased by approximately $1 billion in 2006 compared to 2005, primarily due to approximately $600 million of capital expenditures related to software improvements, the SmartMeter™ project, generation facilities, the improvement of the gas and electric distribution system, and the improvement of the electric transmission infrastructure. In addition, the Utility released $300 million more cash from escrow in 2005 upon settlement of Disputed Claims than in 2006.

Financing Activities

The Utility's cash flows from financing activities for 2007, 2006, and 2005 were as follows:

(in millions)	2007	2006	2005
Borrowings under accounts receivable facility and working capital facility	$ 850	$ 350	$ 260
Repayments under accounts receivable facility and working capital facility	(900)	(310)	(300)
Net issuance (repayments) of commercial paper, net of discount of $1 million in 2007 and $2 million in 2006	(209)	458	–
Net proceeds from issuance of long-term debt	1,184	–	451
Net proceeds from issuance of energy recovery bonds	–	–	2,711
Long-term debt, matured, redeemed, or repurchased	–	–	(1,554)
Rate reduction bonds matured	(290)	(290)	(290)
Energy recovery bonds matured	(340)	(316)	(140)
Preferred stock dividends paid	(14)	(14)	(16)
Common stock dividends paid	(509)	(460)	(445)
Preferred stock with mandatory redemption provisions redeemed	–	–	(122)
Preferred stock without mandatory redemption provisions redeemed	–	–	(37)
Equity infusion from PG&E Corporation	400	–	–
Common stock repurchased	–	–	(1,910)
Other	23	38	65
Net cash provided by (used in) financing activities	$ 195	$(544)	$(1,327)

In 2007, net cash provided by financing activities increased by approximately $739 million compared to 2006. This was mainly due to the following factors:

- The Utility issued Senior Notes in March and December 2007 for net proceeds of approximately $690 million and $494 million, respectively, with no similar issuances in 2006.
- The Utility received equity infusions of $400 million from PG&E Corporation in 2007, with no similar infusions in 2006.
- The Utility borrowed $500 million more under its working capital facility in 2007 as compared to 2006.
- The Utility repaid $590 million more under its working capital and accounts receivable facilities in 2007 as compared to 2006.
- The Utility made net commercial paper repayments of approximately $209 million in 2007 as compared to net borrowings of $458 million in 2006.
- The Utility paid approximately $49 million more in common stock dividends in 2007 than in 2006.

In 2006, net cash used in 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 in 2006 with no similar issuance 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.
- The amount of ERBs that matured in 2006 was approximately $175 million greater than the amount that matured in 2005.
- The Utility borrowed $90 million more from the accounts receivable facility during 2006, as compared to 2005.
- The Utility redeemed $122 million of preferred stock in 2005 with no similar redemption in 2006.
- In 2005, the Utility redeemed $500 million and defeased $600 million of Floating Rate First Mortgage Bonds (redesignated as Senior Notes in April 2005). The Utility also repaid $454 million under certain reimbursement obligations that the Utility entered into in April 2004, when its plan of reorganization under Chapter 11 of the U.S. Bankruptcy Code became effective. There were no similar redemptions or repayments in 2006.

PG&E CORPORATION

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 Corporations' consolidated cash flows from operating activities for 2007, 2006, and 2005 were as follows:

(in millions)	2007	2006	2005
Net income	$1,006	$ 991	$ 917
Gain on disposal of NEGT (net of income tax benefit of $13 million in 2005)	–	–	13
Net income from continuing operations	1,006	991	904
Adjustments to reconcile net income to net cash provided by operating activities	2,141	1,611	1,122
Other changes in operating assets and liabilities	(601)	112	383
Net cash provided by operating activities	$2,546	$2,714	$2,409

In 2007, net cash provided by operating activities decreased by $168 million as compared to 2006. The decrease is primarily related to tax refunds received by PG&E Corporation in 2006 with no similar refunds received in 2007 and a decrease in the Utility's net cash provided by operating activities.

In 2006, 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.

Investing Activities

PG&E Corporation, on a stand-alone basis, did not have any material cash flows associated with investing activities in the years ended December 31, 2007, 2006, and 2005:

Financing Activities

PG&E Corporation's primary sources of financing funds, on a stand-alone basis, are dividends from the Utility, equity issuances, and external financing. PG&E Corporation's uses of cash, on a stand-alone basis, primarily relate to the payment of common stock dividends and common stock repurchases.

PG&E Corporation's cash flows from financing activities for 2007, 2006, and 2005 were as follows:

(in millions)	2007	2006	2005
Borrowings under accounts receivable facility and working capital facility	$ 850	$ 350	$ 260
Repayments under accounts receivable facility and working capital facility	(900)	(310)	(300)
Net issuance (repayments) of commercial paper, net of discount of $1 million in 2007 and $2 million in 2006	(209)	458	–
Net proceeds from issuance of long-term debt	1,184	–	451
Net proceeds from issuance of energy recovery bonds	–	–	2,711
Long-term debt matured, redeemed, or repurchased	–	–	(1,556)
Rate reduction bonds matured	(290)	(290)	(290)
Energy recovery bonds matured	(340)	(316)	(140)
Preferred stock with mandatory redemption provisions redeemed	–	–	(122)
Preferred stock without mandatory redemption provisions redeemed	–	–	(37)
Common stock issued	175	131	243
Common stock repurchased	–	(114)	(2,188)
Common stock dividends paid	(496)	(456)	(334)
Other	35	3	32
Net cash provided by (used in) financing activities	$ 9	$(544)	$(1,270)

During 2007, PG&E Corporation's consolidated net cash provided by financing activities increased by approximately $553 million compared to 2006. The decrease in cash used after consideration of the Utility's cash flows provided by financing activities was primarily due to the payment of $114 million in 2006 to settle obligations related to the 2005 repurchase of common stock, with no similar payments in 2007.

During 2006, PG&E Corporation's consolidated net cash used in 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 $114 million to settle obligations related to the 2005 stock repurchase.

CONTRACTUAL COMMITMENTS

The following table provides information about the Utility's and PG&E Corporation's contractual obligations and commitments at December 31, 2007. PG&E Corporation and the Utility enter into contractual obligations in connection with business activities. These future 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. (See Note 17 of the Notes to the Consolidated Financial Statements.)

		Payment due by period			
(in millions)	Total	Less than 1 year	1–3 years	3–5 years	More than 5 years
Contractual Commitments:					
Utility					
Purchase obligations:					
Power purchase agreements(1):					
Qualifying facilities	$17,185	$1,770	$3,248	$2,891	$ 9,276
Irrigation district and water agencies	479	83	164	107	125
Renewable contracts	8,783	245	672	1,026	6,840
Other power purchase agreements	716	238	386	79	13
Natural gas supply and transportation	1,446	1,181	244	21	–
Nuclear fuel	1,083	82	195	186	620
Preferred dividends(2)	70	14	28	28	–
Other commitments(3)	26	24	2	–	–
Pension and other benefits(4)	900	300	600	–	–
Operating leases	112	19	27	38	28
Long-term debt(5):					
Fixed rate obligations	13,910	368	1,303	1,161	11,078
Variable rate obligations	1,796	28	53	688	1,027
Other long-term liabilities reflected on the Utility's balance sheet under GAAP:					
Energy recovery bonds(6)	2,177	435	871	871	–
Capital lease obligations(7)	503	50	100	100	253
PG&E Corporation					
Long-term debt(5):					
Convertible subordinated notes	345	27	318	–	–

(1) This table does not include DWR allocated contracts because the DWR is currently legally and financially responsible for these contracts and payments. See Note 17 of the Notes to the Consolidated Financial Statements for the Utility's contractual commitments including power purchase agreements (including agreements with qualifying facility co-generators, irrigation districts, and water agencies and renewable energy providers), natural gas supply and transportation agreements, and nuclear fuel agreements.

(2) Preferred dividend estimates beyond five years are not included as these dividend payments continue in perpetuity.

(3) Includes commitments for telecommunications and information system contracts in the aggregate amount of approximately $6 million, vehicle leasing arrangements in the aggregate amount of $3 million, and SmartMeter™ contracts in the aggregate amount of approximately $17 million.

(4) 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. (See Note 14 of the Notes to the Consolidated Financial Statements.)

(5) Includes interest payments over the terms of the debt. Interest is calculated using the applicable interest rate and outstanding principal for each instrument with the terms ending at each instrument's maturity. (See Note 4 of the Notes to the Consolidated Financial Statements.)

(6) Includes interest payments over the terms of the bonds. (See Note 6 of the Notes to the Consolidated Financial Statements.)

(7) See 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, 2007, the Utility was committed to spending approximately $236 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.

The contractual commitments table above also excludes potential payments associated with unrecognized tax benefits accounted for under Financial Accounting Standards Board ("FASB") Interpretation No. 48 "Accounting for Uncertainty in Income Taxes," ("FIN 48"). On January 1, 2007, PG&E Corporation and the Utility adopted the provisions of

FIN 48. (See "Adoption of New Accounting Pronouncements" in Note 2 of the Notes to the Consolidated Financial Statements for a discussion of the impact of adoption and the unrecognized tax benefits balance as of December 31, 2007.) Due to the uncertainty surrounding tax audits, PG&E Corporation and the Utility cannot make reliable estimates of the amount and period of future payments to major tax jurisdictions related to FIN 48 liabilities. Matters relating to tax years that remain subject to examination are discussed in Note 11 of the Notes to the Consolidated Financial Statements.

CAPITAL EXPENDITURES

The Utility's investment in plant and equipment totaled $2.8 billion in 2007, $2.4 billion in 2006, and $1.9 billion in 2005. The Utility expects that capital expenditures will total approximately $3.6 billion in 2008 and forecasts that capital expenditures will average approximately $3.4 billion over each of the next four years. The Utility's weighted average rate base in 2007 was $16.8 billion. Based on the estimated capital expenditures for 2008 and 2009, the Utility projects a weighted average rate base of approximately $18.4 billion for 2008 and approximately $20.8 billion for 2009.

The Utility forecasts that it will make various capital investments in its electric and gas transmission and distribution infrastructure to maintain and enhance system reliability and customer service, to extend the life of or replace existing infrastructure, to add new infrastructure to meet already authorized growth, and to implement various initiatives designed to achieve operating and cost efficiencies. The Utility also is exploring obtaining regulatory approval for potential investments in electric transmission projects, including the proposed 500 kV Central California Clean Energy Transmission project and a proposed new high voltage transmission line to run between Northern California and British Columbia, Canada. In addition, as discussed below, the Utility has been incurring substantial capital expenditures in connection with projects that have already begun, including the construction or acquisition of new generation facilities and the installation of an advanced metering system.

PG&E Corporation also may make material investments in two natural gas transmission pipeline projects through 2011: the proposed 230-mile Pacific Connector Gas Pipeline that would begin at the proposed Jordan Cove liquefied natural gas ("LNG") terminal to be located in Coos Bay, Oregon and connect with the Utility's transmission system near Malin, Oregon, and the proposed 680-mile Ruby Pipeline that would begin in Wyoming and terminate at the Malin, Oregon interconnect, near California's northern border. PG&E Corporation, through its subsidiary, PG&E Strategic Capital, Inc., along with Fort Chicago Energy Partners, L.P. and Northwest Pipeline Corporation, have agreed to jointly pursue the development of the Pacific Connector Gas Pipeline which is dependent upon the development of the Jordan Cove LNG terminal by Fort Chicago Energy Partners, L.P. In September 2007, applications with the FERC were filed to request authorization to construct the proposed Pacific Connector Gas Pipeline and the Jordan Cove LNG terminal. It is expected that the FERC will issue a decision by the end of 2008. Assuming the required permits, regulatory approvals, and long-term capacity commitments for both the terminal and pipeline are timely received and that other conditions are timely satisfied, it is anticipated that the proposed LNG terminal and the proposed Pacific Connector Gas Pipeline could begin commercial operation in 2011. In December 2007, PG&E Corporation entered into a letter of intent with El Paso Corporation to acquire a 25.5 percent interest in El Paso Corporation's proposed Ruby Pipeline. PG&E Corporation's acquisition of an interest in the Ruby Pipeline project is subject to various conditions, including the negotiation and execution of the partnership documents. Subject to obtaining the required regulatory and other approvals, including the approvals of the boards of directors of PG&E Corporation and El Paso Corporation, and after obtaining necessary customer commitments, the Ruby Pipeline is anticipated to be in service in the first quarter of 2011. PG&E Corporation cannot predict whether the regulatory approvals and other conditions for development of the Pacific Connector Gas Pipeline and the Ruby Pipeline will be met.

SmartMeter™ Program

In July 2006, the CPUC approved the Utility's application to install an advanced metering infrastructure, known as the SmartMeter™ program, for virtually all of the Utility's electric and gas customers. This infrastructure results in substantial cost savings associated with billing customers for energy usage, and enables the Utility to measure usage of electricity on a time-of-use basis and to charge demand-response rates. The main goal of demand-response 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 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. Through 2007, the Utility has spent an aggregate of $253 million, including capital costs of $213 million, to install the SmartMeter™ system.

On December 12, 2007, the Utility filed an application with the CPUC requesting approval to upgrade elements of the SmartMeter™ program at an estimated cost of approximately $623 million, including approximately $565 million of capital expenditures. The Utility has proposed to install upgraded electric meters with associated devices that would offer an expanded range of service features for customers and increased operational efficiencies for the Utility. These upgraded electric meters and devices would provide energy conservation and demand response options for electric customers. In addition, the upgraded electric meters are designed to facilitate the Utility's ability to incorporate future advanced metering technology innovations in a timely and cost-effective manner. The Utility also requested that the CPUC authorize the Utility to recover the estimated costs of the upgrade through electric rates beginning in 2009. PG&E Corporation and the Utility cannot predict whether the CPUC will approve its application.

Diablo Canyon Steam Generator Replacement Project

In November 2005, the CPUC authorized the Utility to replace the steam generators at the two nuclear operating units at Diablo Canyon (Units 1 and 2). The CPUC authorized the Utility to recover costs of this project of up to $706 million from customers without further reasonableness review; if costs exceed this threshold, the CPUC authorized the Utility to recover costs of up to $815 million, subject to reasonableness review of the full amount. As of December 31, 2007, the Utility has spent approximately $300 million, including progress payments under contracts for the eight steam generators that the Utility has ordered. The Utility anticipates the future expenditures will be approximately $373 million. The Utility began installing four of the new steam generators in Unit 2 during the refueling outage that began in February 2008 and expects to complete installation in April 2008. The remaining new generators in Unit 1 are expected to be installed in 2009.

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 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 complaint in the Superior Court for the County of San Francisco against both the California Coastal Commission and the Utility alleging that the California Coastal 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 California Coastal Commission complies with the judgment that the court may render. The court denied the request for a permanent injunction in April 2007. Further proceedings on the complaint have been delayed at the request of all parties in support of ongoing discussions regarding informal resolution of the complaint. PG&E Corporation and the Utility believe that the permits were legally and validly approved and issued.

If the replacement of the steam generators in Unit 1 is delayed, the Utility could incur additional costs to operate and maintain the old steam generators in Unit 1 until they can be replaced, which would delay and extend project completion dates. If the Utility is not able to replace the generators in Unit 1, the Utility would be required to cease operations at Diablo Canyon Unit 1 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 four steam generators and a pro-rated profit up to the time the performance under the contracts is completed or the contracts are terminated. Based on the progress of the project and productive settlement discussion, the Utility does not expect to incur these additional costs. In the unlikely event that replacement of the generators in Unit 1 is halted or delayed, the Utility would request to recover in customer rates any additional costs.

New Generation Facilities

During 2007, the Utility was engaged in the development of the following generation facilities to be owned and operated by the Utility:

- **Gateway Generating Station** — In November 2006, the Utility acquired the equipment, permits, and contracts related to a partially completed 530-megawatt ("MW"), power plant in Antioch, California, referred to as the Gateway Generating Station ("Gateway"). The CPUC has authorized the Utility to recover estimated capital costs of approximately $370 million to complete the construction of the facility. During 2007, the Utility incurred approximately $119 million related to the Gateway project. The Utility estimates that it will complete construction of the Gateway facility and commence operations in 2009.
- **Colusa Power Plant** — In November 2006, the CPUC approved the purchase and sale agreement between the Utility and E&L Westcoast, LLC ("E&L Westcoast") under which E&L Westcoast had agreed to construct a 657-MW power plant in Colusa County, California ("Colusa Project") and, upon successful completion, transfer ownership to the Utility. The CPUC adopted an initial capital cost for the Colusa Project that equals the sum of the fixed contract costs, 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 Utility estimates that the cost to complete the Colusa Project will be approximately $673 million, including owner's costs. The CPUC authorized the Utility to adjust the initial capital costs 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. The forecasted initial capital cost of the Colusa Project will be trued up in the Utility's next GRC following the commencement of operations to reflect actual initial capital costs. The CPUC authorized the Utility to seek recovery of additional capital costs attributable to operational enhancements, but otherwise limited cost recovery to the initial capital cost estimate. The CPUC also ruled that in the event the final capital costs are lower than the initial estimate, half of the savings must be returned to customers. If actual costs exceed the cost limits (except for additional capital costs attributable to operational enhancements), the Utility would be unable to recover such excess costs. During 2007, the Utility incurred approximately $12 million related to the Colusa Project.

  In January 2008, the Utility acquired the assets related to the Colusa Project from E&L Westcoast after E&L Westcoast notified the Utility in November 2007 that it intended to terminate the purchase and sale agreement. On January 29, 2008, a proposed decision was issued that recommends that the CPUC issue a Certificate of Public Convenience and Necessity ("CPCN") to allow the Utility to begin the construction of the Colusa Project subject to the initial capital cost limits and operations and maintenance ratemaking as described above. Permitting or construction delays and project development or materials cost overruns could cause the project costs to exceed the CPUC-adopted cost limits. The Utility has signed a contract with a major equipment supplier and has given a limited notice to proceed to a contractor to begin engineering and procurement activities. Subject to the timely issuance of a CPCN, the issuance of other required permits, operational performance requirements, and other conditions, it is anticipated that the Colusa Project will commence operations in 2010.
- **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 costs and estimated owner's costs. The CPUC authorized the Utility to adjust the initial capital costs 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 costs will be trued up in the Utility's next GRC following the commencement of operations of the plant to reflect actual initial capital costs and all cost savings, if any. The Utility is authorized to seek recovery of additional capital costs that are attributable to operational enhancements, but the request will be subject to the CPUC's review. The Utility also is permitted to seek recovery of additional capital costs subject to a reasonableness review. 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 2010 at an estimated cost of approximately $239 million, of which approximately $4 million has been incurred since 2007.

On December 20, 2007, the CPUC approved, with modifications, the California investor-owned electric utilities' long-term electricity procurement plans covering 2007–2016. The CPUC's decision forecasts that the Utility will need to obtain an additional 800 to 1,200 MW of new generation by 2015 beyond the Utility's planned additions of renewable resources, energy efficiency, and demand reduction programs. The decision allows the utilities to acquire ownership of new conventional generation resources only through turnkey and engineering, procurement, and construction arrangements proposed by third parties. The decision prohibits the utilities from submitting bids for utility-build generation in their respective requests for offers ("RFOs") until questions can be resolved about how to compare utility-owned generation bids with bids from independent power producers. The decision also permits utility-owned generation projects to be proposed through a separate application outside of the RFO process in the following circumstances: (1) to mitigate market power demonstrated by the utility to be held by others, (2) to support a use of preferred resources, such as renewable energy sources, (3) to expand existing facilities, (4) to take advantage of a unique and fleeting opportunity (such as a bankruptcy settlement), and (5) to meet unique reliability needs. The decision allows the utilities to make flexible proposals for utility-owned generation ratemaking on a case-by-case basis by eliminating the 2004 CPUC limitations that prohibited the utilities from recovering construction costs in excess of their final bid price from customers but required the utilities to share half of any construction cost savings with customers.

PG&E Corporation and the Utility cannot predict whether any of this forecasted demand will be met through new utility-owned generation projects on which the Utility would be authorized to earn an ROE.

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 its contractual obligation to deliver electricity, then the Utility may find it necessary to procure electricity at current market prices, which may be higher than the contract prices. Credit-related losses attributable to receivables and electric and gas procurement activities from wholesale customers and counterparties are expected to be recoverable from customers through rates and are not expected to have a material impact on net income.

The Utility manages credit risk associated with its wholesale customers and counterparties by assigning credit limits based on evaluations of their financial conditions, net worth, credit ratings, 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 ties many energy contracts to 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 following table 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, 2007 and December 31, 2006:

(in millions)	Gross Credit Exposure Before Credit Collateral[1]	Credit Collateral	Net Credit Exposure[2]	Number of Wholesale Customers or Counterparties >10%	Net Exposure to Wholesale Customers or Counterparties >10%
December 31, 2007	$311	$91	$220	2	$111
December 31, 2006	$255	$87	$168	2	$113

(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.

(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 ("NRC"), the resolutions of which may affect the Utility's and PG&E Corporation's results of operations or financial condition.

2008 Cost of Capital Proceeding

On December 20, 2007, the CPUC issued a decision in its proceeding to set the 2008 capital structure and ROEs of the three California investor-owned electric utilities. The CPUC maintained the Utility's authorized ROE at 11.35%, comparable to the ROEs approved for the other utilities, and maintained the Utility's common equity component at 52%. The following table compares the authorized amounts for 2007 with the authorized amounts for 2008:

	2007 Authorized			2008 Authorized		
	Cost	Capital Structure	Weighted Cost	Cost	Capital Structure	Weighted Cost
Long-term debt	6.02%	46.00%	2.77%	6.05%	46.00%	2.78%
Preferred stock	5.87%	2.00%	0.12%	5.68%	2.00%	0.11%
Common equity	11.35%	52.00%	5.90%	11.35%	52.00%	5.90%
Return on rate base			8.79%			8.79%

In a second phase of the proceeding, the Utility has also proposed to replace the annual cost of capital proceeding with an annual cost of capital adjustment mechanism for the five-year period from 2009 through 2013. The mechanism would utilize an interest rate benchmark to trigger changes in the authorized cost of equity. If the change is more than 75 basis points, the cost of equity would be adjusted by one-half the change in the benchmark interest rate. The costs of debt and preferred stock would be trued up to their recorded values in each year. Other parties, including The Utility Reform Network ("TURN"), Utility Consumers' Action Network, Southern California Edison, and the CPUC's Division of Ratepayer Advocates ("DRA") have submitted proposals to continue the annual proceeding or adopt a biennial proceeding.

A final decision in the second phase is scheduled to be issued by April 24, 2008. PG&E Corporation and the Utility are unable to predict the outcome of this phase of the proceeding.

Spent Nuclear Fuel Storage Proceedings

As part of the Nuclear Waste Policy Act of 1982, Congress authorized the U.S. Department of Energy ("DOE") and electric utilities with commercial nuclear power plants to enter into contracts under which the DOE would be required to dispose of the utilities' spent nuclear fuel and high-level radioactive waste no later than January 31, 1998, in exchange for fees paid by the utilities. In 1983, the DOE entered into a contract with the Utility to dispose of nuclear waste from the Utility's two nuclear generating units at Diablo Canyon and its retired nuclear facility at Humboldt Bay ("Humboldt Bay Unit 3"). The DOE failed to develop a permanent storage site by January 31, 1998. The Utility believes that the existing spent fuel pools at Diablo Canyon (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.

Because the DOE failed to develop a permanent storage site, the Utility obtained a permit from the NRC to build an on-site dry cask storage facility to store spent fuel through at least 2024. After various parties appealed the NRC's issuance of the permit, the U.S. Court of Appeals for the Ninth Circuit issued a decision in 2006 requiring the NRC to issue a supplemental environmental assessment report on the potential environmental consequences in the event of a terrorist attack at Diablo Canyon, as well as to review other contentions raised by the appealing parties related to potential terrorism threats. In August 2007, the NRC staff issued a final supplemental environmental assessment report concluding there would be no significant environmental impacts from potential terrorist acts directed at the Diablo Canyon storage facility. On January 15, 2008, the NRC decided to hold hearings on whether it provided a complete list of the references upon which it relied to find that there would not be a significant environmental impact and whether it sufficiently addressed the impacts on land and the local economy of a potential terrorist attack. It is expected that the NRC will issue a final decision in the third quarter of 2008.

The Utility expects to complete the dry cask storage facility and begin loading spent fuel in 2008. If the Utility is unable to complete the dry cask storage facility, if operation of the facility is delayed beyond 2010, or 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 until such time as additional safe storage for spent fuel is made available.

The Utility and other nuclear power plant owners have sued the DOE for breach of contract. The Utility seeks to recover its costs to develop on-site storage at Diablo Canyon and Humboldt Bay Unit 3. In October 2006, the U.S. Court of Federal Claims found that the DOE had breached its contract and awarded the Utility approximately $42.8 million of the $92 million incurred by the Utility through 2004. The Utility appealed to the U.S. Court of Appeals for the Federal Circuit seeking to increase the amount of the award and challenged the U.S. Court of Federal Claims' finding that the Utility would have incurred some of the costs for the on-site storage facilities even if the DOE had complied with the contract. A decision on the appeal is expected by the end of 2008. The Utility will seek to recover costs incurred after 2004 in future lawsuits against the DOE. Any amounts recovered from the DOE will be credited to customers through rates.

PG&E Corporation and the Utility are unable to predict the outcome of this appeal or the amount of any additional awards that the Utility may receive. If the U.S. Court of Federal Claims' 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.

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 businesses. 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 that its reasonably incurred wholesale electricity procurement costs are recoverable through the ratemaking mechanism described below, 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 Core Procurement Incentive Mechanism ("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 the 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 from suppliers prior to the hour- and day-ahead CAISO scheduling timeframes, or in the real-time market. 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 real-time market. The CAISO currently administers a real-time wholesale market for the sale of electric energy. This market is used by the CAISO to fine tune the balance of supply and demand in real time.

Price risk is associated with the uncertainty of prices when buying or selling to reduce open positions (short or long positions). This price risk is mitigated by electricity price caps. The FERC has adopted a "soft" cap on energy prices of $400 per megawatt-hour ("MWh") that applies to the spot market (i.e., real-time, hour-ahead, and day-ahead markets) throughout the Western Electricity Coordinating Council area. (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.)

As part of the CAISO's Market Redesign and Technology Upgrade ("MRTU") initiative, the CAISO plans to implement a change to the day-ahead, hour-ahead, and real-time markets including new price "hard" caps of $500/MWh when MRTU begins, rising to $750/MWh after the twelfth month of MRTU, and finally to $1000/MWh after the twenty-fourth month. The CAISO has delayed the start date of MRTU several times and has indicated that it will not set a new date for commencement of MRTU until market participants have had an opportunity to test the final MRTU system functionality and have provided feedback to the CAISO.

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 or terminations 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.

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.

In December 2007, the DWR terminated a contract with Calpine Corporation to purchase 1,000 MW of base load power needed by the Utility's customers and replaced it with a 180 MW tolling arrangement. In addition, the DWR may try to terminate or renegotiate other long-term power purchase contracts it has entered into with other power suppliers. To the extent DWR does terminate or renegotiate other contracts, the Utility will be responsible for procuring additional electricity to meet its customers' demand, potentially 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 2007 through 2016. The Utility recovers the costs incurred under these contracts and other electricity procurement costs through retail electricity rates that are adjusted whenever the forecasted aggregate over-collections or under-collections of the Utility's procurement costs for the current year exceed 5% of the Utility's prior year electricity procurement revenues. On January 23, 2008, the Utility filed an application with the CPUC to adjust rates to recover the additional $531 million in net procurement costs that the Utility expects to incur in 2008 due to the termination of the contract between the DWR and Calpine Corporation, discussed above. Because the DWR's procurement costs will be lower due to the termination of this contract, the Utility also has requested that the CPUC reduce the corresponding amount of DWR procurement costs that the Utility collects from its customers on the DWR's behalf. The Chapter 11 Settlement Agreement provides that the Utility will recover its reasonable costs of providing utility service, including power procurement costs. 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.

Electric Transmission Congestion Rights

Among other features, the MRTU initiative provides that electric transmission congestion costs and credits will be determined between any two locations and charged to the market participants, including load serving entities ("LSEs"), taking energy that passes between those locations. The CAISO also will provide Congestion Revenue Rights ("CRRs") to allow market participants, including LSEs, to hedge the financial risk of CAISO-imposed congestion charges in the MRTU day-ahead market. The CAISO will release CRRs through an annual and monthly process, each of which includes both an allocation phase (in which LSEs receive CRRs at no cost) and an auction phase (priced at market, and available to all market participants).

The Utility has been allocated and has acquired via auction certain CRRs as of December 31, 2007 and anticipates acquiring additional CRRs through the allocation and auction phases prior to the MRTU effective date. The CRRs are accounted for as derivative instruments and will be recorded in PG&E Corporation's and the Utility's Consolidated Balance Sheets at fair value. Changes in the fair value of the CRRs will be deferred and recorded in regulatory accounts to the extent they are recoverable through rates.

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 did not approve the Utility's proposed electric portfolio gas hedging plan that was included in the Utility's long-term procurement plan. Instead, the CPUC deferred consideration of the proposal to another proceeding. The CPUC ordered the Utility to continue operating under the previously approved gas hedging plan. The expenses associated with the hedging plan are expected to be recovered through rates.

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, varying volumes of gas may be purchased in the monthly and, to a lesser extent, daily spot market to meet such seasonal demand. The Utility's cost of natural gas purchased for its core customers includes costs for the commodity, Canadian and interstate transportation, and intrastate gas transmission and storage.

Under the CPIM, the Utility's purchase costs for a fixed 12-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 75% 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.

On June 7, 2007, the CPUC issued a decision approving a long-term hedging program for the Utility's core gas purchases. The decision approved a settlement agreement between the Utility and three major consumer advocate groups that represent the interests of core customers, including the DRA, Aglet Consumer Alliance, and TURN. In addition, as part of the long-term core hedge program settlement, the Utility and the DRA agreed to modify the CPIM sharing provision for cost savings below the tolerance band to 20% shareholder and 80% customers, beginning with the 2007–2008 CPIM cycle (November 1, 2007 through October 31, 2008).

Under the decision, the long-term core hedge program will be in place for up to five years starting with the 2007–2008 winter season. The Utility consults with an advisory group, consisting of members of the three core gas consumer advocate groups, before submitting its annual hedging plan to the CPUC for approval. The Utility's hedging costs will be recovered from its core gas customers as long as the CPUC finds that the Utility implemented its hedges in accordance with the pre-approved plan. All costs and benefits associated with hedging purchases under the approved annual hedging plan will be accounted for outside the CPIM.

The Utility's filed core hedge plan prescribes the financial hedges that will be put in place on a rolling three-year basis (the current winter season and the next two subsequent winter seasons), consistent with pre-defined hedge program parameters. The CPUC approved the 2007–2008 winter season annual hedge plan on June 26, 2007. The Utility completed the execution of its hedge plan in the third quarter of 2007.

Nuclear Fuel

The Utility purchases nuclear fuel for Diablo Canyon through contracts with terms ranging from one to thirteen 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 rates 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 substantial costs through reservation charges. The reservation charges under such contracts typically cover approximately 65% of the Utility's total cost of service. 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 framework.

The Utility uses value-at-risk to measure the shareholders' exposure to price and volumetric risks resulting from variability in the price of and demand for natural gas transportation and storage services that could impact revenues due to changes in market prices and customer demand. 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 that may not adequately capture portfolio risk.

The Utility's value-at-risk calculated under the methodology described above was approximately $31 million and $26 million at December 31, 2007 and December 31, 2006, respectively. The Utility's high, low, and average value-at-risk during the years ended December 31, 2007 and December 31, 2006 were approximately $39 million, $21 million, and $29 million, and $41 million, $22 million, and $33 million, respectively.

Convertible Subordinated Notes

At December 31, 2007, PG&E Corporation had outstanding approximately $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 approximately 18,558,059 shares of common stock of PG&E Corporation, at a conversion price of $15.09 per share. The conversion price is subject to adjustment for significant changes 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. PG&E Corporation paid "pass-through dividends" to the holders of Convertible Subordinated Notes of approximately $26 million in 2007 and approximately $7 million on January 15, 2008. Since no holders of the Convertible Subordinated Notes exercised the one-time right to require PG&E Corporation to repurchase the Convertible Subordinated Notes on June 30, 2007, PG&E Corporation reclassified the Convertible Subordinated Notes as a noncurrent liability (in Noncurrent Liabilities – Long-Term Debt) in the accompanying Consolidated Balance Sheets effective as of that date.

In accordance with Statement of Financial Accounting Standard No. 133 "Accounting for Derivative Instruments and Hedging Activities" 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. Dividend participation rights are recognized as financing cash flows on PG&E Corporation's Consolidated Statements of Cash Flows. Changes in the fair value are recognized in PG&E Corporation's Consolidated Statements of Income as a non-operating expense or income (in Other Income, Net). At December 31, 2007 and December 31, 2006, the total estimated fair value of the dividend participation rights component, on a pre-tax basis, was approximately $62 million and $79 million, respectively, of which $25 million and $23 million, respectively, was classified as a current liability (in Current Liabilities – Other) and $37 million and $56 million, respectively, was classified as a noncurrent liability (in Noncurrent Liabilities – Other).

INTEREST RATE RISK

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, 2007, 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 approximately $3 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, "Accounting for the Effects of Certain Types of Regulation" ("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. In addition, amounts that are probable of being credited or refunded to customers in the future must be recorded as regulatory liabilities. Regulatory assets and liabilities are recorded when it is probable, as defined in SFAS No. 5 "Accounting for Contingencies" ("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, proposed regulatory decisions, final regulatory orders, and the strength or status of applications for rehearing 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, 2007, PG&E Corporation and the Utility reported regulatory assets (including current regulatory balancing accounts receivable) of approximately $5.2 billion and regulatory liabilities (including current balancing accounts payable) of approximately $5.1 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, 2007, accrued unbilled revenues totaled $750 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, 2007, the Utility's accrual for undiscounted and gross environmental liabilities was approximately $528 million. The Utility's undiscounted future costs could increase to as much as $834 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 and gross environmental liabilities is representative of future events that are likely to occur. In determining maximum undiscounted future costs, events that are possible but not probable 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" ("SFAS No. 143"), and FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations – An Interpretation of SFAS No. 143" ("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 ("ARO") is 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 mark-up 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 No. 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 ARO by approximately 1.26%. Similarly, an increase in the discount rate by 25 basis points would decrease ARO by 0.95%. At December 31, 2007, the Utility's estimated cost of retiring these assets is approximately $1.6 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.

On January 1, 2007, PG&E Corporation and the Utility adopted the provisions of FIN 48. (See Note 2 of the Notes to the Consolidated Financial Statements for further discussion.)

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" ("SFAS No. 158"), SFAS No. 87, "Employers' Accounting for Pensions" ("SFAS No. 87"), and other benefits under SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other than Pensions" ("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 $117 million in 2007, $185 million in 2006, and $176 million in 2005 in accordance with the provisions of SFAS No. 87. PG&E Corporation's and the Utility's recorded expense for other postretirement benefits totaled $44 million in 2007, $49 million in 2006, and $55 million in 2005 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.

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 fully-funded status by 2010. In March 2007, the CPUC extended the terms of the decision for one additional year, through 2010. PG&E Corporation and the Utility made total pension contributions of approximately $139 million in 2007 and expect to make total contributions of approximately $176 million annually for the years 2008, 2009, and 2010. PG&E Corporation and the Utility made total contributions of approximately $38 million in 2007 related to their other postretirement benefit plans and expect to make contributions of approximately $58 million annually for the years 2008, 2009, and 2010.

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, absolute return securities, and fixed income securities. Investment securities are exposed to various risks, including interest rate risk, credit risk, 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's Retirement Plan, the assumed return of 7.4% compares to a ten-year actual return of 7.9%.

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, 2007. 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 2007 Pension Costs	Increase in Projected Benefit Obligation at December 31, 2007
Discount rate	(0.5)%	$22	$612
Rate of return on plan assets	(0.5)%	44	–
Rate of increase in compensation	0.5%	18	129

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 2007 Other Post-retirement Benefit Costs	Increase in Accumulated Benefit Obligation at December 31, 2007
Health care cost trend rate	0.5%	$6	$32
Discount rate	(0.5)%	7	76

ACCOUNTING PRONOUNCEMENTS ISSUED BUT NOT YET ADOPTED

Fair Value Measurements

On January 1, 2008, PG&E Corporation and the Utility adopted the provisions of SFAS No. 157, "Fair Value Measurements" ("SFAS No. 157"), which defines fair value measurements and implements a hierarchical disclosure.

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," or the "exit price." Accordingly, an entity must now determine the fair value of an asset or liability based on the assumptions that market participants would use in pricing the asset or liability, not those of the reporting entity itself. The identification of market participant assumptions provides a basis for determining what inputs are to be used for pricing each asset or liability. Additionally, SFAS No. 157 establishes a fair value hierarchy which gives precedence to fair value measurements calculated using observable inputs to those using unobservable inputs. Accordingly, the following levels were established for each input:

- **Level 1** — "Inputs that are quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date."
- **Level 2** — "Inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly or indirectly."
- **Level 3** — "Unobservable inputs for the asset or liability." These are inputs for which there is no market data available, or observable inputs that are adjusted using Level 3 assumptions.

SFAS No. 157 requires entities to disclose financial fair-valued instruments according to the above hierarchy in each reporting period after implementation. The standard deferred the disclosure of the hierarchy for certain non-financial instruments to fiscal years beginning after November 15, 2008.

SFAS No. 157 should be applied prospectively except if certain criteria are met. CRRs held by the Utility meet the criteria and will be adjusted upon adoption to comply with SFAS No. 157 requirements. CRRs allow market participants, including LSEs, to hedge the financial risk of CAISO-imposed congestion charges in the MRTU day-ahead market. PG&E Corporation and the Utility are still evaluating the impact of the adjustment to price risk management assets and regulatory liabilities on their Consolidated Balance Sheets. The costs associated with procurement of CRRs are currently being recovered in rates or are probable of recovery in future rates; therefore, the adoption of SFAS No. 157 will not have an impact on net income.

Fair Value Option

In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities" ("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 do not expect the adoption of SFAS No. 159 to materially impact the financial statements.

Amendment of FASB Interpretation No. 39

In April 2007, the FASB issued FASB Staff Position on Interpretation 39, "Amendment of FASB Interpretation No. 39" ("FIN 39-1"). Under FIN 39-1, a reporting entity is permitted to offset the fair value amounts recognized for cash collateral paid or cash collateral received against the fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting arrangement. FIN 39-1 is effective for fiscal years beginning after November 15, 2007, and will affect the Utility's Consolidated Balance Sheets as of March 31, 2008. The impact of FIN 39-1 on PG&E Corporation's and the Utility's balance sheets is currently being evaluated. PG&E Corporation and the Utility do not expect any earnings impact as a result of the adoption of the amendment, as FIN 39-1 only affects the balance sheet.

TAXATION MATTERS

See Note 11 of the Notes to the Consolidated Financial Statements for discussion of 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 environmental laws. Under federal and California laws, the Utility may be responsible for remediation of hazardous substances at former manufactured gas plant sites, power plant sites, and sites used by the Utility for the storage, recycling, or disposal of potentially hazardous materials, 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. 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 and gross environmental remediation liability of approximately $528 million at December 31, 2007 and approximately $511 million at December 31, 2006. The $528 million accrued at December 31, 2007 consists of:

- Approximately $235 million for remediation at the Hinkley and Topock natural gas compressor sites;
- Approximately $90 million related to remediation at divested generation facilities;
- Approximately $152 million related to remediation costs for the Utility's generation and other facilities, 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); and
- Approximately $51 million related to remediation costs for the fossil decommissioning sites.

Of the approximately $528 million environmental remediation liability, approximately $132 million has been included in prior rate setting proceedings. The Utility expects that an additional amount of approximately $306 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 $834 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 $834 million does not include an estimate for any potential costs of remediation at former manufactured gas plant sites owned by others, unless the Utility has assumed liability for the site, the current owner has asserted a claim against the Utility, or the Utility has otherwise determined it is probable that a claim will be asserted.

In July 2004, the U.S. Environmental Protection Agency ("EPA") published regulations under Section 316(b) of the Clean Water Act that apply to existing electricity generation facilities that use over 50 million gallons of water per day, which typically include some form of "once-through" cooling in which water from natural bodies of water is used to cool a generating facility and the heated water is discharged back into the source. The Utility's Diablo Canyon power plant is among an estimated 539 generation facilities nationwide that are affected by this rulemaking. The EPA regulations are intended to reduce impacts to aquatic organisms by establishing a set of performance standards for cooling water intake structures. These regulations allow site-specific compliance measures if a facility's cost of compliance is significantly greater than either the benefits to be achieved or the compliance costs considered by the EPA. The EPA regulations also allow the use of environmental mitigation or restoration to meet compliance requirements in certain cases. In response to the EPA regulations, in June 2006, the

California State Water Resources Control Board ("Water Board") published a draft policy for California's implementation of Section 316(b) that proposes to eliminate the EPA's site-specific compliance options, although the draft state policy would permit environmental restoration as a compliance option for nuclear facilities if the installation of cooling towers would conflict with a nuclear safety requirement. Various parties separately challenged the EPA's regulations in court, and the cases were consolidated in the U.S. Court of Appeals for the Second Circuit ("Second Circuit"). In January 2007, the Second Circuit remanded significant provisions of the regulations to the EPA for reconsideration and held that a cost-benefit test could not be used to comply with performance standards or to obtain a variance from the standards. The Second Circuit also ruled that environmental restoration cannot be used to comply with the standard. Petitions requesting U.S. Supreme Court review of the Second Circuit decision are pending, and the EPA has suspended its regulations. It is uncertain when the EPA will issue revised regulations, whether the Supreme Court will accept review of the Second Circuit decision, how judicial developments will affect the EPA's revised regulations, how judicial developments and the EPA's revised regulations will affect the Water Board's proposed policy, and when the Water Board will issue its final policy. Depending on the nature of the final regulations that may ultimately be adopted by the EPA or the Water Board, the Utility may incur significant capital expense to comply with the final regulations, which the Utility would seek to recover through rates. If either the final regulations adopted by the EPA or the Water Board require the installation of cooling towers at Diablo Canyon, and if installation of such cooling towers is not technically or economically feasible, the Utility may be forced to cease operations at Diablo Canyon.

LEGAL MATTERS

PG&E Corporation and the Utility are subject to various laws and regulations and, in the normal course of business, PG&E Corporation and the Utility are named as parties in a number of claims and lawsuits.

In accordance with SFAS No. 5, 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 matter. 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 Current Liabilities – Other in the Consolidated Balance Sheets, and totaled approximately $78 million at December 31, 2007 and approximately $74 million at December 31, 2006.

After considering the above accruals, PG&E Corporation and the Utility do not expect that losses associated with legal matters will have a material impact on their financial condition 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 adopting an expansive interpretation of PG&E Corporation's obligations under this condition, including the requirement that PG&E Corporation "infuse the Utility with all types of capital necessary for the Utility to fulfill its obligation to serve." The CPUC's interpretation of these obligations could require PG&E Corporation to infuse the Utility with significant capital in the future, or could prevent distributions from the Utility, either of which could materially restrict PG&E Corporation's ability to meet other obligations or execute its business strategy.

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

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. The complaints 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 holding company conditions. The complaints 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 in this matter could have a material, adverse affect on PG&E Corporation's financial condition, results of operations, and cash flows.

PG&E Corporation's proposed investments in new natural gas pipeline projects may not materialize and PG&E Corporation may be unable to finance such investments on favorable terms or rates.

The completion of PG&E Corporation's anticipated capital investment projects in proposed new natural gas pipelines projects, as discussed in "Capital Expenditures" above, is subject to various regulatory approvals and many construction and development risks, including risks related to financing, obtaining and complying with the terms of permits, meeting construction budgets and schedules, meeting environmental performance standards, and obtaining capacity commitments from shippers. Many of these conditions must be satisfied by PG&E Corporation's investment partners and PG&E Corporation will not be able to control whether the conditions are satisfied.

PG&E Corporation's ability to access the capital markets and the costs and terms of available financing depend on many factors, including changes in PG&E Corporation's credit ratings, changes in the federal or state regulatory environment affecting energy companies, and general economic and market conditions. There can be no assurance that PG&E Corporation will be able to obtain financing with favorable terms and conditions, or at all.

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 of and on the capital invested in its utility assets, including the long-term debt and equity issued to finance their acquisition. Unanticipated changes in operating expenses or capital expenditures can 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, 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 another 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, 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 that the CPUC will not otherwise take or fail to take actions that would be 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 and the potential restructuring of the CPUC's resource adequacy program.

In response to the electricity market manipulation that occurred during the 2000–2001 energy crisis and the underlying need for improved congestion management, the CAISO has undertaken an initiative called Market Redesign and Technology Upgrade, referred to as MRTU, to implement a new day-ahead wholesale electricity market and to improve electricity grid management reliability, operational efficiencies, and related technology infrastructure. MRTU will add significant market complexity and will require major changes to the Utility's systems and software interfacing with the CAISO. It is uncertain when MRTU will become effective. Although the CPUC has authorized the Utility to record its related incremental capital costs and expenses, the Utility's ability to recover these recorded amounts from customers will be subject to a future CPUC proceeding where the reasonableness of amounts recorded will be reviewed.

Among other features, the MRTU initiative provides that electric transmission congestion costs and credits will be determined between any two locations and charged to the market participants, including LSEs like the Utility, that take energy that passes between those locations. The CAISO also will provide CRRs to allow market participants, including LSEs, to hedge the financial risk of CAISO-imposed congestion charges in the MRTU day-ahead market. The CAISO will release CRRs through an annual and monthly process, each of which includes both an allocation phase (in which LSEs receive CRRs at no cost) and an auction phase (priced at market, and available to all market participants). The Utility has been allocated and has acquired via auction certain CRRs as of December 31, 2007 and anticipates acquiring additional CRRs through the allocation and auction phases prior to the MRTU effective date.

In addition, it is anticipated that the CPUC will issue a decision in May 2008 that may change its current resource adequacy program which requires all LSEs to maintain physical generating capacity adequate to meet its load requirements, including, but not limited to, peak demand and planning and operating reserves, deliverable to locations and at times as may be necessary to provide reliable electric service. If the CPUC makes comprehensive changes to the program, such as replacing the current structure with a centralized capacity market similar to the organized capacity markets that operate in the Eastern United States, the Utility may be required to procure some or all of the capacity it needs through a centralized market instead of through bilateral contracts. It is uncertain how the Utility's resource adequacy obligations and related costs may change. Implementation of a centralized capacity market would require changes to the CAISO tariff and FERC approval.

If the Utility incurs significant costs to implement MRTU, including the costs associated with CRRs, that are not timely recovered from customers; if the new market mechanisms created by MRTU result in any price/market flaws that are not promptly and effectively corrected by the market mechanisms, the CAISO, or the FERC; if the Utility's CRRs are not sufficient to hedge the financial risk associated with its CAISO-imposed congestion costs under MRTU; if either the CAISO's or the Utility's MRTU-related systems and software do not perform as intended or if the CPUC adopts comprehensive changes to its resource adequacy program that materially affect the Utility's obligations under that program, the current cost of capacity, or the means by which the Utility procures that capacity, 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 identify and implement new initiatives to achieve operating and capital cost savings and operating efficiencies to compensate for the lower levels of realized and forecasted benefits from implemented initiatives and to offset potential increases in operating and maintenance costs to improve the safety and reliability of its electric and natural gas distribution systems.

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. The cost of many of these initiatives is substantial, with savings expected to be realized in later years. The settlement of the Utility's 2007 GRC contemplated a certain level of benefits 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, to the extent that contemplated cost savings are not realized, earnings available for shareholders would be reduced. Although the Utility has realized many of the projected benefits, actual results from some of these initiatives have been less than forecasted. One major initiative involving new work processes, information systems, and technology has resulted in significant delays in responding to customer requests for new service, although the Utility is attempting to remedy the problems. If the Utility is unable to identify and implement new cost-saving initiatives, or promptly fix the problems with customer requests for new service, PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows would be adversely affected.

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 the SmartMeter™ advanced metering infrastructure project for residential and small commercial customers. This project, which is expected to be completed by the end of 2011, involves the installation of approximately 10 million advanced electricity and gas meters throughout the Utility's service territory. 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 CPUC authorized the Utility to recover $1.74 billion in estimated project costs, including an estimated capital cost of $1.4 billion and approximately $54.8 million for costs related to marketing a new demand response rate based on critical peak pricing. If additional costs exceed $100 million, the additional costs will be subject to the CPUC's reasonableness review. In December 2007, the Utility has requested the CPUC to approve certain upgrades to the advanced metering infrastructure and to authorize related revenue requirements of approximately $623 million, including approximately $565 million of forecasted capital expenditures.

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 cannot 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 must procure electricity to meet customer demand, plus applicable reserve margins, not satisfied from the Utility's own generation facilities and existing electricity contracts. 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.

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 or terminations 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 were 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 customers who purchase electricity from alternate energy providers (referred to as "direct access" customers) or customers of community choice aggregators (see below) decided to return to receiving bundled services from the Utility.

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 flow of the Utility and PG&E Corporation.

Alternatively, the Utility would be in a long position if the number of Utility customers declined. On February 28, 2008, the CPUC is scheduled to vote on a proposed decision that concludes that the CPUC does not have the authority to reinstate the ability of the Utility's customers to become direct access customers because the DWR still supplies power under the contracts it executed during the energy crisis. The proposed decision states that the CPUC will proactively investigate how the DWR can terminate its obligations under the power contracts, by assignment or otherwise, to hasten the reinstatement of direct access. 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. No cities or counties are currently operating as community choice aggregators, but the San Joaquin Valley Power Authority has filed an implementation plan and stated that it intends to begin operating in 2008. In addition, the Utility could lose customers, or experience lesser demand, because of increased self-generation. The risk of loss of customers and decreased demand 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 or reduction of demand by 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. The CPUC has authorized the Utility to make substantial 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 CPUC also has authorized the Utility to make capital investments in several new generation 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 net income.

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. Third-party developers of generation projects to be owned and operated by the Utility also face these risks. In addition, the Utility 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 their net income over time. Although recorded capital costs may be trued up in the next GRC, there can be no assurance that the CPUC or the FERC will allow such costs to be included in rate base.

If the Utility cannot 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 the Utility fails to acquire sufficient capacity to meet these 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 for specific regions in which locally-situated electricity capacity may be needed due to transmission constraints. The CPUC set the penalty for failure to meet local resource adequacy requirements at $40 per kW-year. In addition to penalties, the CAISO can require LSEs that fail to meet their resource adequacy requirements to pay the CAISO's cost of buying electricity capacity to fulfill the LSEs' resource adequacy target levels.

In addition, the Renewables Portfolio Standard ("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 CPUC has encouraged the utilities to pursue the goal to meet 33% of their load with renewable resources by 2020. It is also possible that the RPS requirement may become higher in the future through legislative action or through a ballot initiative.

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. Also, the Utility's natural gas transportation facilities could risk 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 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 and may result in stranded investment capital, loss of customer growth, and additional barriers to cost recovery. For example, the South San Joaquin Irrigation District ("SSJID") has sought approval from the local agency formation commission to serve portions of the Utility's service territory within San Joaquin County. Although SSJID's plans were rejected by the local agency formation commission in 2006, SSJID has appealed the rejection and has indicated that it intends to pursue its efforts, and has stated that it intends to condemn the Utility's electric distribution system within SSJID's boundaries.

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 were allowed to pass to the Utility their cost of the natural gas they purchase as fuel for their generating facilities, 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 significantly increase, public pressure, other regulatory influences, governmental influences, or other factors could constrain the CPUC from authorizing timely recovery of the Utility's costs from customers. If the Utility cannot recover a 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 cannot 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, the realization of which can 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. These risks include:

- 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;
- equipment failure;
- failure of the Utility's computer information systems, including those relating to operations or financial information such as customer billing;
- labor disputes, workforce shortage, and 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, and terrorist activities; and
- other events or hazards.

In particular, the Utility is undertaking a thorough review of its operating practices and procedures in light of certain recent transformer failures, issues regarding mandated gas leak surveys, and the discovery that some natural gas maintenance records did not accurately reflect field conditions. The Utility has determined that some of its operating procedures need improvement, that other operating procedures are not consistently followed, and that there is a need for improved training and supervision of some operations personnel. The Consumer Protection and Safety Division of the CPUC also is conducting an informal investigation of the Utility's natural gas distribution maintenance practices. Depending on the results of the Utility's review, the Utility may incur costs, not included in forecasts used to set rates in the GRC, to address any identified issues associated with the reliability and safety of the electric and natural gas distribution systems. PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows would be materially adversely affected if the Utility were to incur material costs or other material liabilities in connection with these operational issues that were not recoverable through rates.

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.

Also, the Utility's workforce is aging and many employees will become eligible to retire within the next few years. Although the Utility has undertaken efforts to recruit and train new field service personnel, there can be no assurance that these efforts will be successful. The Utility may be faced with a shortage of experienced and qualified personnel that could negatively impact the Utility's operations as well as its financial condition and results of operations. Finally, during 2008, the Utility also will re-negotiate major contracts with two of its labor unions, the International Brotherhood of Electrical Workers, Local 1245, AFL-CIO covering 10,971 employees at December 31, 2007 and the Engineers and Scientists of California, IFPTE Local 20, AFL-CIO and CLC covering 1,922 employees at December 31, 2007. The final terms of these new contracts will determine the impact of labor costs on the Utility's future results of operations as the collective bargaining agreements cover 12,929 of the Utility's total 19,785 employees at December 31, 2007. In addition, it is possible that some of the remaining non-represented Utility employees will join one of these unions in the future.

The Utility's future operations may be impacted by climate change that may have a material impact on the Utility's financial condition and results of operations.

There is substantial uncertainty about the potential impacts of climate change on the Utility's electricity and natural gas operations and whether climate change is responsible for increased frequency and severity of hot weather, including potentially decreased hydroelectric generation resulting from reduced runoff from snow pack and increased sea level along the Northern California coastal area. If climate change reduces the Utility's hydroelectric generation capacity, there will be a need for additional generation capacity even if there is no change in average load. The impact of events caused by climate change could range widely, with highly localized to worldwide effects, and under certain conditions 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. Even the less extreme events could result in lower revenues or increased expenses, or both; increased expenses may not be fully recovered through rates or other means in a timely manner or at all, and decreased revenues may negatively impact otherwise anticipated rates of return.

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. 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 statewide limit on the emission of greenhouse gases that must be achieved by 2020 and prohibits LSEs, 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 regulations and potential federal legislation may subject the Utility to significant additional costs. The Utility already has significant liabilities (currently known, unknown, actual, and potential) related to environmental contamination at current and former 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 future capital expenditures 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 accrued 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 flow 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 source, adversely affecting its financial condition, results of operations, and cash flow.

Operating and decommissioning 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 when their licenses expire. The Utility maintains insurance 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 the Utility's Diablo Canyon facility, 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. If they do not comply, the NRC can impose fines or 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 into several purchase agreements for nuclear fuel, with terms ranging from one to thirteen years, there is no assurance the Utility will be able to enter into similar agreements in the future on terms that the CPUC will find reasonable.

The NRC operating licenses for Diablo Canyon require sufficient storage capacity for the radioactive spent fuel it produces. 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 and begin loading spent fuel in 2008. The NRC is still considering issues that were raised by various parties who appealed the NRC's issuance of the permit. (See "Regulatory Matters – Spent Nuclear Fuel Storage Proceeding" above.) 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. If the Utility is unable to complete the dry cask storage facility, or if operation of the facility 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. That curtailment or cessation of operations may be continued until such time as additional safe storage for spent fuel is made available. 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.

Furthermore, certain aspects of the Utility's nuclear operations are subject to other federal, state, and local regulatory requirements that are overseen by other federal, state, or local agencies. For example, as discussed above under "Environmental Matters," there is substantial uncertainty concerning the final form of federal and state regulations to implement Section 316(b) of the Clean Water Act. Depending on the nature of the final regulations that may ultimately be adopted by the EPA or the Water Board, the Utility may incur significant capital expense to comply with the final regulations, which the Utility would seek to recover through rates. If either the federal or state final regulations require the installation of cooling towers at Diablo Canyon, and if installation of such cooling towers is not technically or economically feasible, the Utility may be forced to cease operations at Diablo Canyon.

Various parties, including the local community, environmental, political, or other groups may participate, or seek to intervene, in regulatory proceedings. In addition, these groups have in the past and may in the future challenge certain aspects of the Utility's nuclear operations through judicial proceedings.

If the CPUC prohibits 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 flow would be materially adversely affected.

The Utility is subject to penalties for failure to comply with federal, state, or local statutes and regulations. Changes in the political and regulatory environment could cause federal and state statutes, 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, regulations, rules, tariffs, and orders of the CPUC, the FERC, the NRC, and other regulatory agencies relating to the aspects of its electricity and natural gas utility operations that fall within the jurisdictional authority of such agencies. These include customer billing, customer service, affiliate transactions, vegetation management, and safety and inspection practices. The Utility is subject to fines and penalties for failure to comply with applicable statutes, regulations, rules, tariffs, and orders. For example, under the Energy Policy Act of 2005, the FERC can impose penalties (up to $1,000,000 per day per violation) for failure to comply with mandatory electric reliability standards.

In addition, there is risk that these statutes, regulations, rules, tariffs, and orders may become more stringent and difficult to comply with in the future, or that their interpretation and application may change over time and that the Utility will be determined to have not complied with such new interpretations. If this occurs, the Utility could be exposed to increased costs to comply with the more stringent requirements or new interpretations and to potential liability for customer refunds, penalties, or other amounts. If it is determined that the Utility did not comply with applicable statutes, regulations, 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 flow would be materially adversely affected.

The Utility also must 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 often have 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.

If the Utility cannot obtain, renew, or comply with necessary governmental permits, authorizations, or licenses, or if the Utility cannot 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.

PG&E Corporation's and the Utility's financial statements reflect various estimates and assumptions, including assumptions about the value of assets held in trust, that could prove to be different.

As described in Note 1 of the Notes to the Consolidated Financial Statements, PG&E Corporation's and the Utility's financial statements reflect management's estimates and assumptions that affect the reported amounts of revenues, expenses, assets and liabilities, and the disclosure of contingencies. In particular, the financial statements reflect the values of the assets held in trust to satisfy the Utility's obligations to decommission its nuclear generation facilities and under pension and other post-retirement benefit plans. The value of these assets is subject to market fluctuations. Also, certain assets held in these trusts do not have readily determinable market values. Changes in the estimates and assumptions inherent in the value of these assets could affect the value of the trusts. If the value of the assets held by the trusts declines by a material amount, the Utility's funding obligation to the trusts would materially increase.

The outcome of pending and future litigation and legal proceedings, the application of and changes in accounting standards or guidance, tax laws, labor laws, rates or policies, may also 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 flow 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 flow.

CONSOLIDATED BALANCE SHEETS

PG&E Corporation

	Balance at December 31,	
(in millions)	2007	2006
ASSETS		
Current Assets		
Cash and cash equivalents	$ 345	$ 456
Restricted cash	1,297	1,415
Accounts receivable:		
Customers (net of allowance for doubtful accounts of $58 million in 2007 and $50 million in 2006)	2,349	2,343
Regulatory balancing accounts	771	607
Inventories:		
Gas stored underground and fuel oil	205	181
Materials and supplies	166	149
Income taxes receivable	61	–
Prepaid expenses and other	317	716
Total current assets	5,511	5,867
Property, Plant, and Equipment		
Electric	25,599	24,036
Gas	9,620	9,115
Construction work in progress	1,348	1,047
Other	17	16
Total property, plant, and equipment	36,584	34,214
Accumulated depreciation	(12,928)	(12,429)
Net property, plant, and equipment	23,656	21,785
Other Noncurrent Assets		
Regulatory assets	4,459	4,902
Nuclear decommissioning funds	1,979	1,876
Other	1,043	373
Total other noncurrent assets	7,481	7,151
TOTAL ASSETS	$ 36,648	$ 34,803

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

PG&E Corporation

(in millions, except share amounts)	Balance at December 31, 2007	2006
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-term borrowings	$ 519	$ 759
Long-term debt, classified as current	–	281
Rate reduction bonds, classified as current	–	290
Energy recovery bonds, classified as current	354	340
Accounts payable:		
Trade creditors	1,067	1,075
Disputed claims and customer refunds	1,629	1,709
Regulatory balancing accounts	673	1,030
Other	394	420
Interest payable	697	583
Income taxes payable	–	102
Deferred income taxes	–	148
Other	1,390	1,513
Total current liabilities	6,723	8,250
Noncurrent Liabilities		
Long-term debt	8,171	6,697
Energy recovery bonds	1,582	1,936
Regulatory liabilities	4,448	3,392
Asset retirement obligations	1,579	1,466
Income taxes payable	234	–
Deferred income taxes	3,053	2,840
Deferred tax credits	99	106
Other	1,954	2,053
Total noncurrent liabilities	21,120	18,490
Commitments and Contingencies (Notes 2, 4, 5, 6, 7, 8, 9, 11, 13, 15, and 17)		
Preferred Stock of Subsidiaries	252	252
Preferred Stock		
Preferred stock, no par value, authorized 80,000,000 shares, $100 par value, authorized 5,000,000 shares, none issued	–	–
Common Shareholders' Equity		
Common stock, no par value, authorized 800,000,000 shares, issued 378,385,151 common and 1,261,125 restricted shares in 2007 and issued 372,803,521 common and 1,377,538 restricted shares in 2006	6,110	5,877
Common stock held by subsidiary, at cost, 24,665,500 shares	(718)	(718)
Reinvested earnings	3,151	2,671
Accumulated other comprehensive income (loss)	10	(19)
Total common shareholders' equity	8,553	7,811
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 36,648	$ 34,803

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

PG&E Corporation

(in millions)	Year ended December 31, 2007	2006	2005
Cash Flows From Operating Activities			
Net income	$ 1,006	$ 991	$ 917
Gain on disposal of NEGT (net of income tax benefit of $13 million in 2005)	–	–	(13)
Net income from continuing operations	1,006	991	904
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, amortization, decommissioning, and allowance for equity funds used during construction	1,895	1,756	1,698
Tax benefit from employee stock plans	–	–	50
Gain on sale of assets	(1)	(11)	–
Deferred income taxes and tax credits, net	55	(285)	(659)
Other changes in noncurrent assets and liabilities	192	151	33
Net effect of changes in operating assets and liabilities:			
Accounts receivable	(6)	130	(245)
Inventories	(41)	32	(60)
Accounts payable	(178)	17	257
Accrued taxes/income taxes receivable	56	124	(207)
Regulatory balancing accounts, net	(567)	329	254
Other current assets	172	(273)	29
Other current liabilities	8	(233)	273
Other	(45)	(14)	82
Net cash provided by operating activities	2,546	2,714	2,409
Cash Flows From Investing Activities			
Capital expenditures	(2,769)	(2,402)	(1,804)
Net proceeds from sale of assets	21	17	39
Decrease in restricted cash	185	115	434
Proceeds from nuclear decommissioning trust sales	830	1,087	2,918
Purchases of nuclear decommissioning trust investments	(933)	(1,244)	(3,008)
Other	–	–	23
Net cash used in investing activities	(2,666)	(2,427)	(1,398)
Cash Flows From Financing Activities			
Borrowings under accounts receivable facility and working capital facility	850	350	260
Repayments under accounts receivable facility and working capital facility	(900)	(310)	(300)
Net issuance (repayments) of commercial paper, net of discount of $1 million in 2007 and $2 million in 2006	(209)	458	–
Proceeds from issuance of long-term debt, net of discount and issuance costs of $16 million in 2007 and $3 million in 2005	1,184	–	451
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)
Rate reduction bonds matured	(290)	(290)	(290)
Energy recovery bonds matured	(340)	(316)	(140)
Preferred stock with mandatory redemption provisions redeemed	–	–	(122)
Preferred stock without mandatory redemption provisions redeemed	–	–	(37)
Common stock issued	175	131	243
Common stock repurchased	–	(114)	(2,188)
Common stock dividends paid	(496)	(456)	(334)
Other	35	3	32
Net cash provided by (used in) financing activities	9	(544)	(1,270)
Net change in cash and cash equivalents	(111)	(257)	(259)
Cash and cash equivalents at January 1	456	713	972
Cash and cash equivalents at December 31	$ 345	$ 456	$ 713
Supplemental disclosures of cash flow information			
Cash paid for:			
Interest (net of amounts capitalized)	$ 514	$ 503	$ 403
Income taxes paid, net	537	736	1,392
Supplemental disclosures of noncash investing and financing activities			
Common stock dividends declared but not yet paid	$ 129	$ 117	$ 115
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 Other Comprehensive Income (Loss)	Total Common Shareholders' Equity	Comprehensive Income
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	
Accelerated share repurchase 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**	
Net income	–	–	–	–	1,006	–	1,006	$1,006
Employee benefit plan adjustment in accordance with SFAS No. 158 (net of income tax expense of $17 million)	–	–	–	–	–	29	29	29
Comprehensive income								$1,035
Common stock issued, net	5,465,217	175	–	–	–	–	175	
Stock-based compensation amortization	–	31	–	–	–	–	31	
Common stock dividends declared and paid	–	–	–	–	(379)	–	(379)	
Common stock dividends declared but not yet paid	–	–	–	–	(129)	–	(129)	
Tax benefit from employee stock plans	–	27	–	–	–	–	27	
Adoption of FIN 48	–	–	–	–	(18)	–	(18)	
Balance at December 31, 2007	379,646,276	$6,110	$(718)	$ –	$ 3,151	$ 10	$ 8,553	

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF INCOME

Pacific Gas and Electric Company

(in millions)	Year ended December 31, 2007	2006	2005
Operating Revenues			
Electric	$ 9,481	$ 8,752	$ 7,927
Natural gas	3,757	3,787	3,777
Total operating revenues	13,238	12,539	11,704
Operating Expenses			
Cost of electricity	3,437	2,922	2,410
Cost of natural gas	2,035	2,097	2,191
Operating and maintenance	3,872	3,697	3,399
Depreciation, amortization, and decommissioning	1,769	1,708	1,734
Total operating expenses	11,113	10,424	9,734
Operating Income	2,125	2,115	1,970
Interest income	150	175	76
Interest expense	(732)	(710)	(554)
Other income, net	52	7	16
Income Before Income Taxes	1,595	1,587	1,508
Income tax provision	571	602	574
Net Income	1,024	985	934
Preferred stock dividend requirement	14	14	16
Income Available for Common Stock	$ 1,010	$ 971	$ 918

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

Pacific Gas and Electric Company

(in millions)	Balance at December 31, 2007	2006
ASSETS		
Current Assets		
Cash and cash equivalents	$ 141	$ 70
Restricted cash	1,297	1,415
Accounts receivable:		
Customers (net of allowance for doubtful accounts of $58 million in 2007 and $50 million in 2006)	2,349	2,343
Related parties	6	6
Regulatory balancing accounts	771	607
Inventories:		
Gas stored underground and fuel oil	205	181
Materials and supplies	166	149
Income taxes receivable	15	20
Prepaid expenses and other	314	714
Total current assets	5,264	5,505
Property, Plant, and Equipment		
Electric	25,599	24,036
Gas	9,620	9,115
Construction work in progress	1,348	1,047
Total property, plant, and equipment	36,567	34,198
Accumulated depreciation	(12,913)	(12,415)
Net property, plant, and equipment	23,654	21,783
Other Noncurrent Assets		
Regulatory assets	4,459	4,902
Nuclear decommissioning funds	1,979	1,876
Related parties receivable	23	25
Other	947	280
Total other noncurrent assets	7,408	7,083
TOTAL ASSETS	$ 36,326	$ 34,371

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, 2007	2006
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-term borrowings	$ 519	$ 759
Long-term debt, classified as current	–	1
Rate reduction bonds, classified as current	–	290
Energy recovery bonds, classified as current	354	340
Accounts payable:		
Trade creditors	1,067	1,075
Disputed claims and customer refunds	1,629	1,709
Related parties	28	40
Regulatory balancing accounts	673	1,030
Other	370	402
Interest payable	697	570
Deferred income taxes	4	118
Other	1,216	1,346
Total current liabilities	6,557	7,680
Noncurrent Liabilities		
Long-term debt	7,891	6,697
Energy recovery bonds	1,582	1,936
Regulatory liabilities	4,448	3,392
Asset retirement obligations	1,579	1,466
Income taxes payable	103	–
Deferred income taxes	3,104	2,972
Deferred tax credits	99	106
Other	1,838	1,922
Total noncurrent liabilities	20,644	18,491
Commitments and Contingencies (Notes 2, 4, 5, 6, 7, 8, 9, 11, 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 282,916,485 shares in 2007 and issued 279,624,823 shares in 2006	1,415	1,398
Common stock held by subsidiary, at cost, 19,481,213 shares	(475)	(475)
Additional paid-in capital	2,220	1,822
Reinvested earnings	5,694	5,213
Accumulated other comprehensive income (loss)	13	(16)
Total shareholders' equity	9,125	8,200
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 36,326	$ 34,371

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Pacific Gas and Electric Company

	Year ended December 31,		
(in millions)	2007	2006	2005
Cash Flows From Operating Activities			
Net income	$ 1,024	$ 985	$ 934
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, amortization, decommissioning, and allowance for equity funds used during construction	1,892	1,755	1,697
Gain on sale of assets	(1)	(11)	–
Deferred income taxes and tax credits, net	43	(287)	(636)
Other changes in noncurrent assets and liabilities	188	116	21
Net effect of changes in operating assets and liabilities:			
Accounts receivable	(6)	128	(245)
Inventories	(41)	34	(60)
Accounts payable	(196)	21	257
Accrued taxes/income taxes receivable	56	28	(150)
Regulatory balancing accounts, net	(567)	329	254
Other current assets	170	(273)	2
Other current liabilities	24	(235)	273
Other	(45)	(13)	19
Net cash provided by operating activities	2,541	2,577	2,366
Cash Flows From Investing Activities			
Capital expenditures	(2,768)	(2,402)	(1,803)
Net proceeds from sale of assets	21	17	39
Decrease in restricted cash	185	115	434
Proceeds from nuclear decommissioning trust sales	830	1,087	2,918
Purchases of nuclear decommissioning trust investments	(933)	(1,244)	(3,008)
Other	–	1	61
Net cash used in investing activities	(2,665)	(2,426)	(1,359)
Cash Flows From Financing Activities			
Borrowings under accounts receivable facility and working capital facility	850	350	260
Repayments under accounts receivable facility and working capital facility	(900)	(310)	(300)
Net issuance (repayments) of commercial paper, net of discount of $1 million in 2007 and $2 million in 2006	(209)	458	–
Proceeds from issuance of long-term debt, net of discount and issuance costs of $16 million in 2007 and $3 million in 2005	1,184	–	451
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)
Rate reduction bonds matured	(290)	(290)	(290)
Energy recovery bonds matured	(340)	(316)	(140)
Preferred stock dividends paid	(14)	(14)	(16)
Common stock dividends paid	(509)	(460)	(445)
Preferred stock with mandatory redemption provisions redeemed	–	–	(122)
Preferred stock without mandatory redemption provisions redeemed	–	–	(37)
Equity infusion from PG&E Corporation	400	–	–
Common stock repurchased	–	–	(1,910)
Other	23	38	65
Net cash provided by (used in) financing activities	195	(544)	(1,327)
Net change in cash and cash equivalents	71	(393)	(320)
Cash and cash equivalents at January 1	70	463	783
Cash and cash equivalents at December 31	$ 141	$ 70	$ 463
Supplemental disclosures of cash flow information			
Cash paid for:			
Interest (net of amounts capitalized)	$ 474	$ 476	$ 390
Income taxes paid, net	594	897	1,397
Supplemental disclosures of noncash investing and financing activities			
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 Share-holders' Equity	Compre-hensive Income
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**	
Net income	–	–	–	–	1,024	–	1,024	$1,024
Employee benefit plan adjustment in accordance with SFAS No. 158 (net of income tax expense of $17 million)	–	–	–	–	–	29	29	29
Comprehensive income								$1,053
Equity infusion	–	17	383	–	–	–	400	
Tax benefit from employee stock plans	–	–	15	–	–	–	15	
Common stock dividend	–	–	–	–	(509)	–	(509)	
Preferred stock dividend	–	–	–	–	(14)	–	(14)	
Adoption of FIN 48	–	–	–	–	(20)	–	(20)	
Balance at December 31, 2007	$258	$1,415	$2,220	$(475)	$ 5,694	$ 13	$ 9,125	

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 ("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 ("CPUC") and the Federal Energy Regulatory Commission ("FERC").

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 ("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, the remaining disputed claims made by electricity suppliers in the Utility's proceeding under Chapter 11 of the U.S. Bankruptcy Code ("Disputed Claims") and customer refunds, asset retirement obligations ("ARO"), allowance for doubtful accounts receivable, provisions for losses that are deemed probable from environmental remediation liabilities, pension and other employee benefit plan liabilities, severance costs, fair value accounting under Statement of Financial Accounting Standards ("SFAS") No. 133, "Accounting for Derivative Instruments and Hedging Activities" ("SFAS No. 133"), income tax-related assets and liabilities, accruals for legal matters, 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. A change in management's estimates or assumptions could have a material impact on PG&E Corporation's and the Utility's financial condition and results of operations during the period in which such change occurred. 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.

PG&E Corporation and the Utility each had three account balances that were each greater than 10% of PG&E Corporation's and the Utility's total cash and cash equivalents balance at December 31, 2007.

RESTRICTED CASH

Restricted cash consists primarily of the Utility's cash held in escrow pending the resolution of the remaining Disputed Claims (see further discussion in Note 15). The Utility also provides deposits 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.

INVENTORIES

Inventories are carried at average cost and are valued at the lower of average cost or market. Inventories 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. Gas stored underground represents purchases that are injected into inventory and then expensed at average cost when withdrawn and 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 ("AFUDC").

AFUDC

Allowance for funds used during construction ("AFUDC") represents a method used to compensate the Utility for the estimated cost of debt and equity used to finance regulated plant additions and is 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. PG&E Corporation and the Utility recorded AFUDC of approximately $64 million and $32 million related to equity and debt, respectively, during 2007; $47 million and $20 million related to equity and debt, respectively, during 2006; and $37 million and $14 million related to equity and debt, respectively, during 2005.

Depreciation

The Utility's composite depreciation rate was 3.28% in 2007, 3.09% in 2006, and 3.28% in 2005.

(in millions)	Gross Plant as of December 31, 2007	Estimated Useful Lives
Electricity generating facilities	$ 2,198	4 to 37 years
Electricity distribution facilities	16,116	16 to 58 years
Electricity transmission	4,675	40 to 70 years
Natural gas distribution facilities	5,218	24 to 52 years
Natural gas transportation	3,141	25 to 45 years
Natural gas storage	47	25 to 48 years
Other	3,824	5 to 43 years
Total	$35,219	

The useful lives of the Utility's property, plant, and equipment are authorized by the CPUC and the FERC and depreciation expense is 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.

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 ("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" ("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 $533 million at December 31, 2007 and $237 million at December 31, 2006, net of accumulated amortization of approximately $207 million at December 31, 2007 and $197 million at December 31, 2006. The increase in capitalized software costs from 2006 to 2007 was primarily due to expenses related to software development for the SmartMeter™ program, as well as information system upgrades of several processes and tools used to design, estimate, and schedule work. PG&E Corporation and the Utility amortize 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 currently 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.

INTANGIBLE ASSETS

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 $97 million at December 31, 2007 and $73 million at December 31, 2006. The accumulated amortization was approximately $32 million at December 31, 2007 and $28 million at December 31, 2006.

The Utility's amortization expense related to intangible assets was approximately $3 million in 2007, 2006, and 2005. The estimated annual amortization expense based on the December 31, 2007 intangible asset balance for the Utility's intangible assets for 2008 through 2012 is approximately $3 million each year. Intangible assets are recorded to Other Noncurrent Assets in the Consolidated Balance Sheets.

CONSOLIDATION OF VARIABLE INTEREST ENTITIES

The Financial Accounting Standards Board ("FASB") Interpretation No. 46 (revised December 2003), "Consolidation of Variable Interest Entities" ("FIN 46R"), provides that an entity is a variable interest entity ("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 the majority of the risk of loss from a VIE's activities must consolidate the VIE. However, if no holder has the majority of the risk of loss, then a holder entitled to receive a majority of the entity's residual returns would consolidate the entity.

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. In 2007, the Utility entered into a 25-year agreement to purchase as-available electric generation output from a new approximately 554-megawatt ("MW") solar trough facility in which the Utility has a significant variable interest.

Activities of this facility consist of renewable energy production from a single facility for sale to third parties. The Utility is not considered the primary beneficiary for this VIE, as it will not absorb the majority of the entity's expected losses or residual returns. Accordingly, the Utility will not consolidate this VIE in its consolidated financial statements. This project is expected to become operational in 2011 and no payments for energy have been made to this facility as of December 31, 2007. Future payments to this facility are expected to be recoverable through customer rates.

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" ("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. No significant impairments were recorded in 2007, 2006, and 2005.

ASSET RETIREMENT OBLIGATIONS

PG&E Corporation and the Utility account for ARO in accordance with SFAS No. 143, "Accounting for Asset Retirement Obligations" ("SFAS No. 143") and FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations – an Interpretation of FASB Statement No. 143" ("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 identified its nuclear generation and certain fossil fuel generation facilities as having ARO under SFAS No. 143. In accordance with FIN 47, the Utility has identified ARO 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 has recorded ARO 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, 2005	$1,587
Revision in estimated cash flows	(204)
Accretion	98
Liabilities settled	(15)
ARO liability at December 31, 2006	1,466
Revision in estimated cash flows	48
Accretion	95
Liabilities settled	(30)
ARO liability at December 31, 2007	**$1,579**

The Utility has identified additional ARO 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 Utility 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 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, 2007 and 2006.
- The fair values of the Utility's fixed rate senior notes, fixed rate pollution control bond loan agreements, and PG&E Energy Recovery Funding LLC's ("PERF") energy recovery bonds ("ERBs") were based on quoted market prices obtained from the Bloomberg financial information system at December 31, 2007.
- The estimated fair value of PG&E Corporation's 9.50% Convertible Subordinated debt was determined by considering the prices of securities displayed as of the close of business on December 31, 2007 by a proprietary bond trading system which tracks and marks a broad universe of convertible securities including the securities being assessed.

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,			
	2007		2006	
(in millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Debt (Note 4):				
PG&E Corporation	$ 280	$ 849	$ 280	$ 937
Utility	6,823	6,701	5,629	5,616
Rate reduction bonds (Note 5)[1]	–	–	290	292
Energy recovery bonds (Note 6)	1,936	1,928	2,276	2,239

(1) Rate Reduction Bonds matured on December 26, 2007. (See "Note 5: Rate Reduction Bonds" below.)

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. Unamortized loss on debt extinguishments, net of gain, was approximately $269 million and $295 million at December 31, 2007 and 2006, respectively. The Utility's amortization expense related to this loss was approximately $26 million in 2007, $27 million in 2006, and $32 million in 2005. Deferred gains and losses on debt extinguishments are recorded to Other Noncurrent Assets – Regulatory Assets in the Consolidated Balance Sheets.

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 after-tax changes in each component of accumulated other comprehensive income (loss):

(in millions)	Hedging Transactions in Accordance with SFAS No. 133	Minimum Pension Liability Adjustment	Adoption of SFAS No. 158	Employee Benefit Plan Adjustment in Accordance with SFAS No. 158	Other	Accumulated Other Comprehensive Income (Loss)
Balance at December 31, 2004	$(1)	$(4)	$ –	$ –	$ 1	$ (4)
Period change in:						
Minimum pension liability adjustment (net of income tax benefit of $3 million)	–	(4)	–	–	–	(4)
Other	1	–	–	–	(1)	–
Balance at December 31, 2005	–	(8)	–	–	–	(8)
Period change in:						
Adoption of SFAS No. 158 (net of income tax benefit of $8 million)	–	8	(19)	–	–	(11)
Balance at December 31, 2006	–	–	(19)	–	–	(19)
Period change in pension benefits and other benefits:						
Unrecognized prior service cost (net of income tax expense of $18 million)	–	–	–	26	–	26
Unrecognized net gain (net of income tax expense of $195 million)	–	–	–	289	–	289
Unrecognized net transition obligation (net of income tax expense of $11 million)	–	–	–	16	–	16
Transfer to regulatory account (net of income tax benefit of $207 million)[1]	–	–	–	(302)	–	(302)
Balance at December 31, 2007	$–	$–	$(19)	$ 29	$–	$ 10

(1) The Utility recorded approximately $109 million in 2007 and $574 million in 2006, pre-tax, as a reduction to the existing pension regulatory liability in accordance with the provisions of SFAS No. 71. The Utility recorded approximately $44 million, pre-tax, as an addition to the existing pension regulatory liability in accordance with SFAS No. 71.

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 ("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 ("EPS") in accordance with SFAS No. 128, "Earnings Per Share" ("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.

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 a combined state income tax return in California. 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.

SHARE-BASED PAYMENT

On January 1, 2006, PG&E Corporation and the Utility adopted the provisions of SFAS No. 123R, "Share-Based Payment" ("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 Opinion No. 25, "Accounting for Stock Issued to Employees" ("Opinion 25") as permitted by SFAS No. 123, "Accounting for Stock-Based Compensation" ("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.

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.

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 year ended December 31, 2005:

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

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
Net earnings:	
As reported	$918
Deduct: Incremental stock-based employee compensation expense determined under the fair value based method for all awards, net of related tax effects	(7)
Pro forma	$911

NUCLEAR DECOMMISSIONING TRUSTS

The Utility accounts for its investments held in the Nuclear Decommissioning Trusts in accordance with SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities" ("SFAS No. 115"), as well as FASB Staff Position Nos. 115-1 and 124-1, "The Meaning of Other-Than-Temporary Impairment and Its Application to Certain Investments" ("SFAS Nos. 115-1 and 124-1"). Under SFAS No. 115, the Utility records realized gains and losses as additions and reductions to trust asset balances. In accordance with SFAS Nos. 115-1 and 124-1, the Utility recognizes an impairment of an investment if the fair value of that investment is less than its cost and if the impairment is concluded to be other-than-temporary. (See Note 13 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. 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 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. Derivative instruments are recorded in 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 regulatory accounts. Derivative instruments are presented in other current and noncurrent assets or other current and noncurrent liabilities unless they meet certain exemptions as discussed below.

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 in 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 in PG&E Corporation's and the Utility's Consolidated Statements of Cash Flows.

The fair value of derivative instruments is estimated using the mid-point 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, 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 in the Utility's Consolidated Balance Sheets at fair value. They are recorded and recognized in income under the accrual method of 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 in the Utility's Consolidated Balance Sheets at fair value. Expenses are recognized as incurred.

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

ADOPTION OF NEW ACCOUNTING PRONOUNCEMENTS

Accounting for Uncertainty in Income Taxes

On January 1, 2007, PG&E Corporation and the Utility adopted the provisions of FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" ("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 based on the merits of the position. If this threshold is met, the second step is to measure the tax position in PG&E Corporation's and the Utility's Consolidated Balance Sheets by using the largest amount of benefit that is greater than 50% likely of being realized upon ultimate settlement. The difference between a tax position taken or expected to be taken in a tax return and the benefit recognized and measured pursuant to FIN 48 represents an unrecognized tax benefit. An unrecognized tax benefit is a liability that represents a potential future obligation to the taxing authority.

The effects of adopting FIN 48 were as follows:

(in millions)	PG&E Corporation	Utility
At January 1, 2007		
Cumulative effect of adoption – decrease to Beginning Reinvested Earnings	$18	$20

A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

(in millions)	PG&E Corporation	Utility
Balance at January 1, 2007	$212	$90
Additions for tax position of prior years	15	4
Reductions for tax position of prior years	(18)	–
Balance at December 31, 2007	**$209**	**$94**

The component of unrecognized tax benefits that, if recognized, would affect the effective tax rate at December 31, 2007 for PG&E Corporation and the Utility is $110 million and $63 million, respectively.

Interest expense was calculated and included in the potential liability for uncertain tax positions for the 12 months ended December 31, 2007. Interest expense was classified as income tax expense in the Consolidated Statements of Income as follows:

(in millions)	PG&E Corporation	Utility
For the 12 months ended December 31, 2007		
Increase in interest expense accrued on unrecognized tax benefits	$7	$2

PG&E Corporation and the Utility believe that it is reasonably possible that the total amount of unrecognized tax benefits could decrease by up to $10 million in the next 12 months as a result of a potential settlement of the 2001–2002 Internal Revenue Service ("IRS") audit.

For a description of tax years that remain subject to examination, see discussion in Note 11 of the Notes to the Consolidated Financial Statements.

ACCOUNTING PRONOUNCEMENTS ISSUED BUT NOT YET ADOPTED

Fair Value Measurements

On January 1, 2008, PG&E Corporation and the Utility adopted the provisions of SFAS No. 157, "Fair Value Measurements," ("SFAS No. 157"), which defines fair value measurements and implements a hierarchical disclosure.

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," or the "exit price." Accordingly, an entity must now determine the fair value of an asset or liability based on the assumptions that market participants would use in pricing the asset or liability, not those of the reporting entity itself. The identification of market participant assumptions provides a basis for determining what inputs are to be used for pricing each asset or liability. Additionally, SFAS No. 157 establishes a fair value hierarchy which gives precedence to fair value measurements calculated using observable inputs to those using unobservable inputs. Accordingly, the following levels were established for each input:

- **Level 1** — "Inputs that are quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date."
- **Level 2** — "Inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly or indirectly."
- **Level 3** — "Unobservable inputs for the asset or liability." These are inputs for which there is no market data available, or observable inputs that are adjusted using Level 3 assumptions.

SFAS No. 157 requires entities to disclose financial fair-valued instruments according to the above hierarchy in each reporting period after implementation. The standard deferred the disclosure of the hierarchy for certain non-financial instruments to fiscal years beginning after November 15, 2008.

SFAS No. 157 should be applied prospectively except if certain criteria are met. Congestion Revenue Rights ("CRRs") held by the Utility meet the criteria and will be adjusted upon adoption to comply with SFAS No. 157 requirements. CRRs allow market participants, including load serving entities, to hedge the financial risk of California Independent System Operator ("CAISO") imposed congestion charges in the Market Redesign and Technology Upgrade ("MRTU") day-ahead market. PG&E Corporation and the Utility are still evaluating the impact of the adjustment to price risk management assets and regulatory liabilities on their Consolidated Balance Sheets. The costs associated with procurement of CRRs are currently being recovered in rates or are probable of recovery in future rates; therefore, the adoption of SFAS No. 157 will not have an impact on earnings.

Fair Value Option

In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities" ("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 do not expect the adoption of SFAS No. 159 to materially impact the financial statements.

Amendment of FASB Interpretation No. 39

In April 2007, the FASB issued FASB Staff Position on Interpretation 39, "Amendment of FASB Interpretation No. 39" ("FIN 39-1"). Under FIN 39-1, a reporting entity is permitted to offset the fair value amounts recognized for cash collateral paid or cash collateral received against the fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting arrangement. FIN 39-1 is effective for fiscal years beginning after November 15, 2007. PG&E Corporation and the Utility are currently evaluating the impact of FIN 39-1.

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)	2007	2006
Energy recovery bond regulatory asset	$1,833	$2,170
Utility retained generation regulatory assets	947	1,018
Regulatory assets for deferred income tax	732	599
Environmental compliance costs	328	303
Unamortized loss, net of gain, on reacquired debt	269	295
Regulatory assets associated with plan of reorganization	122	147
Contract termination costs	96	120
Scheduling coordinator costs	90	111
Other	42	139
Total regulatory assets	$4,459	$4,902

The energy recovery bond ("ERB") regulatory asset represents the 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 proceeding under Chapter 11 of the U.S. Bankruptcy Code (the "Chapter 11 Settlement Agreement"). During 2007, the Utility recorded amortization of the ERB regulatory asset of approximately $337 million. The Utility 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 in 2004 for regulatory assets related to the recovery of previously incurred costs associated with retained generation facilities. The individual components of these regulatory assets are amortized over their respective lives, with a weighted average life of approximately 16 years. During 2007, the Utility recorded amortization of the Utility's retained generation regulatory assets of approximately $71 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 taxes 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 actual 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 periods ranging from 1 to 19 years.

Regulatory assets associated with the Utility's Chapter 11 Settlement Agreement include costs incurred in financing the Utility's reorganization under Chapter 11 and costs to oversee the environmental enhancement projects 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.

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 ("SC") costs represents costs that the Utility incurred beginning in 1998 in its capacity as an SC for its then existing wholesale transmission customers. The Utility expects to fully recover the SC costs by 2009.

Finally, as of December 31, 2007, "Other" is primarily related to timing differences between the recognition of ARO in accordance with GAAP and the amounts recognized for ratemaking purposes. At 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.

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's 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, 2007, the Utility had current regulatory assets of approximately $131 million, consisting primarily of price risk management regulatory assets with terms of less than one year. Price risk management regulatory assets consist of contracts to procure electricity and natural gas designed to reduce commodity price risks that are accounted for as derivatives under SFAS No. 133. The costs and proceeds of these derivative instruments are recovered or refunded through regulated rates. At December 31, 2006, the amount of current regulatory assets was approximately $434 million, consisting primarily of the current portion of the rate reduction bond ("RRB") regulatory asset and price risk management regulatory assets. The RRB regulatory asset represents electric industry restructuring costs, which the Utility fully recovered in 2007. Current regulatory assets are included in Prepaid Expenses and Other in the Consolidated Balance Sheets.

REGULATORY LIABILITIES

Long-term regulatory liabilities are comprised of the following:

	Balance at December 31,	
(in millions)	2007	2006
Cost of removal obligation	$2,568	$2,340
Asset retirement costs	573	608
Public purpose programs	264	169
California Solar Initiative	159	–
Price risk management	124	37
Employee benefit plans	578	23
Other	182	215
Total regulatory liabilities	$4,448	$3,392

Cost of removal liabilities represent 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 ARO in accordance with GAAP and the amounts recognized for ratemaking purposes.

Public purpose program liabilities represent revenues designated for public purpose program costs that are expected to be incurred in the future.

California Solar Initiative liabilities represent revenues designated for public purpose program costs that are expected to be incurred in the future. These revenues will be used by the Utility to promote the use of solar energy in residential homes and commercial, industrial, and agricultural properties.

Price risk management liabilities consist of contracts to procure electricity and natural gas with terms in excess of one year designed to reduce commodity price risks that are accounted for as derivative instruments under SFAS No. 133. Changes in the fair value of derivative instruments are deferred and recorded in regulatory accounts because they are recovered or refunded through regulated rates.

Employee benefit plan expenses represent the cumulative differences between amounts recognized in accordance with GAAP and amounts recognized for ratemaking purposes, which also includes amounts that otherwise would be recorded to accumulated other comprehensive income in accordance with SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans." These balances will be charged against expense to the extent that future expenses exceed amounts recoverable for regulatory purposes.

Finally, as of December 31, 2007, "Other" regulatory liabilities are primarily related to amounts received from insurance companies to pay for hazardous substance remediation costs and future customer benefits associated with the Gateway Generating Station ("Gateway"). The liability for hazardous substance insurance recoveries is refunded to customers as a reduction to rates until they are fully reimbursed for total covered hazardous substance costs that they have paid to date. Gateway was acquired as part of a settlement with Mirant Corporation and the associated liability will be amortized over 30 years beginning in March 2009.

Current Regulatory Liabilities

As of December 31, 2007, the Utility had current regulatory liabilities of approximately $280 million, primarily consisting of the current portion of electric transmission wheeling revenue refunds and amounts that the Utility expects to refund to customers for over-collected electric transmission rates. At December 31, 2006, the Utility had current regulatory liabilities of $309 million, primarily comprised of electric transmission wheeling revenue refunds and the RRB regulatory liability. The RRB regulatory liability represents over-collections associated with the RRB financing that the Utility will return to customers in the future. Current regulatory liabilities are included in Current Liabilities – Other in the Consolidated Balance Sheets.

REGULATORY BALANCING ACCOUNTS

The Utility uses regulatory balancing accounts as a mechanism 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 eliminates the earnings impact from any 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 Other Noncurrent Assets – Regulatory Assets and Noncurrent Liabilities – Regulatory 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)	2007	2006
Electricity revenue and cost balancing accounts	$678	$501
Natural gas revenue and cost balancing accounts	93	106
Total	$771	$607

Regulatory Balancing Account Liabilities

	Balance at December 31,	
(in millions)	2007	2006
Electricity revenue and cost balancing accounts	$618	$ 951
Natural gas revenue and cost balancing accounts	55	79
Total	$673	$1,030

During 2007, the under-collection in the Utility's electricity revenue and cost balancing account assets increased from 2006 mainly due to higher procurement costs associated with replacement power, as a result of lower hydroelectric production. The under-collection was further increased due to CPUC authorized rate reductions intended to reduce over-collections in the electric revenue and cost balancing account liabilities from 2006.

NOTE 4: DEBT

LONG-TERM DEBT

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

	December 31,	
(in millions)	2007	2006
PG&E Corporation		
Convertible subordinated notes, 9.50%, due 2010	$ 280	$ 280
Less: current portion	–	(280)
	280	–
Utility		
Senior notes:		
3.60% to 6.05% bonds, due 2009–2037	6,300	5,100
Unamortized discount	(22)	(16)
Total senior notes	6,278	5,084
Pollution control bond loan agreements, variable rates(1), due 2026(2)	614	614
Pollution control bond loan agreement, 5.35%, due 2016	200	200
Pollution control bond loan agreements, 4.75%, due 2023	345	345
Pollution control bond loan agreements, variable rates(3), due 2016–2026	454	454
Other	–	1
Less: current portion	–	(1)
Long-term debt, net of current portion	7,891	6,697
Total consolidated long-term debt, net of current portion	**$8,171**	**$6,697**

(1) At December 31, 2007, interest rates on these loans ranged from 3.45% to 3.73%.

(2) These bonds are supported by $620 million of letters of credit which expire on February 24, 2012. Although the stated maturity date is 2026, the bonds will remain outstanding only if the Utility extends or replaces the letters of credit.

(3) At December 31, 2007, interest rates on these loans ranged from 3.75% to 5.75%.

PG&E CORPORATION

Convertible Subordinated Notes

At December 31, 2007, PG&E Corporation had outstanding approximately $280 million of 9.50% Convertible Subordinated Notes that are scheduled to mature on June 30, 2010. Interest is payable semi-annually in arrears on June 30 and December 31. These Convertible Subordinated Notes may be converted (at the option of the holder) at any time prior to maturity into 18,558,059 shares of PG&E Corporation common stock, at a conversion price of $15.09 per share. The conversion price is subject to adjustment for significant changes in the number of outstanding shares of PG&E Corporation's common stock. 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. During 2007, PG&E Corporation paid approximately $26 million of "pass-through dividends" to the holders of Convertible Subordinated Notes. On January 15, 2008, PG&E Corporation paid approximately $7 million of "pass-through dividends." Since no holders of the Convertible Subordinated Notes exercised the one-time right to require PG&E Corporation to repurchase the Convertible Subordinated Notes on June 30, 2007, PG&E Corporation reclassified the Convertible Subordinated Notes as a noncurrent liability (in Noncurrent Liabilities – Long-Term Debt) in the Consolidated Balance Sheets effective as of that date.

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. Dividend participation rights are recognized as operating cash flows in PG&E Corporation's Consolidated Statements of Cash Flows. Changes in the fair value are recognized in PG&E Corporation's Consolidated Statements of Income as a non-operating expense or income (in Other Income, Net). At December 31, 2007 and December 31, 2006, the total estimated fair value of the dividend participation rights component, on a pre-tax basis, was approximately $62 million and $79 million, respectively, of which $25 million and $23 million, respectively, was classified as a current liability (in Current Liabilities – Other) and $37 million and $56 million, respectively, was classified as a noncurrent liability (in Noncurrent Liabilities – Other) in the accompanying Consolidated Balance Sheets.

UTILITY

Senior Notes

In March 2007, the Utility issued $700 million principal amount of 5.80% Senior Notes due March 1, 2037. The Utility received proceeds of $690 million from the offering, net of a $4 million discount and $6 million in issuance costs. In December 2007, the Utility issued $500 million principal amount of 5.625% Senior Notes due November 30, 2017. The Utility received proceeds of $494 million from the offering, net of a $3 million discount and $3 million in issuance costs. The proceeds from the sale of the Senior Notes were used for capital expenditures and working capital purposes.

The Utility's Senior Notes are unsecured and rank equally with the Utility's other senior unsecured and unsubordinated debt. Under the indenture for the Senior Notes, the Utility has agreed that it will not incur secured debt or engage in sale leaseback transactions (except for (1) debt secured by specified liens, and (2) aggregate other secured debt and sales and leaseback transactions not exceeding 10% of the Utility's net tangible assets, as defined in the indenture) unless the Utility provides that the Senior Notes will be equally and ratably secured.

Pollution Control Bonds

The California Pollution Control Financing Authority and the California Infrastructure and Economic Development Bank issued various series of tax-exempt pollution control bonds for the benefit of the Utility. At December 31, 2007, 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 ("Geysers Project"), or at the Utility's Diablo Canyon Power Plant ("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 ("Code").

On February 3, 2006, Geysers Power Company LLC filed a petition for relief under Chapter 11 of the Bankruptcy Code with the United States Bankruptcy Court for the Northern District of California (the "Bankruptcy Court"). On December 19, 2007, the Bankruptcy Court entered an order confirming the Plan of Reorganization (the "Plan") filed by Calpine Corporation and related debtors, including Geysers Power Company LLC. The Plan became effective on January 31, 2008. Pursuant to the Plan, Geysers Power Company LLC assumed the purchase and sale agreements. 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:

Utility Facility[1]			At December 31, 2007
(in millions)	Series	Termination Date	Commitment
Pollution control bond – bank reimbursement agreements	96 C, E, F, 97 B	February 2012	$ 620
Pollution control bond – bond insurance reimbursement agreements	96 A	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 bond insurance companies.

Generally, under the loan agreements related to the Utility's pollution control bonds, the Utility, among other things, agrees to pay principal, interest, or any premium on the bonds to the trustee in accordance with the relevant indentures, maintain and repair the underlying projects financed by such bonds, and not take any action or fail to take any action if any such action or inaction would cause the interest on the bonds to be taxable or to be other than "exempt facility bonds" within the meaning of Section 142(a) of the Code.

In 2005, the Utility purchased a financial guaranty insurance policy to insure the regularly scheduled payment of principal and interest on $454 million of pollution control bonds series 2005 A-G ("PC2005 bonds") issued by the California Infrastructure and Economic Development Bank. In January 2008, the insurer's credit rating was downgraded and/or put on review for possible downgrade by several credit agencies. This has resulted in increases in interest rates for the PC2005 bonds, which rates are currently set at auction every 7 or 35 days. To minimize this interest rate exposure, the Utility intends to exercise its right to purchase the bonds in lieu of redemption and remarket the bonds when market conditions are more favorable. The purchase of the PC2005 bonds is expected to be financed through issuance of long-term debt.

Repayment Schedule

At December 31, 2007, 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)	2008	2009	2010	2011	2012	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%	–	5.66%	5.37%
Fixed rate obligations	–	$ 600	–	$ 500	–	$5,745	$6,845
Variable interest rate as of December 31, 2007	–	–	–	–	3.56%	4.47%	3.95%
Variable rate obligations	–	–	–	–	$ 614[1]	$ 454	$1,068
Total consolidated long-term debt	–	$ 600	$ 280	$ 500	$ 614	$6,199	$8,193

(1) The $614 million pollution control bonds, due in 2026, are backed by letters of credit which expire on February 24, 2012. 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 2012.

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, 2007:

(in millions) At December 31, 2007

Authorized Borrower	Facility	Termination Date	Facility Limit	Letters of Credit Outstanding	Cash Borrowings	Commercial Paper Backup	Availability
PG&E Corporation	Senior credit facility	February 2012	$ 200(1)	$ –	$ –	$ –	$ 200
Utility	Working capital facility	February 2012	2,000(2)	165	250	270	1,315
Total credit facilities			$2,200	$165	$250	$270	$1,515

(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 ("senior credit facility") with a syndicate of lenders that expires on February 26, 2012. 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. 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 ("S&P") and Moody's Investors Service ("Moody's").

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.

At December 31, 2007, PG&E Corporation had no outstanding borrowings or letters of credit under the senior credit facility.

UTILITY

In the ordinary course of the Utility's construction activities, contractors who work on and provide materials to projects may have certain statutory liens on such projects, which are released as construction progresses and payments are made for their work or materials.

Working Capital Facility

On February 26, 2007, the Utility increased its revolving credit facility ("working capital facility") with a syndicate of lenders by $650 million to $2.0 billion and extended the facility to February 26, 2012. 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. There were no material changes to the terms, fees, interest rates, or covenants related to the working capital facility as a result of the February 2007 amendment.

Letters of credit issued under the working capital facility are used primarily to provide credit enhancements to counterparties for natural gas and energy procurement transactions. At December 31, 2007, there were approximately $165 million of letters of credit and $250 million of borrowings outstanding under the working capital facility. In addition, the Utility treats the amount of its outstanding commercial paper as a reduction to the amount available under its working capital facility to provide liquidity support for outstanding commercial paper, as discussed below.

Accounts Receivable Facility

On February 26, 2007, in connection with the amendment of the working capital facility described above, the Utility terminated its $650 million accounts receivable facility that was scheduled to expire on March 5, 2007. There were no loans outstanding under the Utility's accounts receivable facility at the time of termination.

Commercial Paper Program

On June 28, 2007, the Utility increased its borrowing capacity under the commercial paper program from $1.0 billion to $1.75 billion. Commercial paper borrowings are used primarily to cover fluctuations in cash flow requirements. Liquidity support for these borrowings is provided by available capacity under the working capital facility, as described above. The commercial paper may have maturities up to 365 days and ranks equally with the Utility's other unsubordinated and unsecured indebtedness. At December 31, 2007, the Utility had $270 million of commercial paper outstanding, including amortization of a $1 million discount, at an average yield of approximately 5.6%. 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 with 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. At December 31, 2006, the total amount of RRB principal outstanding was $290 million. The RRBs were paid in full when they matured on December 26, 2007 and there are no future principal or interest payments.

NOTE 6: ENERGY RECOVERY BONDS

In furtherance of the Chapter 11 Settlement Agreement, 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 ("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 remaining four outstanding classes range from 3.87% for the earliest maturing class 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 $1.9 billion at December 31, 2007 and $2.3 billion at December 31, 2006. The scheduled principal repayments for ERBs are reflected in the table below:

(in millions)	2008	2009	2010	2011	2012	Total
Utility						
Average fixed interest rate	4.19%	4.36%	4.49%	4.59%	4.66%	4.47%
Energy recovery bonds	$ 354	$ 370	$ 386	$ 404	$ 422	$1,936

While PERF is a wholly owned consolidated subsidiary of the Utility, it is legally separate from the Utility. The assets (including the recovery property) of PERF 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

National Energy & Gas Transmission, Inc. ("NEGT") 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. On October 29, 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. On the effective date, PG&E Corporation recorded a net of tax gain on disposal of NEGT of $684 million. Based on the additional information received from NEGT in 2005 regarding PG&E Corporation's 2004 and 2003 federal income tax returns, PG&E Corporation recorded $13 million in income from discontinued operations.

At December 31, 2007 and 2006, PG&E Corporation's Consolidated Balance Sheets included the following assets and liabilities related to NEGT:

(in millions)	2007	2006
Current Assets		
Income taxes receivable	$33	$ –
Current Liabilities		
Income taxes payable	–	89
Other	11	11
Noncurrent Liabilities		
Income taxes payable	74	–
Deferred income taxes	34	–
Other	14	15

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 379,646,276 shares were issued and outstanding at December 31, 2007 and 374,181,059 shares were issued and outstanding at December 31, 2006. Elm Power Corporation, a wholly owned subsidiary of PG&E Corporation, holds 24,665,500 of the outstanding shares.

Of the 379,646,276 shares issued and outstanding at December 31, 2007, 1,261,125 shares were granted as restricted stock as share-based compensation awarded under the PG&E Corporation Long-Term Incentive Program and the 2006 Long-Term Incentive Plan ("2006 LTIP") and 4,920,648 shares were issued upon the exercise of employee stock options, for the account of 401(k) plan participants, and for the Dividend Reinvestment and Stock Purchase Plan ("DRSPP"). (See Note 14 for further discussion.)

Stock Repurchases

On December 15, 2004, PG&E Corporation entered into an accelerated share repurchase agreement ("ASR") with Goldman Sachs & Co., Inc. ("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 ("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.

To reflect the potential dilution that existed while the obligations related to the ASRs were outstanding, PG&E Corporation treated approximately one million and two million additional shares of PG&E Corporation common stock as outstanding for purposes of calculating diluted EPS for 2006 and 2005, respectively (see Note 10 for further discussion). PG&E Corporation has no remaining obligation under the November 2005 ASR as of December 31, 2007.

UTILITY

The Utility is authorized to issue 800 million shares of its $5 par value common stock, of which 282,916,485 shares were issued and outstanding as of December 31, 2007 and 279,624,823 shares were issued and outstanding as of December 31, 2006. 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 that cumulative preferred dividends on its preferred stock are paid.

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 under 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 common stock dividends of $476 million. Approximately $445 million of common stock dividends were paid to PG&E Corporation and the remaining amount was paid to PG&E Holdings, LLC. On April 15, July 15, and October 15, 2005, PG&E Corporation paid quarterly common stock dividends of $0.30 per share, totaling approximately $356 million, including approximately $22 million to Elm Power Corporation.

During 2006, the Utility paid common stock dividends of $494 million. Approximately $460 million of common stock dividends were paid to PG&E Corporation and the remaining amount was paid to PG&E Holdings, LLC. On January 16, April 15, July 15, and October 15, 2006, PG&E Corporation paid quarterly common stock dividends of $0.33 per share, totaling $489 million, including approximately $33 million to Elm Power Corporation.

During 2007, the Utility paid common stock dividends of $547 million. Approximately $509 million of 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.

On January 15, 2007, PG&E Corporation paid a quarterly common stock dividend of $0.33 per share. On April 15, July 15, and October 15, 2007, PG&E Corporation paid quarterly common stock dividends of $0.36 per share. The above dividend payments totaled $529 million, including approximately $35 million of common stock dividends paid to Elm Power Corporation. Elm Power Corporation held approximately 6% of PG&E Corporation's common stock.

On December 19, 2007, the Board of Directors of PG&E Corporation declared a dividend of $0.36 per share, totaling approximately $137 million that was paid on January 15, 2008 to shareholders of record on December 31, 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, 2007 and 2006, 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, 2007 and 2006, 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, 2007, 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. 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 years ended December 31, 2007 and December 31, 2006, the Utility paid approximately $14 million of dividends on preferred stock without mandatory redemption provisions. On December 19, 2007, the Board of Directors of the Utility declared a cash dividend on various series of its preferred stock totaling approximately $3 million that was paid on February 15, 2008 to shareholders of record on January 31, 2008. 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. PG&E Corporation's Convertible Subordinated Notes are entitled to receive pass-through dividends and meet the criteria of a participating security. All PG&E Corporation's participating securities participate on a 1:1 basis with shares of common stock.

PG&E Corporation applies the treasury stock method of reflecting the dilutive effect of outstanding stock-based compensation in the calculation of diluted EPS in accordance with SFAS No. 128. SFAS No. 128 requires that proceeds from the exercise of options and warrants are assumed to be used to purchase shares of common stock at the average market price during the reported period. The incremental shares (the difference between the number of shares assumed issued upon exercise and the number of shares assumed purchased) must be included in the number of weighted average shares of common stock used for the calculation of diluted EPS.

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

(in millions, except per share amounts)	Year ended December 31, 2007	2006	2005
Net Income	$1,006	$ 991	$ 917
Less: distributed earnings to common shareholders	508	460	449
Undistributed earnings	498	531	468
Less: undistributed earnings from discontinued operations	–	–	13
Undistributed earnings from continuing operations	$ 498	$ 531	$ 455
Common shareholders earnings			
Basic			
Distributed earnings to common shareholders	$ 508	$ 460	$ 449
Undistributed earnings allocated to common shareholders – continuing operations	472	503	433
Undistributed earnings allocated to common shareholders – discontinued operations	–	–	12
Total common shareholders earnings, basic	$ 980	$ 963	$ 894
Diluted			
Distributed earnings to common shareholders	$ 508	$ 460	$ 449
Undistributed earnings allocated to common shareholders – continuing operations	473	504	433
Undistributed earnings allocated to common shareholders – discontinued operations	–	–	12
Total common shareholders earnings, diluted	$ 981	$ 964	$ 894
Weighted average common shares outstanding, basic	351	346	372
9.50% Convertible Subordinated Notes	19	19	19
Weighted average common shares outstanding and participating securities, basic	370	365	391
Weighted average common shares outstanding, basic	351	346	372
Employee share-based compensation and accelerated share repurchases[1]	2	3	6
Weighted average common shares outstanding, diluted	353	349	378
9.50% Convertible Subordinated Notes	19	19	19
Weighted average common shares outstanding and participating securities, diluted	372	368	397
Net earnings per common share, basic			
Distributed earnings, basic[2]	$1.45	$1.33	$1.21
Undistributed earnings – continuing operations, basic	1.34	1.45	1.16
Undistributed earnings – discontinued operations, basic	–	–	0.03
Total	$2.79	$2.78	$2.40
Net earnings per common share, diluted			
Distributed earnings, diluted	$1.44	$1.32	$1.19
Undistributed earnings – continuing operations, diluted	1.34	1.44	1.15
Undistributed earnings – discontinued operations, diluted	–	–	0.03
Total	$2.78	$2.76	$2.37

(1) Includes approximately one million and two million shares of PG&E Corporation common stock treated as outstanding in connection with accelerated share repurchase agreements for 2006 and 2005, respectively. The remaining shares of approximately two million at December 31, 2006 and four million at December 31, 2005 relate to share-based compensation and are deemed to be outstanding under SFAS No. 128 for the purpose of calculating EPS. PG&E Corporation has no remaining obligation under these ASRs as of December 31, 2007. See the 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 7,285 and 28,500 shares were excluded from the computation of diluted EPS for 2007 and 2005, 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)	2007	2006	2005	2007	2006	2005
Current:						
Federal	$526	$ 743	$1,027	$563	$ 771	$1,048
State	140	201	189	149	210	196
Deferred:						
Federal	(81)	(286)	(574)	(92)	(276)	(572)
State	(40)	(98)	(89)	(43)	(97)	(89)
Tax credits, net	(6)	(6)	(9)	(6)	(6)	(9)
Income tax expense	$539	$ 554	$ 544	$571	$ 602	$ 574

The following describes net deferred income tax liabilities:

	PG&E Corporation		Utility	
	Year ended December 31,			
(in millions)	2007	2006	2007	2006
Deferred income tax assets:				
Customer advances for construction	$ 143	$ 170	$ 143	$ 170
Reserve for damages	173	165	173	165
Environmental reserve	172	177	172	177
Compensation	162	131	129	95
Other	289	206	261	166
Total deferred income tax assets	$ 939	$ 849	$ 878	$ 773
Deferred income tax liabilities:				
Regulatory balancing accounts	$1,219	$1,305	$1,219	$1,305
Property related basis differences	2,290	2,142	2,293	2,142
Income tax regulatory asset	298	243	298	243
Unamortized loss on reacquired debt	110	120	110	120
Other	75	27	66	53
Total deferred income tax liabilities	$3,992	$3,837	$3,986	$3,863
Total net deferred income tax liabilities	$3,053	$2,988	$3,108	$3,090
Classification of net deferred income tax liabilities:				
Included in current liabilities	$ –	$ 148	$ 4	$ 118
Included in noncurrent liabilities	3,053	2,840	3,104	2,972
Total net deferred income tax liabilities	$3,053	$2,988	$3,108	$3,090

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

	PG&E Corporation			Utility		
	Year ended December 31,					
	2007	2006	2005	2007	2006	2005
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)	4.2	4.3	4.5	4.3	4.6	4.6
Effect of regulatory treatment of fixed asset differences	(3.0)	(1.2)	(0.6)	(2.9)	(1.1)	(0.6)
Tax credits, net	(0.7)	(0.6)	(1.0)	(0.7)	(0.6)	(0.9)
Other, net	(0.6)	(1.6)	(0.3)	0.1	0.1	(0.1)
Effective tax rate	34.9%	35.9%	37.6%	35.8%	38.0%	38.0%

In recent months PG&E Corporation reached settlements on a number of its open tax years with the IRS.

In the first quarter of 2008, PG&E Corporation reached a settlement with the IRS appellate division for tax years 1997–2000. This settlement would not result in material changes to unrecognized tax benefits recognized under FIN 48, and it would resolve all open issues for those years with the exception of reserving the right to file two refund claims. The most significant claim relates to the deferral of gains from power plant sales and income from recovery of transition costs during 1998 and 1999.

In addition, during the first quarter of 2008, PG&E Corporation reached a tentative settlement with the IRS for tax years 2001–2002. The IRS has indicated that it intends to apply aspects of this tentative settlement to resolution of later tax years. That settlement, if finalized, would resolve several significant deductions taken in the 2002 tax return with respect to assets abandoned at NEGT, as well as issues affecting the Utility. However, this settlement would be subject to approval by the Joint Committee on Taxation. Two issues are not part of the audit settlement and will be referred to the IRS appellate division. The most significant of these is a dispute over PG&E Corporation's entitlement to $104 million in synthetic fuel tax credits.

The IRS also has indicated that it intends to complete its audit examination of tax years 2003–2004 by June 2008. Based on the IRS' proposed adjustments, this audit could be resolved within the next 18 months.

Currently, PG&E Corporation has $247 million of federal capital loss carry forwards based on tax returns as filed from the disposition of NEGT stock in 2004, which, if not used by December 2009, will expire. The settlement of the 2001–2002 audit together with the completion of the 2003–2004 audit could result in utilization of a significant portion of the federal capital loss carry forwards. However, because the settlement of the 2003–2004 audit remains uncertain, no benefits have been recognized.

The settlement of the 2001–2002 audit and the completion of the 2003–2004 audit could also result in net changes to unrecognized tax benefits currently recorded pursuant to FIN 48 (see Note 2 for further discussion of the impact of adopting FIN 48).

The California Franchise Tax Board is currently auditing PG&E Corporation's 2004 and 2005 combined California income tax returns. To date, no adjustments have been proposed. In addition to the federal capital loss carry forwards, PG&E Corporation has $2.1 billion of California capital loss carry forwards based on tax returns as filed, the majority of which, if not used by 2008, will expire. PG&E Corporation believes it has accrued adequate reserves for tax years that are open for California tax purposes.

NOTE 12: DERIVATIVES AND HEDGING ACTIVITIES

The Utility enters into contracts to procure electricity, natural gas, nuclear fuel, and firm electricity transmission rights. Some of these contracts meet the definition of derivative instruments under SFAS No. 133. All derivative instruments, including instruments designated as cash flow hedges, are recorded at fair value and presented as price risk management assets and liabilities on the balance sheet (see table below). Changes in the fair value of derivative instruments are deferred and recorded in regulatory accounts because they are expected to be recovered or refunded through regulated rates. Under the same regulatory accounting treatment, changes in the fair value of cash flow hedges are also recorded in regulatory accounts, rather than being deferred in accumulated other comprehensive income.

On PG&E Corporation's and the Utility's Consolidated Balance Sheets, price risk management assets and liabilities associated with the Utility's electricity and gas procurement activities are presented on a net basis by counterparty as the right of offset exists, resulting in a net asset or liability as follows:

	Derivatives	
(in millions)	December 31, 2007	December 31, 2006
Current Assets – Prepaid expenses and other	$ 52	$ 16
Other Noncurrent Assets – Other	125	37
Current Liabilities – Other	83	192
Noncurrent Liabilities – Other	20	50

Derivative instruments may be designated as cash flow hedges when they hedge variable price risk associated with the purchase of commodities. Cash flow hedges are presented on a net basis by counterparty.

The table below represents the portion of the derivative balances that were designated as cash flow hedges:

	Cash Flow Hedges	
(in millions)	December 31, 2007	December 31, 2006
Current Assets – Prepaid expenses and other[1]	$(2)	$ 3
Other Noncurrent Assets – Other	33	8
Current Liabilities – Other	19	25
Noncurrent Liabilities – Other	3	–

(1) $2 million of the cash flow hedges in a liability position at December 31, 2007 relate to counterparties for which the total net derivatives position is a current asset.

The Utility also 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 Consolidated Balance Sheets. They are recorded and recognized in income using accrual accounting. Therefore, expenses are recognized in cost of electricity and cost of natural gas as incurred.

Net realized 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 dividend participation rights associated with PG&E Corporation's Convertible Subordinated Notes are recorded at fair value in PG&E Corporation's Consolidated Financial Statements in accordance with SFAS No. 133. (See Note 4 above for discussion of the Convertible Subordinated Notes.)

NOTE 13: NUCLEAR DECOMMISSIONING

The Utility's nuclear power facilities consist of two units at Diablo Canyon ("Diablo Canyon Unit 1" and "Diablo Canyon Unit 2") and the retired facility at Humboldt Bay ("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 ("NRC") license and release of the property for unrestricted use. The Utility makes contributions to trust funds (described below) to provide for the eventual decommissioning of each nuclear unit. In the Utility's 2005 Nuclear Decommissioning Cost Triennial Proceeding ("NDCTP"), used to determine the level of Utility trust contributions and related revenue requirement, the CPUC assumed that the eventual decommissioning of Diablo Canyon Unit 1 would be scheduled to begin in 2024 and be completed in 2044; that decommissioning of Diablo Canyon Unit 2 would be scheduled to begin in 2025 and be completed in 2041; and that decommissioning of Humboldt Bay Unit 3 would be scheduled to begin in 2009 and be completed in 2015.

As presented in the Utility's NDCTP, the estimated nuclear decommissioning cost for Diablo Canyon Units 1 and 2 and Humboldt Bay Unit 3 is approximately $2.19 billion in 2007 dollars (or approximately $5.42 billion in future dollars). These estimates are based on the 2005 decommissioning cost studies, prepared in accordance with CPUC requirements. The Utility's revenue requirements for nuclear decommissioning costs (i.e., the revenue requirements used by the Utility to make contributions to the decommissioning trust funds) are recovered from customers through a non-bypassable charge that the Utility expects 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. However, under GAAP requirements, the decommissioning cost estimate is calculated using a different method in accordance with SFAS No. 143. Under GAAP, the Utility adjusts its nuclear decommissioning obligation to reflect the fair value of decommissioning its nuclear power facilities and records this as an asset retirement obligation on its Consolidated

Balance Sheet. The total nuclear decommissioning obligation accrued in accordance with GAAP was approximately $1.3 billion at December 31, 2007 and $1.2 billion at December 31, 2006. 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 in the fair value calculation. Differences between amounts collected in rates for decommissioning the Utility's nuclear power facilities and the decommissioning obligation recorded in accordance with GAAP are reflected in regulatory accounts. (See Note 3 of the Notes to the Consolidated Financial Statements.)

Decommissioning costs recovered in rates are placed in nuclear decommissioning trusts. 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 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, in order 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 60% 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 5.33% and in the non-qualified trusts to be 4.22%. Trust earnings are included in the nuclear decommissioning trust assets and the corresponding asset retirement costs 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.

During 2007, the trusts earned approximately $77 million in interest and dividends. 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, 2007, the Utility had accumulated nuclear decommissioning trust funds with an estimated fair value of approximately $2.0 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 2007, total unrealized losses on the investments held in the trusts were $7 million. SFAS Nos. 115-1 and 124-1 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 $7 million impairment is not other-than-temporary. As a result, an impairment loss was recognized and the Utility recorded a $7 million reduction to the nuclear decommissioning trusts assets and the asset retirement costs 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	Amortized Cost	Total Unrealized Gains	Total Unrealized Losses	Estimated Fair Value[1]
Year ended December 31, 2007					
U.S. government and agency issues	2008–2037	$ 767	$ 59	$–	$ 826
Municipal bonds and other	2008–2049	209	5	–	214
Equity securities		464	682	(7)	1,139
Total		$1,440	$746	$(7)	$2,179
Year ended December 31, 2006					
U.S. government and agency issues	2007–2036	$ 781	$ 34	$(1)	$ 814
Municipal bonds and other	2007–2049	252	7	(1)	258
Equity securities		347	644	–	991
Total		$1,380	$685	$(2)	$2,063

(1) Excludes taxes on appreciation of investment value.

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)	2007	2006	2005
Proceeds received from sales of securities	$830	$1,087	$2,918
Gross realized gains on sales of securities held as available-for-sale	61	55	56
Gross realized losses on sales of securities held as available-for-sale	(42)	(29)	(14)

SPENT NUCLEAR FUEL STORAGE PROCEEDINGS

As part of the Nuclear Waste Policy Act of 1982, Congress authorized the U.S. Department of Energy ("DOE") and electric utilities with commercial nuclear power plants to enter into contracts under which the DOE would be required to dispose of the utilities' spent nuclear fuel and high-level radioactive waste no later than January 31, 1998, in exchange for fees paid by the utilities. In 1983, the DOE entered into a contract with the Utility to dispose of nuclear waste from the Utility's two nuclear generating units at Diablo Canyon and its retired nuclear facility at Humboldt Bay. The DOE failed to develop a permanent storage site by January 31, 1998. The Utility believes that the existing spent fuel pools at Diablo Canyon (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.

Because the DOE failed to develop a permanent storage site, the Utility obtained a permit from the NRC to build an on-site dry cask storage facility to store spent fuel through at least 2024. After various parties appealed the NRC's issuance of the permit, the U.S. Court of Appeals for the Ninth Circuit issued a decision in 2006 requiring the NRC to issue a supplemental environmental assessment report on the potential environmental consequences in the event of a terrorist attack at Diablo Canyon, as well as to review other contentions raised by the appealing parties related to potential terrorism threats. In August 2007, the NRC staff issued a final supplemental environmental assessment report concluding there would be no significant environmental impacts from potential terrorist acts directed at the Diablo Canyon storage facility. On January 15, 2008, the NRC decided to hold hearings on whether it provided a complete list of the references upon which it relied to find that there would not be a significant environmental impact and whether it sufficiently addressed the impacts on land and the local economy of a potential terrorist attack. It is expected that the NRC will issue a final decision in the third quarter of 2008.

The Utility expects to complete the dry cask storage facility and begin loading spent fuel in 2008. If the Utility is unable to complete the dry cask storage facility, if operation of the facility is delayed beyond 2010, or 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 continued until such time as additional safe storage for spent fuel is made available.

The Utility and other nuclear power plant owners have sued the DOE for breach of contract. The Utility seeks to recover its costs to develop on-site storage at Diablo Canyon and Humboldt Bay Unit 3. In October 2006, the U.S. Court of Federal Claims found the DOE had breached its contract and awarded the Utility approximately $42.8 million of the $92 million incurred by the Utility through 2004. The Utility appealed to the U.S. Court of Appeals for the Federal Circuit seeking to increase the amount of the award and challenged the U.S. Court of Federal Claims' finding that the Utility would have incurred some of the costs for the on-site storage facilities even if the DOE had complied with the contract. A decision on the appeal is expected by the end of 2008. The Utility will seek to recover costs incurred after 2004 in future lawsuits against the DOE. Any amounts recovered from the DOE will be credited to customers through rates.

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. If the U.S. Court of Federal Claims' 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.

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 of 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.

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. Only the portion of the pension contribution allocated to the gas transmission and storage business is not recoverable in rates. For 2007, the reduction in net income as a result of the Utility not being able to recover this portion in rates was approximately $3 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, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans" ("SFAS No. 158") for the pension benefits related to the Utility's qualified benefit pension plan. Since 1993, the CPUC has authorized the Utility to recover the costs associated with its other benefits based on the lesser of the expense under SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions" ("SFAS No. 106"), or the annual tax deductible contributions to the appropriate trusts. This recovery mechanism does not allow the Utility to record a regulatory asset for the SFAS No. 158 charge to accumulated other comprehensive income related to other benefits. However, the Utility is not precluded from recording a regulatory liability as was done in 2007.

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 2007 and 2006:

Pension Benefits

	PG&E Corporation		Utility	
(in millions)	2007	2006	2007	2006
Projected benefit obligation at January 1	$9,064	$9,249	$9,023	$9,211
Service cost for benefits earned[1]	233	236	228	233
Interest cost	544	511	541	509
Actuarial gain	(397)	(592)	(396)	(594)
Plan amendments	1	1	2	3
Benefits and expenses paid	(364)	(341)	(362)	(339)
Projected benefit obligation at December 31	$9,081	$9,064	$9,036	$9,023
Accumulated benefit obligation	$8,243	$8,178	$8,206	$8,145

(1) This amount includes $2 million for the transfer of obligation from severance to the PG&E Enterprise Supplemental Executive Retirement Plan ("SERP") for PG&E Corporation.

Other Benefits

	PG&E Corporation		Utility	
(in millions)	2007	2006	2007	2006
Benefit obligation at January 1	$1,310	$1,339	$1,310	$1,339
Service cost for benefits earned	29	28	29	28
Interest cost	79	74	79	74
Actuarial gain	(66)	(105)	(66)	(105)
Plan amendments	17	31	17	31
Gross benefits paid	(97)	(92)	(97)	(92)
Federal subsidy on benefits paid	4	4	4	4
Participants paid benefits	35	31	35	31
Benefit obligation at December 31	$1,311	$1,310	$1,311	$1,310

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 2007 and 2006:

Pension Benefits

	PG&E Corporation		Utility	
(in millions)	2007	2006	2007	2006
Fair value of plan assets at January 1	**$9,028**	$8,049	**$9,028**	$8,049
Actual return on plan assets	**766**	1,050	**766**	1,050
Company contributions	**139**	300	**137**	298
Benefits and expenses paid	**(393)**	(371)	**(391)**	(369)
Fair value of plan assets at December 31	**$9,540**	$9,028	**$9,540**	$9,028

Other Benefits

	PG&E Corporation		Utility	
(in millions)	2007	2006	2007	2006
Fair value of plan assets at January 1	**$1,256**	$1,146	**$1,256**	$1,146
Actual return on plan assets	**107**	154	**107**	154
Company contributions	**38**	25	**38**	25
Plan participant contribution	**36**	31	**36**	31
Benefits and expenses paid	**(106)**	(100)	**(106)**	(100)
Fair value of plan assets at December 31	**$1,331**	$1,256	**$1,331**	$1,256

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)	2007	2006	2007	2006
Fair value of plan assets at December 31	**$ 9,540**	$ 9,028	**$ 9,540**	$ 9,028
Projected benefit obligation at December 31	**(9,081)**	(9,064)	**(9,036)**	(9,023)
Prepaid/(accrued) benefit cost	**$ 459**	$ (36)	**$ 504**	$ 5
Noncurrent asset	**$ 532**	$ 34	**$ 532**	$ 34
Current liability	**(2)**	(5)	**(3)**	(3)
Noncurrent liability	**(71)**	(65)	**(25)**	(26)
Prepaid/(accrued) benefit cost	**$ 459**	$ (36)	**$ 504**	$ 5

Other Benefits

	PG&E Corporation		Utility	
	December 31,		December 31,	
(in millions)	2007	2006	2007	2006
Fair value of plan assets at December 31	**$ 1,331**	$ 1,256	**$ 1,331**	$ 1,256
Benefit obligation at December 31	**(1,311)**	(1,310)	**(1,311)**	(1,310)
Prepaid/(accrued) benefit cost	**$ 20**	$ (54)	**$ 20**	$ (54)
Noncurrent asset	**$ 54**	$ –	**$ 54**	$ –
Noncurrent liability	**(34)**	(54)	**(34)**	(54)
Prepaid/(accrued) benefit cost	**$ 20**	$ (54)	**$ 20**	$ (54)

OTHER INFORMATION

The aggregate projected benefit obligation, accumulated benefit obligation, and fair value of plan assets 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, 2007 and 2006 were as follows:

	Pension Benefits		Other Benefits	
(in millions)	2007	2006	2007	2006
PG&E Corporation:				
Projected benefit obligation	$(73)	$(70)	$(187)	$(1,310)
Accumulated benefit obligation	(64)	(62)	–	–
Fair value of plan assets	–	–	153	1,256
Utility:				
Projected benefit obligation	$(27)	$(29)	$(187)	$(1,310)
Accumulated benefit obligation	(27)	(28)	–	–
Fair value of plan assets	–	–	153	1,256

COMPONENTS OF NET PERIODIC BENEFIT COST

Net periodic benefit cost as reflected in PG&E Corporation's Consolidated Statements of Income for 2007, 2006, and 2005 is as follows:

Pension Benefits

		December 31,	
(in millions)	2007	2006	2005
Service cost for benefits earned(1)	$ 233	$ 236	$ 214
Interest cost	544	511	500
Expected return on plan assets	(711)	(640)	(623)
Amortized prior service cost	49	56	56
Amortization of unrecognized loss	2	22	29
Net periodic benefit cost	$ 117	$ 185	$ 176

(1) This amount includes $2 million for the transfer of obligation from severance to the SERP for PG&E Corporation.

Other Benefits

		December 31,	
(in millions)	2007	2006	2005
Service cost for benefits earned	$ 29	$ 28	$ 30
Interest cost	79	74	74
Expected return on plan assets	(96)	(90)	(85)
Amortized prior service cost	16	14	11
Amortization of unrecognized gain	(10)	(3)	(1)
Amortization of transition obligation	26	26	26
Net periodic benefit cost	$ 44	$ 49	$ 55

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, "Employers' Accounting for Pensions," and SFAS No. 106.

Pre-tax amounts recognized in accumulated other comprehensive income consist of:

	PG&E Corporation		Utility	
(in millions)	2007	2006	2007	2006
Pension Benefits:				
Beginning unrecognized prior service cost	$(268)	$ –	$(275)	$ –
Adoption of SFAS No. 158	–	(268)	–	(275)
Current year unrecognized prior service cost	(3)	–	(2)	–
Amortization of unrecognized prior service cost	49	–	51	–
Unrecognized prior service cost	(222)	(268)	(226)	(275)
Beginning unrecognized net loss	(318)	–	(306)	–
Adoption of SFAS No. 158	–	(318)	–	(306)
Current year unrecognized net gain	421	–	423	–
Amortization of unrecognized net gain	2	–	–	–
Unrecognized net gain (loss)	105	(318)	117	(306)
Beginning unrecognized net transition obligation	(1)	–	(1)	–
Adoption of SFAS No. 158	–	(1)	–	(1)
Amortization of unrecognized net transition obligation	1	–	1	–
Unrecognized net transition obligation	–	(1)	–	(1)
Less: transfer to regulatory account[1]	109	574	109	574
Total	$ (8)	$ (13)	$ –	$ (8)
Other Benefits:				
Beginning unrecognized prior service cost	$(114)	$ –	$(114)	$ –
Adoption of SFAS No. 158	–	(114)	–	(114)
Current year unrecognized prior service cost	(18)	–	(18)	–
Amortization of unrecognized prior service cost	16	–	16	–
Unrecognized prior service cost	(116)	(114)	(116)	(114)
Beginning unrecognized net gain	250	–	250	–
Adoption of SFAS No. 158	–	250	–	250
Current year unrecognized net gain	71	–	71	–
Amortization of unrecognized net loss	(10)	–	(10)	–
Unrecognized net gain	311	250	311	250
Beginning unrecognized net transition obligation	(154)	–	(154)	–
Adoption of SFAS No. 158	–	(154)	–	(154)
Amortization of unrecognized net transition obligation	26	–	26	–
Unrecognized net transition obligation	(128)	(154)	(128)	(154)
Less: transfer to regulatory account[2]	(44)	–	(44)	–
Total	$ 23	$ (18)	$ 23	$ (18)

(1) The Utility recorded approximately $109 million in 2007 and $574 million in 2006 as a reduction to the existing pension regulatory liability in accordance with the provisions of SFAS No. 71.

(2) The Utility recorded approximately $44 million in 2007 as an addition 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 2008 are as follows:

(in millions)	PG&E Corporation	Utility
Pension benefits:		
Unrecognized prior service cost	$ 47	$ 48
Unrecognized net loss	1	–
Total	$ 48	$ 48
Other benefits:		
Unrecognized prior service cost	$ 16	$ 16
Unrecognized net gain	(17)	(17)
Unrecognized net transition obligation	26	26
Total	$ 25	$ 25

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,		
	2007	2006	2005	2007	2006	2005
Discount rate	6.31%	5.90%	5.60%	5.52–6.42%	5.50–6.00%	5.20–5.65%
Average rate of future compensation increases	5.00%	5.00%	5.00%	–	–	–
Expected return on plan assets	7.40%	8.00%	8.00%	7.00–7.50%	7.30–8.20%	7.60–8.40%

The assumed health care cost trend rate for 2007 is approximately 8%, 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	$72	$(59)
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 pension plan, the assumed return of 7.4% compares to a ten-year actual return of 7.9%. 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, 2007. 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 2007, 2006, and 2005.

ASSET ALLOCATIONS

The asset allocation of PG&E Corporation's and the Utility's pension and other benefit plans at December 31, 2007 and 2006, and target 2008 allocation, were as follows:

	Pension Benefits			Other Benefits		
	2008	2007	2006	2008	2007	2006
Equity securities						
U.S. equity	32%	**30%**	38%	37%	**36%**	49%
Non-U.S. equity	18%	**18%**	18%	18%	**19%**	20%
Global equity	5%	**5%**	5%	4%	**4%**	4%
Absolute return	5%	**5%**	0%	4%	**3%**	0%
Fixed income securities	40%	**41%**	39%	36%	**37%**	27%
Cash	0%	**1%**	0%	1%	**1%**	0%
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.

During 2007, the duration of fixed income assets was extended to better align with the interest rate sensitivity of the benefit plan liability. The maturity of fixed income securities at December 31, 2007 ranged from zero to 60 years and the average duration of the bond portfolio was approximately 10.5 years. 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.

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

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 either passively or actively manage the combined portfolio against the benchmark. Active management covers approximately 70% of the U.S. equity, 80% of the non-U.S. equity, and virtually 100% of the fixed income and global security portfolios.

During 2007, PG&E Corporation began extending the benchmarks of its fixed income managers and began using interest rate swaps for certain plans in order to better match the interest rate sensitivity of the plans' assets with that of the plans' liabilities. Changes in the value of these investments will affect future contributions to the trust and net periodic benefit cost on a lagged basis.

CASH FLOW INFORMATION

Employer Contributions

PG&E Corporation and the Utility contributed approximately $139 million to the pension benefits, including $134 million to the qualified defined benefit pension plan, and approximately $38 million to the other benefit plans in 2007. These contributions are consistent with PG&E Corporation's and the Utility's funding policy, which is to contribute amounts that are tax-deductible and 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 2007. 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 annually during 2008, 2009, and 2010 to the pension plan and expect to make contributions of approximately $58 million annually for the years 2008, 2009, and 2010 to other postretirement benefit plans.

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		
2008	$ 426	$ 424
2009	456	453
2010	485	483
2011	514	512
2012	544	541
2013–2017	3,179	3,164
Other benefits		
2008	$ 92	$ 92
2009	95	95
2010	96	96
2011	98	98
2012	98	98
2013–2017	516	516

DEFINED CONTRIBUTION BENEFIT PLANS

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. Before April 1, 2007, PG&E Corporation employees received matching of up to 5% of the employee's base compensation and/or basic contributions of up to 5% of the employee's base compensation. Matching contributions vary up to 6% based on years of service for Utility employees. Beginning April 1, 2007, the basic employer contribution was discontinued for PG&E Corporation employees and matching contributions were changed to match the Utility employee plan. 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,		
2007	**$47**	**$46**
2006	45	43
2005	43	42

PG&E Corporation Supplemental Retirement Savings Plan

The PG&E Corporation Supplemental Retirement Savings Plan ("SRSP") is a non-qualified plan that allows eligible officers and key employees of PG&E Corporation and its subsidiaries to defer 5% to 50% of their base salary and all or part of their incentive awards. In addition, to the extent that matching employer contributions cannot be made to a participant under the qualified defined contribution benefit plan because the contributions would exceed the limitations set by the Internal Revenue Code, PG&E Corporation credits the excess amount to an SRSP account for the eligible employee. Each SRSP participant has a separate account which is adjusted on a quarterly basis to reflect the performance of the investment options selected by the participant. The change in the value of participants' accounts 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
Year ended December 31,		
2007	**$2**	**$1**
2006	4	2
2005	3	1

LONG-TERM INCENTIVE PLAN

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 10,847,999 shares were available for award at December 31, 2007.

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 and the Utility for share-based incentive awards for the year ended December 31, 2007:

	Year ended December 31, 2007	
(in millions)	PG&E Corporation	Utility
Stock Options	$ 7	$ 4
Restricted Stock	24	15
Performance Shares	(8)	(7)
Total Compensation Expense (pre-tax)	**$23**	**$12**
Total Compensation Expense (after-tax)	**$14**	**$ 7**

	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

Stock Options

Other than the grant of options to purchase 7,285 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 2007. 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 ten-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 $7.81, $6.98, and $10.08 per share in 2007, 2006, and 2005, respectively. The significant assumptions used for shares granted in 2007, 2006, and 2005 were:

	2007	2006	2005
Expected stock price volatility	16.5%	22.1%	40.6%
Expected annual dividend payment	$1.44	$1.32	$1.20
Risk-free interest rate	4.73%	4.46%	3.74%
Expected life	5.4 years	5.6 years	5.9 years

Expected volatilities are based on historical volatility of PG&E Corporation's common stock. The expected dividend payment is the dividend yield at the date of grant. 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 expected life of stock options is derived from historical data that estimates stock option exercises and employee departure behavior.

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 and the Utility in 2007, 2006, and 2005:

(in millions)	PG&E Corporation	Utility
2007:		
Intrinsic value of options exercised	$ 59	$34
2006:		
Intrinsic value of options exercised	$ 97	$51
2005:		
Intrinsic value of options exercised	$125	$57

The tax benefit from stock options exercised totaled $20 million and $31 million for the year ended December 31, 2007 and December 31, 2006, respectively, of which approximately $11 million and $44 million was recorded by the Utility.

The following table summarizes stock option activity for PG&E Corporation and the Utility for 2007:

Options	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1	6,398,970	$23.52		
Granted[1]	7,285	$47.27		
Exercised	(2,419,272)	$24.30		
Forfeited or expired	(104,311)	$29.28		
Outstanding at December 31	**3,882,672**	**$24.00**	**4.38**	**$74,131,879**
Expected to vest at December 31	**872,088**	**$31.00**	**6.50**	**$10,619,107**
Exercisable at December 31	**2,999,566**	**$21.93**	**3.75**	**$63,459,514**

(1) No stock options were awarded to employees in 2007; however, certain non-employee directors of PG&E Corporation were awarded stock options.

The following table summarizes stock option activity for the Utility for 2007:

Options	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1[1]	4,402,506	$23.66		
Granted	–	–		
Exercised	(1,414,078)	$23.89		
Forfeited or expired	(77,563)	$29.92		
Outstanding at December 31[1]	**2,910,865**	**$23.40**	**4.49**	**$57,312,688**
Expected to vest at December 31	**613,950**	**$30.65**	**6.41**	**$ 7,726,688**
Exercisable at December 31	**2,289,714**	**$21.43**	**3.97**	**$49,586,001**

(1) Includes net employee transfers between PG&E Corporation and the Utility.

As of December 31, 2007, there was approximately $2 million of total unrecognized compensation cost related to outstanding stock options, of which $1 million was allocated to the Utility. That cost is expected to be recognized over a weighted average period of 0.5 years for PG&E Corporation and the Utility.

Restricted Stock

During 2007, PG&E Corporation awarded 607,459 shares of PG&E Corporation restricted common stock to eligible participants of PG&E Corporation and its subsidiaries, of which 428,960 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 ("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 and 2007, 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 the third year. 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 the fifth year. Compensation expense related to the portion of the 2007 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 2007 and 2006 totaled $7 million and $4 million, respectively, of which approximately $5 million and $2 million was recorded by the Utility.

The following table summarizes restricted stock activity for PG&E Corporation and the Utility for 2007:

	Number of Shares of Restricted Stock	Weighted Average Grant-Date Fair Value
Nonvested at January 1	1,377,538	$29.27
Granted	607,459	$45.82
Vested	(655,978)	$23.19
Forfeited	(67,894)	$39.67
Nonvested at December 31	**1,261,125**	**$39.84**

The following table summarizes restricted stock activity for the Utility for 2007:

	Number of Shares of Restricted Stock	Weighted Average Grant-Date Fair Value
Nonvested at January 1	932,728	$29.33
Granted	428,960	$45.82
Vested	(446,032)	$23.30
Forfeited	(60,244)	$39.69
Nonvested at December 31	**855,412**	**$39.97**

As of December 31, 2007, there was approximately $20 million of total unrecognized compensation cost relating to restricted stock, of which $15 million related to the Utility. The cost is expected to be recognized over a weighted average period of 1.4 years by PG&E Corporation and the Utility.

Performance Shares

During 2007, PG&E Corporation awarded 470,225 performance shares to eligible participants of PG&E Corporation and its subsidiaries, of which 320,495 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. A payout percentage is also taken into account, ranging from 0% to 200%, as measured by PG&E Corporation's TSR, relative to its comparator group, for the applicable three-year period. During 2007, PG&E Corporation paid $18.7 million to performance share recipients, of which $12.7 million related to Utility employees.

As of December 31, 2007, $21 million was accrued as the performance share liability for PG&E Corporation, of which $14.7 million related to the Utility. The number of performance shares that were outstanding at December 31, 2007 was 1,203,205, of which 853,868 was related to Utility employees. 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 comparator group.

NOTE 15: RESOLUTION OF REMAINING CHAPTER 11 DISPUTED CLAIMS

In connection with the Utility's reorganization under Chapter 11 of the U.S. Bankruptcy Code on April 12, 2004, the Utility deposited approximately $1.7 billion into escrow for the payment of certain Disputed Claims that had been made by generators and power suppliers for transactions that occurred during the 2000–2001 California energy crisis. The Disputed Claims are being addressed in various FERC and judicial proceedings seeking refunds on behalf of California electricity purchasers (including the State of California and the Utility) from electricity suppliers, including municipal and governmental entities, for overcharges incurred in the CAISO and the Power Exchange ("PX") wholesale electricity markets between May 2000 and June 2001. 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 Bankruptcy Court retains jurisdiction over the Utility's escrowed funds (in addition, 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 Utility's plan of reorganization under Chapter 11, and (3) the Bankruptcy Court's order confirming the plan of reorganization).

The Utility has entered into a number of settlements with various electricity suppliers resolving some of these Disputed Claims and the Utility's refund claims against these electricity suppliers. The Bankruptcy Court has approved the release of $0.8 billion from escrow in connection with these settlements. Through December 31, 2007, the Utility has received consideration of approximately $1.2 billion under these settlements through cash proceeds, reductions to the Utility's PX liability, and the acquisition of Gateway. 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 refund offset and interest issues being considered by the FERC.

During 2007, the Utility received approximately $79 million (including interest) in cash-equivalent reductions to the Utility's PX liability from five settlements approved by the FERC. The Utility also received two cash distributions in 2007 related to a prior settlement, totaling approximately $34 million. These distributions will be refunded to customers through rates. On December 21, 2007, the Utility requested FERC approval of another settlement, under which, if approved, the Utility would receive $45 million in cash-equivalent reductions to its PX liability. Additional settlement discussions with other electricity suppliers are ongoing. Any net refunds, claim offsets, or other credits that the Utility receives from energy suppliers through resolution of the remaining Disputed Claims, either through settlement or the conclusion of the various FERC and judicial proceedings, will be credited to customers (after deductions for contingencies based on the outcome of the various refund offset and interest issues being considered by the FERC).

As of December 31, 2007, the amount of the accrual for remaining net Disputed Claims was approximately $1.1 billion, consisting of approximately $1.6 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. The Utility held $1.2 billion (including interest) in escrow as of December 31, 2007 for payment of the remaining net Disputed Claims. The amount held in escrow is classified as Restricted Cash in the Consolidated Balance Sheets.

As of December 31, 2007, interest on the net Disputed Claims balance, calculated at the FERC-ordered interest rate, amounts to approximately $581 million (classified as Interest Payable in the Consolidated Balance Sheets). The rate of interest actually earned by the Utility on the escrowed amounts, however, is less than the FERC-ordered interest rate. The Utility has been collecting the difference between the earned amount and the accrued amount from customers. The amounts that have been collected from customers to address the difference between FERC-ordered and actual earned interest rates are not held in escrow. If the amount of interest accrued at the FERC-ordered rate is greater than the amount of interest ultimately determined to be owed to generators, the Utility would refund to customers any excess net interest collected from customers. The ultimate amount of any interest that the Utility may be required to pay will depend on the final amount of refunds determined to be owed to the Utility.

PG&E Corporation and the Utility are unable to predict when the FERC or judicial proceedings will ultimately be resolved, and the amount of any potential refunds that the Utility may receive or the amount of Disputed Claims, including interest, the Utility will be required to pay.

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 are priced at their fully loaded costs (i.e., direct cost of good or service plus all applicable indirect charges and overheads). PG&E Corporation also allocates various corporate administrative and general costs 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:

	Year ended December 31,			Receivable (Payable) Balance Outstanding at Year ended December 31,	
(in millions)	2007	2006	2005	2007	2006
Utility revenues from:					
Administrative services provided to PG&E Corporation	$ 4	$ 5	$ 5	$ 2	$ 2
Utility employee benefit assets due from PG&E Corporation	–	–	–	27	25
Interest from PG&E Corporation on employee benefit assets	1	1	–	–	–
Utility expenses from:					
Administrative services received from PG&E Corporation	$107	$108	$111	$(28)	$(40)
Utility employee benefit payments provided to PG&E Corporation	4	3	–	–	–

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 and the Utility also have significant contingencies arising from their operations, including contingencies related to guarantees, regulatory proceedings, nuclear operations, employee matters, environmental compliance and remediation, and legal matters.

COMMITMENTS

UTILITY

Third-Party Power Purchase Agreements

Qualifying Facility Power Purchase Agreements — Under the Public Utility Regulatory Policies Act of 1978 ("PURPA"), electric utilities were required to purchase energy and capacity from independent power producers that are qualifying co-generation facilities ("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 exceeds or fails to meet 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 the QF has nondiscriminatory access to one of three defined categories of competitive wholesale electricity markets. The statute permits such waivers 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 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 and to enter into new QF purchase obligations.

As of December 31, 2007, the Utility had agreements with 257 QFs for approximately 4,097 MW that are in operation. Agreements for approximately 3,754 MW expire at various dates between 2008 and 2028. QF power purchase agreements for approximately 343 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 74 inoperative QFs. The total of approximately 4,097 MW consists of approximately 2,524 MW from cogeneration projects, 580 MW from wind projects and 994 MW from projects with other fuel sources, including biomass, waste-to-energy, geothermal, solar, and hydroelectric. QF power purchase agreements accounted for approximately 20%, 20%, and 22% of the Utility's 2007, 2006, and 2005 electricity sources, respectively. No single QF accounted for more than 5% of the Utility's 2007, 2006, or 2005 electricity sources.

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 2008 to 2031. The Utility's irrigation district and water agency contracts accounted for approximately 3% of the Utility's 2007 electricity sources, approximately 6% of the Utility's 2006 electricity sources, and 5% of the Utility's 2005 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 2007, the Utility entered into several new renewable power purchase contracts that will help the Utility meet its goals. The CPUC's decision in the Utility's long-term procurement plan discussed below encourages the Utility to pursue the goal to meet 33% of its load with renewable resources by 2020.

Long-Term Power Purchase Agreements — In December 2007, the CPUC approved, with several modifications, the long-term electricity procurement plans ("LTPPs") of the California investor-owned electric utilities covering the 10-year period from 2007 through 2016. Each utility is required to submit an LTPP designed to reduce greenhouse gas emissions and uses the State of California's preferred loading order to meet forecasted demand (i.e., increases in future demand will be offset through energy efficiency programs, demand response programs, renewable generation resources, distributed generation resources, and new conventional generation). The decision notes that if a previously approved contract is terminated before the generation project is built, the utilities will retain the procurement authority for the MWs subject to the terminated contract. At the end of the solicitation or request-for-offer ("RFO") process, the utilities must justify why each bid was selected or rejected. Utilities can acquire ownership of new conventional generation resources in the utilities' competitive RFO process only through turnkey and engineering, procurement, and construction arrangements proposed by third parties. The utilities are required to submit revised LTPPs reflecting the changes required by the CPUC within 90 days of the date the decision is mailed.

Annual Receipts and Payments — The payments made under QFs, irrigation district and water agency, renewable energy, and other power purchase agreements during 2005 through 2007 were as follows:

(in millions)	2007	2006	2005
Qualifying facility energy payments	$ 812	$661	$663
Qualifying facility capacity payments	363	366	372
Irrigation district and water agency payments	72	64	54
Renewable energy and capacity payments	604	429	405
Other power purchase agreement payments	1,166	670	774

Because the Utility acts as only an agent for the DWR, the amounts described above do not include payments related to DWR power purchases allocated to the Utility's customers.

At December 31, 2007, 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
2008	$ 1,306	$ 464	$ 57	$ 26	$ 231	$14	$ 6	$232
2009	1,277	423	49	26	308	11	9	210
2010	1,159	389	67	22	346	7	8	159
2011	1,141	376	35	21	488	7	8	45
2012	1,029	345	30	21	524	7	8	18
Thereafter	7,063	2,213	72	53	6,840	–	11	2
Total	$12,975	$4,210	$310	$169	$8,737	$46	$50	$666

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)	
2008	$ 50
2009	50
2010	50
2011	50
2012	50
Thereafter	253
Total fixed capacity payments	503
Amount representing interest	131
Present value of fixed capacity payments	$372

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 capacity payments 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.

The Utility's Consolidated Balance Sheet has included in Current Liabilities – Other and Noncurrent Liabilities – Other approximately $28 million and $344 million, respectively, as of December 31, 2007, representing the present value of the fixed capacity payments due under these contracts. The corresponding assets of $372 million, including amortization of $36 million, are included in property, plant, and equipment on the Utility's Consolidated Balance Sheet at December 31, 2007.

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, 2007, the Utility's undiscounted obligations for natural gas purchases and gas transportation services were as follows:

(in millions)	
2008	$1,181
2009	222
2010	22
2011	14
2012	7
Thereafter	–
Total	$1,446

Payments for natural gas purchases and gas transportation services amounted to approximately $2.2 billion in 2007, $2.2 billion in 2006, and $2.5 billion in 2005.

Nuclear Fuel Agreements

The Utility has entered into several purchase agreements for nuclear fuel. These agreements have terms ranging from one to thirteen years and are intended to ensure long-term fuel supply. The contracts for uranium and conversion services provide for 100% coverage of reactor requirements through 2010, while contracts for enrichment services provide for 100% coverage of reactor requirements through 2009. The Utility relies on a number of international producers of nuclear fuel in order to diversify its sources and provide security of supply. Pricing terms also are diversified, ranging from market-based prices to base prices that are escalated using published indices. New agreements are primarily based on forward market pricing and will begin to impact nuclear fuel costs starting in 2010.

At December 31, 2007, the undiscounted obligations under nuclear fuel agreements were as follows:

(in millions)	
2008	$ 82
2009	82
2010	113
2011	98
2012	88
Thereafter	620
Total	$1,083

Payments for nuclear fuel amounted to approximately $102 million in 2007, $106 million in 2006, and $65 million in 2005.

Other Commitments and Operating Leases

The Utility has other commitments relating to operating leases, vehicle leasing, and telecommunication and information system contracts. At December 31, 2007, the future minimum payments related to other commitments were as follows:

(in millions)	
2008	$ 43
2009	16
2010	13
2011	12
2012	26
Thereafter	28
Total	$138

Payments for other commitments and operating leases amounted to approximately $38 million in 2007, $100 million in 2006, and $146 million in 2005.

Underground Electric Facilities

At December 31, 2007, the Utility was committed to spending approximately $236 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 indemnity obligations of its former subsidiary, NEGT, 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 not received any claims nor does it consider it probable that any claims will be made under the guarantee. At December 31, 2007, PG&E Corporation's potential exposure under this guarantee was immaterial and PG&E Corporation has not made any provision for this guarantee.

UTILITY

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 ("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 $38.5 million per one-year policy term.

NEIL also provides coverage for damages caused by acts of terrorism at nuclear power plants. Under the Terrorism Risk Insurance Program Reauthorization Act of 2007 ("TRIPRA"), acts of terrorism may be "certified" by the Secretary of the Treasury. For a certified act of terrorism, NEIL can obtain compensation from the federal government and will provide up to the full policy limits to the Utility for an insured loss. If one or more non-certified acts of terrorism cause property damage covered under any of the nuclear insurance policies issued by NEIL to any NEIL member, the maximum recovery under all those nuclear insurance policies may not exceed $3.24 billion within a 12-month period plus the additional amounts recovered by NEIL for these losses from reinsurance. TRIPRA extends the Terrorism Risk Insurance Act of 2002 through December 31, 2014.

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. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years. The next scheduled adjustment is due on or before 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 purchased under the DWR allocated contracts with various generators provided approximately 25% of the electricity delivered to the Utility's customers for the year ended December 31, 2007. 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 has stated publicly in the past that it intends to transfer full legal title of, 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 Utility's current issuer rating by Moody's is A3 and the Utility's long-term issuer credit rating by S&P is BBB+;
- The CPUC first makes a finding that the DWR power purchase contracts to be assumed are just and reasonable;
- 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.

On February 28, 2008, the CPUC is scheduled to vote on a proposed decision that states the CPUC would proactively investigate how the DWR can terminate its obligations under the power contracts, by assignment or otherwise, in order to hasten the reinstatement of direct access.

SEVERANCE IN CONNECTION WITH EFFORTS TO ACHIEVE COST AND OPERATING EFFICIENCIES

In connection with the Utility's initiatives to streamline processes and achieve cost and operating efficiencies, the Utility is eliminating and consolidating various employee positions. As a result, the Utility has incurred severance costs and expects that it will incur additional severance costs. The amount of future severance costs will depend on many variables, including whether affected employees elect to receive severance benefits or reassignment, the number of available vacant positions for those seeking reassignment and, for those employees who elect severance benefits, their years of service and annual salaries. At December 31, 2007, the Utility estimated future severance costs will range from $30 million to $74 million, given the uncertainty of each of these variables. The Utility has recorded a liability of $30 million as of December 31, 2007. The following table presents the changes in the liability from December 31, 2006:

(in millions)	
Balance at December 31, 2006	$ 34
Additional severance accrued	8
Less: Payments	(12)
Balance at December 31, 2007	**$ 30**

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 environmental laws. Under federal and California laws, the Utility may be responsible for remediation of hazardous substances at former manufactured gas plant sites, power plant sites, and sites used by the Utility for the storage, recycling, or disposal of potentially hazardous materials, 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. The liability is an estimate of costs for site investigations, remediation, operations and maintenance, monitoring and site closure, using current technology, and considering 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 and gross environmental remediation liability of approximately $528 million at December 31, 2007, and approximately $511 million at December 31, 2006. The $528 million accrued at December 31, 2007 consists of:

- Approximately $235 million for remediation at the Hinkley and Topock natural gas compressor sites;
- Approximately $90 million related to remediation at divested generation facilities;
- Approximately $152 million related to remediation costs for the Utility's generation and other facilities, 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); and
- Approximately $51 million related to remediation costs for the fossil decommissioning sites.

Of the approximately $528 million environmental remediation liability, approximately $132 million has been included in prior rate setting proceedings. The Utility expects that an additional amount of approximately $306 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 $834 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 $834 million does not include any estimate for any potential costs of remediation at former manufactured gas plant sites owned by others, unless the Utility has assumed liability for the site, the current owner has asserted a claim against the Utility, or the Utility has otherwise determined it is probable that a claim will be asserted.

In July 2004, the U.S. Environmental Protection Agency ("EPA") published regulations under Section 316(b) of the Clean Water Act that apply to existing electricity generation facilities that use over 50 million gallons of water per day, which typically include some form of "once-through" cooling in which water from natural bodies of water is used to cool a generating facility and the heated water is discharged back into the source. The Utility's Diablo Canyon power plant is among an estimated 539 generation facilities nationwide that are affected by this rulemaking. The EPA regulations are intended to reduce impacts to aquatic organisms by establishing a set of performance standards for cooling water intake structures. These regulations allow site-specific compliance measures if a facility's cost of compliance is significantly greater than either the benefits to be achieved or the compliance costs considered by the EPA. The EPA regulations also allow the use of environmental mitigation or restoration to meet compliance requirements in certain cases. In response to the EPA regulations, in June 2006, the California State Water Resources Control Board ("Water Board") published a draft policy for California's implementation of Section 316(b) that proposes to eliminate the EPA's site-specific compliance options, although the draft state policy would permit environmental restoration as a compliance option for nuclear facilities if the installation of cooling towers would conflict with a nuclear safety requirement. Various parties separately challenged the EPA's regulations in court, and the cases were consolidated in the U.S. Court of Appeals for the Second Circuit ("Second Circuit"). In January 2007, the Second Circuit remanded significant provisions of the regulations to the EPA for reconsideration and held that a cost-benefit test could not be used to comply with performance standards or to obtain a variance from the standards. The Second Circuit also ruled that environmental restoration cannot be used to comply with the standard. Petitions requesting U.S. Supreme Court review of the Second Circuit decision are pending, and the EPA has suspended its regulations. It is uncertain when the EPA will issue revised regulations, whether the Supreme Court will accept review of the Second Circuit decision, how judicial developments will affect the EPA's revised regulations, how judicial developments and the EPA's revised regulations will affect the Water Board's proposed policy, and when the Water Board will issue its final policy. Depending on the nature of the final regulations that may ultimately be adopted by the EPA or the Water Board, the Utility may incur significant capital expense to comply with the final regulations, which the Utility would seek to recover through rates. If either the final regulations adopted by the EPA or the Water Board require the installation of cooling towers at Diablo Canyon, and if installation of such cooling towers is not technically or economically feasible, the Utility may be forced to cease operations at Diablo Canyon.

CALIFORNIA LABOR CODE ISSUES

Approximately 12,929 of the Utility's employees are covered by collective bargaining agreements with three labor unions: (1) the International Brotherhood of Electrical Workers, Local 1245, AFL-CIO ("IBEW"); (2) the Engineers and Scientists of California, IFPTE Local 20, AFL-CIO and CLC, and (3) the Service Employees International Union, Local 24/7. Employees in California are entitled to an unpaid, uninterrupted 30-minute duty-free meal period for every four hours of work. California Labor Code Section 226.7 prohibits employers from requiring employees to work during any mandated meal. Employers who fail to provide the mandated meal period must provide the employee with one additional hour of pay at the employee's regular rate of compensation for each work day that the meal period is not provided. (If the employee worked during the 30-minute unpaid meal period, the employer must also pay the employee for this time.)

In April 2007, the California Supreme Court ruled that this California law requiring employers to pay an employee an additional hour of pay for each work day that a required meal is not provided is a "wage" rather than a penalty, subject to a three-year statute of limitations rather than the one-year statute of limitations for penalty payments. Prior to this decision, the Utility believed that its collective bargaining agreement with the IBEW, which did not provide certain employee groups a continuous 30-minute meal period, preempted state law.

In July 2007, the Utility established a joint committee composed of IBEW and Utility representatives to review the Utility's current collective bargaining agreements to ensure compliance with California labor law in light of the California Supreme Court's ruling. In June 2007, the Utility and the IBEW reached an agreement under which employees whose eight-hour shifts do not allow for an uninterrupted 30-minute meal break will be paid one hour of pay for each 30-minute meal period missed going back 39 months. In connection with this agreement, the Utility has expensed approximately $22 million as of December 31, 2007 for payments to approximately 2,000 employees. The Utility is continuing to investigate whether other employees may be entitled to payment for a missed or delayed meal. Until this investigation is complete, the Utility is unable to determine the amount of loss that it may incur in connection with this matter. The ultimate outcome of this matter may have a material adverse impact on PG&E Corporation's and the Utility's results of operations or financial condition.

LEGAL MATTERS

PG&E Corporation and the Utility are subject to various laws and regulations and, in the normal course of business, PG&E Corporation and the Utility are named as parties in a number of claims and lawsuits.

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 matter. 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 Current Liabilities – Other in the Consolidated Balance Sheets, and totaled approximately $78 million at December 31, 2007 and approximately $74 million at December 31, 2006.

After considering the above accruals, PG&E Corporation and the Utility do not expect that losses associated with legal matters will have a material impact 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
2007				
PG&E Corporation				
Operating revenues	$3,415	$3,279	$3,187	$3,356
Operating income	448	582	555	529
Income from continuing operations	203	278	269	256
Net income	203	278	269	256
Earnings per common share from continuing operations, basic	0.56	0.77	0.75	0.71
Earnings per common share from continuing operations, diluted	0.56	0.77	0.74	0.71
Net income per common share, basic	0.56	0.77	0.75	0.71
Net income per common share, diluted	0.56	0.77	0.74	0.71
Common stock price per share:				
High	48.56	47.87	50.89	47.71
Low	43.09	42.14	43.90	43.87
Utility				
Operating revenues	$3,416	$3,279	$3,187	$3,356
Operating income	453	585	556	531
Net income	206	283	274	261
Income available for common stock	203	279	270	258
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

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of PG&E Corporation and Pacific Gas and Electric Company ("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, 2007, 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, 2007.

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, 2007, appearing in this annual report and has issued an attestation report on the effectiveness of PG&E Corporation's and the Utility's internal control over financial reporting, as stated in their report, which is included in this annual report.

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 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, 2007 and 2006, and the related consolidated statements of income, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2007. These financial statements are the responsibility of the respective managements of the Company and 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, 2007 and 2006, and the respective results of their consolidated operations and their cash flows for each of the three years in the period ended December 31, 2007, 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 January 2007 the Company and the Utility adopted a new interpretation of accounting standards for uncertainty in income taxes. In 2006 the Company and the Utility adopted new accounting standards for defined benefit pensions and other postretirement plans and share-based payments.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's and the Utility's internal control over financial reporting as of December 31, 2007, 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, 2008 expressed an unqualified opinion on the effectiveness of the Company's and the Utility's internal control over financial reporting.

DELOITTE & TOUCHE LLP

San Francisco, California
February 21, 2008

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**:

- 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, the PG&E Corporation Compensation Committee, the companies' Executive Committees, the PG&E Corporation Finance Committee, the PG&E Corporation Nominating 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:

Vice President, Corporate Governance
and Corporate Secretary
Linda Y.H. Cheng
PG&E Corporation
One Market, Spear Tower, Suite 2400
San Francisco, CA 94105-1126

On May 17, 2007, 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, certifying that he was not aware of any violation by PG&E Corporation of the stock exchange's corporate governance listing standards.

DAVID R.
ANDREWS

LESLIE S. BILLER

DAVID A.
COULTER

C. LEE COX[2]

PETER A.
DARBEE

MARYELLEN C.
HERRINGER

RICHARD A.
MESERVE

MARY S. METZ

WILLIAM T.
MORROW[1]

BARBARA L.
RAMBO

BARRY
LAWSON
WILLIAMS

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
Maryellen C. Herringer
Mary S. Metz
William T. Morrow(1)
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

COMPENSATION COMMITTEE

Reviews employment, compensation, and benefits policies and practices. Recommends compensation for directors and the chief executive officers of PG&E Corporation and Pacific Gas and Electric Company. Reviews and approves compensation for other senior officers. Oversees the development, selection, and compensation of policy-making officers, and reviews long-range planning for officer development and succession.

C. Lee Cox, *Chair*
David A. Coulter
Barbara L. Rambo
Barry Lawson Williams

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 AND GOVERNANCE COMMITTEE

Recommends candidates for nomination as directors and reviews the composition and performance of the Boards of Directors. Recommends the chairmanship and membership of committees of the Boards of Directors, and the nominees for lead director. Reviews corporate governance matters, including the Corporate Governance Guidelines of PG&E Corporation and Pacific Gas and Electric Company.

Maryellen C. Herringer, *Chair*
David R. Andrews
Richard A. Meserve
Barbara L. Rambo

PUBLIC POLICY COMMITTEE

Reviews public policy and corporate responsibility 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, and 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
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 William T. Morrow 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

KENT M. HARVEY
Senior Vice President and
Chief Risk and Audit Officer

CHRISTOPHER P. JOHNS
Senior Vice President,
Chief Financial Officer, and Treasurer

NANCY E. MCFADDEN
Senior Vice President, Public Affairs

HYUN PARK
Senior Vice President
and General Counsel

GREG S. PRUETT
Senior Vice President,
Corporate Relations

RAND L. ROSENBERG
Senior Vice President,
Corporate Strategy and Development

JOHN R. SIMON
Senior Vice President, Human Resources

LINDA Y.H. CHENG
Vice President, Corporate Governance
and Corporate Secretary

STEVEN L. KLINE
Vice President, Corporate
Environmental and Federal Affairs

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

C. LEE COX
Non-Executive Chairman of the Board

WILLIAM T. MORROW
President and Chief Executive Officer

THOMAS E. BOTTORFF
Senior Vice President,
Regulatory Relations

HELEN A. BURT
Senior Vice President and
Chief Customer Officer

JOHN T. CONWAY
Senior Vice President and
Chief Nuclear Officer

CHRISTOPHER P. JOHNS
Senior Vice President and Treasurer

JOHN S. KEENAN
Senior Vice President and
Chief Operating Officer

PATRICIA M. LAWICKI
Senior Vice President and
Chief Information Officer

NANCY E. MCFADDEN
Senior Vice President, Public Affairs

EDWARD A. SALAS
Senior Vice President,
Engineering and Operations

JOHN R. SIMON
Senior Vice President, Human Resources

GEISHA J. WILLIAMS
Senior Vice President, Energy Delivery

WILLIAM D. ARNDT
Vice President, Project Management
and Program Office

OPHELIA B. BASGAL
Vice President, Civic Partnership
and Community Initiatives

JAMES R. BECKER
Site Vice President,
Diablo Canyon Power Plant

DESMOND BELL
Vice President, Shared Services and
Chief Procurement Officer

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 and Chief Diversity Officer

SANFORD L. HARTMAN
Vice President and
Managing Director, Law

WILLIAM D. HAYES
Vice President,
Maintenance and Construction

ROBERT T. HOWARD
Vice President,
Gas Transmission and Distribution

MARK S. JOHNSON
Vice President,
Electric Operations and Engineering

ROY M. KUGA
Vice President, Energy Supply

RANDAL S. LIVINGSTON
Vice President, Power Generation

DINYAR B. MISTRY
Vice President, Regulation and Rates

FONG WAN
Vice President, Energy Procurement

BRADLEY E. WHITCOMB
Vice President, Products and Services

SHAREHOLDER INFORMATION

For financial and other information about PG&E Corporation and Pacific Gas and Electric Company, please visit our websites, www.pgecorp.com and www.pge.com, respectively.

If you have questions about your PG&E Corporation common stock account or Pacific Gas and Electric Company preferred stock account, please write or call our transfer agent, BNY Mellon Shareowner Services:

BNY Mellon Shareowner Services
P. O. Box 358015
Pittsburgh, PA 15252-8015

Toll-free telephone services: 1.800.719.9056
Website: www.melloninvestor.com

If you have general questions about PG&E Corporation or Pacific Gas and Electric Company, please contact the Corporate Secretary's Office:

Vice President, Corporate Governance and Corporate Secretary
Linda Y. H. Cheng
PG&E Corporation
One Market, Spear Tower, Suite 2400
San Francisco, CA 94105-1126
415.267.7070
Fax 415.267.7268

Securities analysts, portfolio managers, or other representatives of the investment community should write or call the Investor Relations Office:

Vice President, Investor Relations
Gabriel B. Togneri
PG&E Corporation
One Market, Spear Tower, Suite 2400
San Francisco, CA 94105-1126
415.267.7080
Fax 415.267.7262

PG&E Corporation
General Information
415.267.7000

Pacific Gas and Electric Company
General Information
415.973.7000

Stock Exchange Listings
PG&E Corporation's common stock is traded on the New York and Swiss stock exchanges. The official New York Stock Exchange symbol is "PCG" but PG&E Corporation common stock is listed in daily newspapers under "PG&E" or "PG&E Cp."[1]

Pacific Gas and Electric Company has eight issues of preferred stock, all of which are listed on the American stock exchange.

Issue	Newspaper Symbol[1]
First Preferred, Cumulative, Par Value $25 Per Share	
Non-Redeemable:	
6.00%	PacGE pfA
5.50%	PacGE pfB
5.00%	PacGE pfC
Redeemable:	
5.00%	PacGE pfD
5.00% Series A	PacGE pfE
4.80%	PacGE pfG
4.50%	PacGE pfH
4.36%	PacGE pfI

2008 Dividend Payment Dates

PG&E Corporation Common Stock
January 15
April 15
July 15
October 15

Pacific Gas and Electric Company Preferred Stock
February 15
May 15
August 15
November 15

Stock Held in Brokerage Accounts ("Street Name")
When you purchase your stock and it is held for you by your broker, the shares are listed with BNY Mellon Shareowner Services in the broker's name, or "street name." BNY Mellon Shareowner Services does not know the identity of the individual shareholders who hold their shares in this manner. They simply know that a broker holds a number of shares that may be held for any number of investors. If you hold your stock in a street name account, you receive all tax forms, publications, and proxy materials through your broker. If you are receiving unwanted duplicate mailings, you should contact your broker to eliminate the duplications.

PG&E Corporation Dividend Reinvestment and Stock Purchase Plan
If you hold PG&E Corporation or Pacific Gas and Electric Company stock in your own name, rather than through a broker, you may automatically reinvest dividend payments from common and/or preferred stock in shares of PG&E Corporation common stock through the Dividend Reinvestment and Stock Purchase Plan (DRSPP). You may obtain a DRSPP prospectus and enroll by contacting BNY Mellon Shareowner Services. If your shares are held by a broker (in "street name"), you are not eligible to participate in the DRSPP.

Direct Deposit of Dividends
If you hold stock in your own name, rather than through a broker, you may have your common and/or preferred dividends transmitted to your bank electronically. You may obtain a direct deposit authorization form by contacting BNY Mellon Shareowner Services.

Replacement of Dividend Checks
If you hold stock in your own name and do not receive your dividend check within 10 days after the payment date, or if a check is lost or destroyed, you should notify BNY Mellon Shareowner Services so that payment can be stopped on the check and a replacement mailed.

Lost or Stolen Stock Certificates
If you hold stock in your own name and your stock certificate has been lost, stolen, or in some way destroyed, you should notify BNY Mellon Shareowner Services immediately.

(1) Local newspaper symbols may vary.

PG&E CORPORATION
PACIFIC GAS AND ELECTRIC COMPANY
ANNUAL MEETINGS OF SHAREHOLDERS

Date: May 14, 2008

Time: 10:00 a.m.

Location: San Ramon Valley Conference Center

3301 Crow Canyon Road

San Ramon, California

A joint notice of the annual meetings, joint proxy statement, and proxy card are being mailed with this annual report on or about April 2, 2008, to all shareholders of record as of March 17, 2008.

FORM 10-K

If you would like a copy of PG&E Corporation's and Pacific Gas and Electric Company's joint Annual Report on Form 10-K for the year ended December 31, 2007, (Form 10-K) that has been filed with the Securities and Exchange Commission, free of charge, please contact the Corporate Secretary's Office or visit our websites, www.pgecorp.com and www.pge.com.

The certifications of the principal executive officers and the principal financial officers of PG&E Corporation and Pacific Gas and Electric Company required by Section 302 of the Sarbanes-Oxley Act have been filed as exhibits to the Form 10-K.

Design: Pentagram Principal Photography: John Blaustein Peter Darbee Portrait and Board of Directors Photography: Jim Karageorge Photograph Page 15: Lewis Stewart

PG&E Corporation.

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