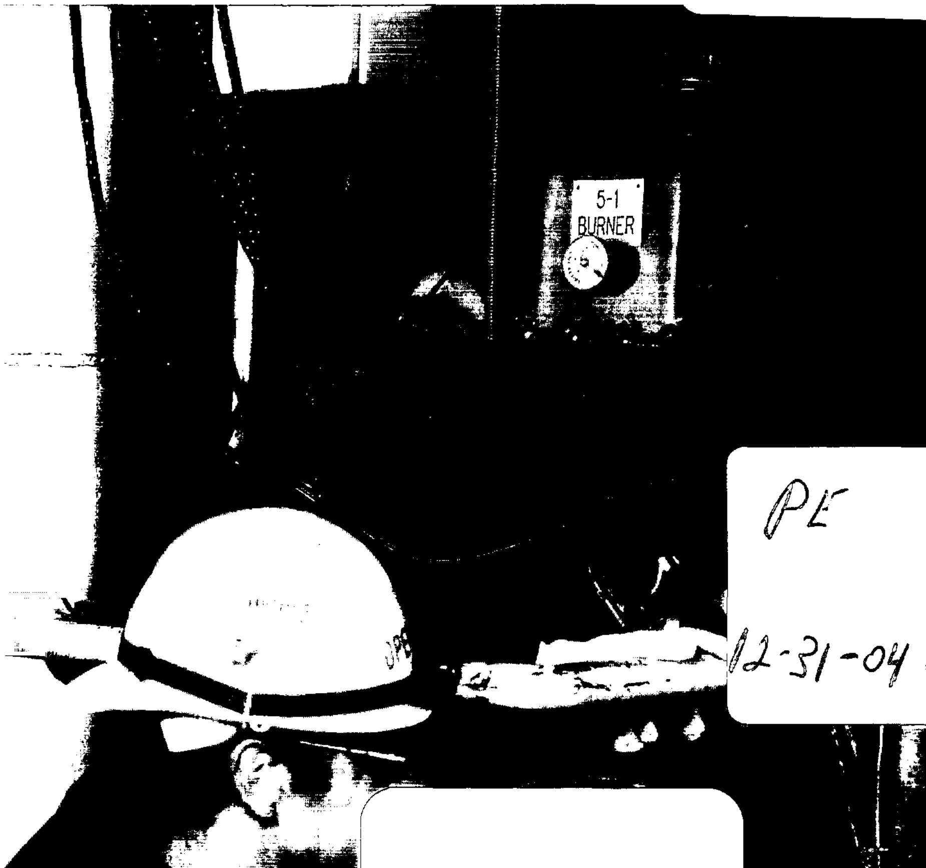
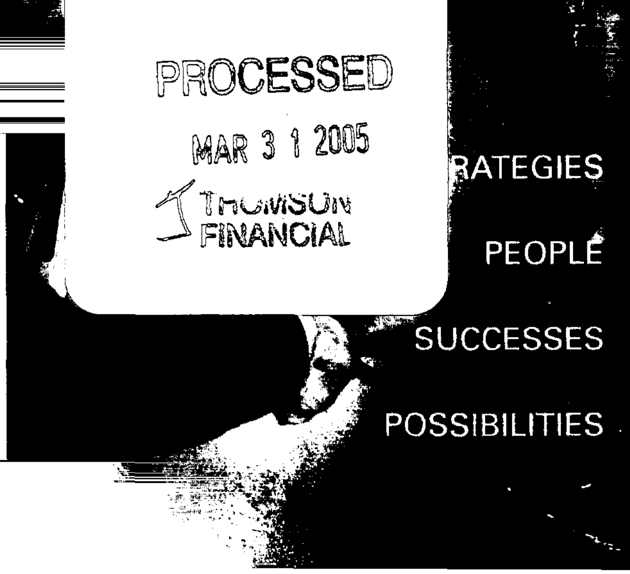
DTE Energy





real

STRATEGIES

PEOPLE

SUCCESSES

POSSIBILITIES

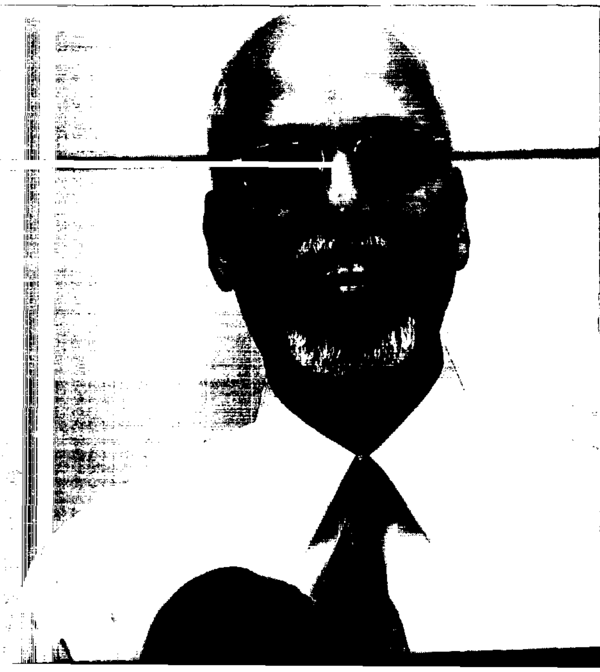
2004 annual report

about the cover

Solid, consistent strategies are positioning DTE Energy for growth. And with a work force that is genuinely committed to our success, we can actively pursue all possibilities that fit our disciplined plan.

Strategies, people, successes and possibilities . . . this is the real DTE Energy.

Pictured on front cover: Monroe Power Plant Operator George Horuczi; Tony Paradis, Lake Road Power Plant; Angela Boss, Coal Lab. Pictured on back cover (from left): Chuck Martin, John Baum and Bertrand Wilson.



From left: Senior Analyst Shariah A. Hill-Butler; Lineman Milton Hall Jr.; Customer Care Representative Heather Baker.

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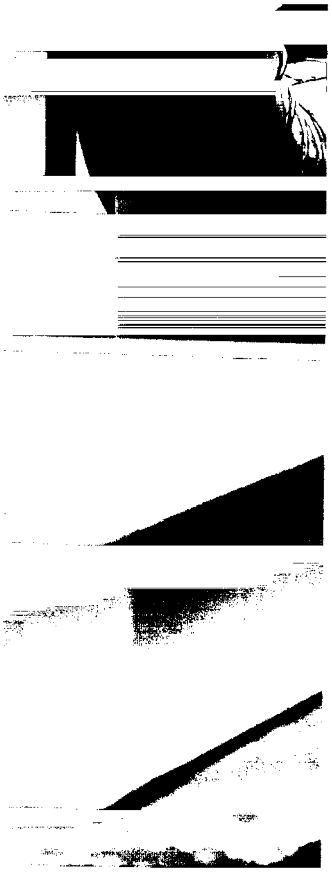
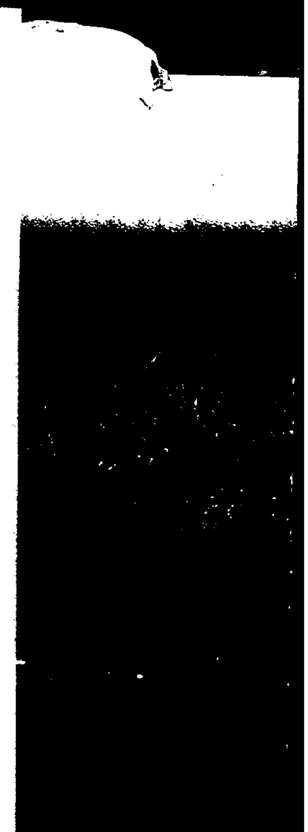
DTE Energy Services

From left: Carolyne Wass, Anthony Tarrance, and Stephanie Dorian. On screen: Purna Pai.

why invest?



- We maintain a portfolio of utility and non-utility businesses with varying risk/return profiles. This diversity provides stability to our earnings stream.
- Electric and gas utilities form our core operations. Regulated utilities are allowed to earn a fair return and provide a stable base of earnings for shareholders.
- We have an eight-year track record of successful growth in our non-utility businesses. Our strategy is linked to our core skills and assets, and is focused on creating value for our shareholders.
- We expect to generate approximately $1.65 billion of excess cash between now and 2008, and we have a solid plan to redeploy this cash and build shareholder value.
- We are committed to maintaining a healthy balance sheet and a strong investment-grade rating.
- We have provided attractive multi-year returns.
- We have provided a solid dividend with a high yield: 4.8 percent.



Lake Road Power Plant, Dayville, Conn.
Kevin Caldwell

DTE Energy businesses

utility

DETROIT EDISON

Electric Power Generation – Generate approximately 11,000 MW of power from nine fossil-fuel plants, one nuclear plant, a hydroelectric facility and 85 peaking generators in Michigan.
Electric Power Distribution – Own and operate approximately 660 distribution substations, maintain 44,000 miles of power lines and nearly 1 million utility poles, supplying electricity to 2.1 million customers in southeastern Michigan.

MICHCON

Gas Distribution – Provide gas sales and transportation delivery services to 1.2 million residential, commercial and industrial customers throughout Michigan. MichCon owns and operates 295 storage wells representing more than 5 percent of the nation's gas storage capacity.

non-utility

POWER AND INDUSTRIAL PROJECTS

Provide on-site energy services for large industrial customers in the auto, steel, and pulp and paper industries; steel-related projects such as synfuel and coke production, and pulverized coal injection; power generation with value-added services; and waste coal recovery projects.

UNCONVENTIONAL GAS PRODUCTION

Own interest in 22 percent of Michigan Antrim shale well production; lease almost 50,000 acres in Texas, with test drilling of the Barnett shale under way; and own and operate 29 landfill gas recovery sites in 12 states.

FUEL TRANSPORTATION AND MARKETING

Provide coal supply and transportation-related services across North America; own 40 percent interest in Vector pipeline and 10.5 percent interest in proposed Millennium pipeline; own or operate 70 Bcf of non-utility storage assets in Michigan; offer a full line of products and services to help manage energy purchase, generation and delivery.

From top: Belle River Power Plant, Mich.; Custer Wellhead, Mich.; Renaissance Center on-site services, Detroit, Mich.; biomass site, Riverview, Mich.; rail services facility, Hastings, N.C.

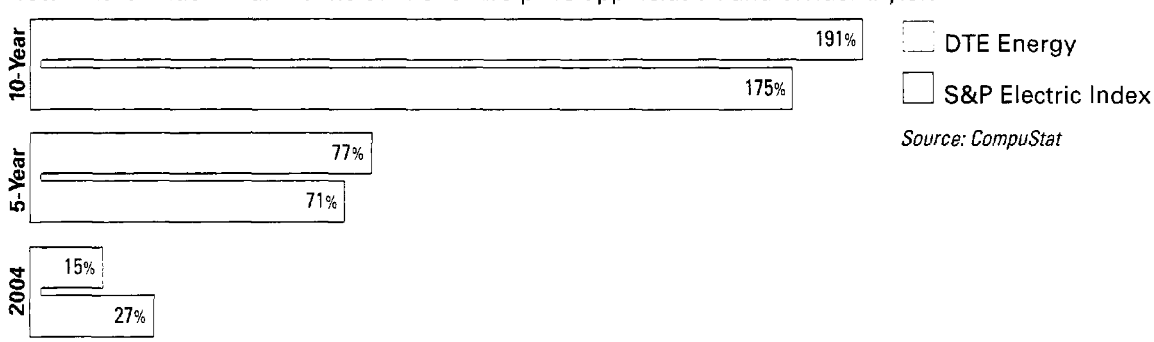
financial highlights

(Dollars in Millions, except Per Share Amounts)	2004	2003	% Change
Operating Revenues			
Electric Utility	$ 3,568	$ 3,695	(3.4) %
Gas Utility	1,682	1,498	12.3 %
Non-utility	2,495	2,119	17.7 %
Corporate & Other	16	12	33.3 %
Eliminations	(647)	(283)	N/A
	$ 7,114	$ 7,041	1.0 %
Net Income			
Electric Utility	$ 150	$ 252	(40.5) %
Gas Utility	20	29	(31.0) %
Non-utility	283	256	10.5 %
Corporate & Other	(10)	(57)	N/A
	443	480	(7.7) %
Discontinued Operations	(12)	68	(117.6) %
Cumulative Effect of Accounting Changes	-	(27)	-
	$ 431	$ 521	(17.3) %
Diluted Earnings Per Share			
Electric Utility	$ 0.87	$ 1.50	(42.0) %
Gas Utility	0.11	0.17	(35.3) %
Non-utility	1.63	1.52	7.2 %
Corporate & Other	(0.06)	(0.34)	(82.4) %
	2.55	2.85	(10.5) %
Discontinued Operations	(0.06)	0.40	(115.0) %
Cumulative Effect of Accounting Changes	-	(0.16)	-
	$ 2.49	$ 3.09	(19.4) %
Dividends Declared Per Share	$ 2.06	$ 2.06	-
Dividend Yield	4.8 %	5.2 %	(8.6) %
Average Common Shares Outstanding (Millions)			
Basic	173	168	3.0 %
Diluted	173	168	3.0 %
Book Value Per Share	$ 31.85	$ 31.36	1.6 %
Market Price at Year End	$ 43.13	$ 39.40	9.5 %
Total Market Capitalization	$ 7,514	$ 6,643	13.1 %
Investments and Capital Expenditures	$ 940	$ 785	19.7 %
Total Assets	$ 21,297	$ 20,753	2.6 %

total shareholder return

DTE Energy has consistently yielded strong performance for our shareholders.
Total shareholder return is the sum of share price appreciation and dividend yield.

cumulative total return



Source: CompuStat

From top: DTE Energy Hydrogen Techonology Park, Southfield, Mich.; Dick Redmond (left) and Dale Walker, DTE Oil and Gas; Matt Korzelius (left) and Brian LoTempio, on-site energy facility, Tonawanda, N.Y.

Chairman & Chief Executive Officer
Tony Earley

chairman's letter

real strategies

a track record of value

We faced enormous challenges in 2004. Fortunately, by year end most were behind us. I'm pleased with the progress we made. But at the same time, I'm disappointed with our earnings performance. We expected 2004 to be a low point in our business cycle and it was. The loss of revenue due to Michigan's Electric Choice program and the cost of implementation negatively impacted our bottom line by more than $85 million, or 50 cents a share, year-over-year.

Our diluted earnings per share were $2.49 in 2004 compared to $3.09 in 2003. In 2005, we should rebound above 2003 levels. We expect improvement across all of our business segments.

Before I describe our plans for 2005, I'd like to look back at 2004. Addressing regulatory concerns dominated our efforts. In November, the Michigan Public Service Commission (MPSC) issued a final order on our electric rate case. It was the first rate increase in 10 years for our electric subsidiary, Detroit Edison, and among the most complex in Michigan history. We received a $374 million increase in our base rates. In addition, the MPSC decision improved the certainty of cost recovery on a number of fronts that will help clear the way for Detroit Edison to earn a fair return.

In terms of fixing Michigan's Electric Choice program, the MPSC rate order was directionally correct. But there is still a lot of work to do on both the regulatory and legislative fronts. The most pressing issues are unbundling rates and eliminating subsidies for some rate classes (see Management's Discussion for more detail).

The rate case filed by our natural gas subsidiary, MichCon, was also the first in a decade. We expect to receive a final rate order in the first quarter of 2005. Because the order will be issued late in the 2005 heating season, we will not benefit fully until 2006.

We looked for only the very best investments and continued our non-utility growth for the eighth consecutive year.

Our second 2004 priority was to continue selling down our synfuel portfolio. We earn tax credits by processing particles of coal into an energy source. Because we can only use a limited number of tax credits in any given year, we accelerate cash generation by selling interests in our portfolio. By year end, we had sold more than 90 percent of our capacity, with plans to sell at least an additional 7 percent.

On-site energy facility, Sparrows Point, Md.
Mark Zolenas

We expect to generate approximately $1.65 billion of excess cash, primarily from synfuel, between 2005-2008. This cash presents a unique opportunity to increase shareholder value and strengthen our balance sheet. We have a solid plan to invest this cash that should help position our company for long-term growth. (Read more about this strategy in the sidebar of my letter.)

Our third 2004 priority was to sustain the company's growth momentum without stressing our balance sheet. We looked for only the very best investments and continued our non-utility growth for the eighth consecutive year. Our accomplishments include:

- Completing a deal with DaimlerChrysler to provide on-site energy services at eight sites in Michigan, Indiana and Ohio.
- Entering the pulp and paper industry for the first time with a deal to provide steam and electricity services to a tissue mill in Alabama.
- Growing our coke business. Currently we are the second largest producer of coke, a coal byproduct used to produce steel.
- Expanding our unconventional gas production from Antrim shale in Michigan and drilling test wells in the Barnett shale in Texas.
- Continuing solid performance from fuel transportation and marketing businesses.

Our fourth 2004 priority was to maintain cash and balance sheet strength. We lowered our leverage to 48 percent and achieved our cash generation goal through rigorous cost controls.

As a result of our efforts, we entered 2005 in a much stronger position than one year ago. We have identified six business priorities as critical to our success in 2005:

1. Achieve a sustainable Electric Choice program.
2. Develop a long-term regulatory strategy.
3. Continue our growth and value creation.
4. Achieve strong financial and balance sheet strength.
5. Make substantial progress toward achieving operational excellence.
6. Build an engaged work force.

Achieving a sustainable Electric Choice program will be a challenge in 2005, but we have already made progress. Last month, we complied with the MPSC order that we file a case to unbundle rates. Our goal is to restructure rates, establishing energy delivery and generation charges that reflect the true cost of serving each customer class. We also want to eliminate subsidies among rate classes that artificially skew the competitive environment.

We recognize that one of the key drivers of our future success is to ensure the regulatory process allows timely recovery of our prudent investments.

real strategies

From top: Jeff Harris, PepTec waste coal recovery; Art Sobiechowski, lineman specialist; Hurricane Ivan clean up; Timothy Lee, System Planning and Engineering.

Our second priority, is to develop a multi-year regulatory strategy that not only addresses current rate cases, but anticipates future investments in our system.

Our third priority is to continue growth and value creation. This involves investing cash in strong non-utility opportunities, as well as effectively growing our regulated utilities.

We expect net income from our non-utility businesses to increase approximately 30 percent in 2005. We also are developing a plan for regulated growth. It involves aggressively pursuing the business we've lost to Electric Choice over the past few years and looking for new business opportunities.

We do not, however, intend to grow at the expense of our balance sheet. We are committed to maintaining strong financial performance and balance sheet strength – our fourth priority.

To meet our targets for earnings per share and cash flow, we must remain vigilant in managing costs. Our fifth priority – progress toward achieving operational excellence – helps us keep this focus. As we improve the way we do business, our financial performance will improve.

The DTE Energy Operating System is helping streamline processes, eliminate waste and reduce costs. We are developing a culture that uses this approach on the job every day to boost performance and productivity. In 2004, we realized savings of approximately $105 million through various Operating System improvements. We've raised the bar even higher for 2005.

We are committed to maintaining strong financial and balance sheet performance.

Our largest Operating System initiative is a massive effort to replace our outdated and redundant information technology systems. As we phase in our new computer system and software, we will improve our procedures for finance, supply chain, human resources and operations. When this project is complete, we expect steady state annual savings of $75 million to $100 million.

Our final priority is to build an engaged work force with the commitment and skills needed to drive DTE Energy's success. This is a broad target that starts with an intense focus on safety. It involves training and developing our employees to ensure we have the right mix of skills and expertise for the future. It also involves building our talent pool of leaders by identifying,

From top: pipeline integrity improvement project, Southfield, Mich.; System Operations Center, Detroit, Mich.; Terry Harvill, Regulatory Affairs; Nancy Moody, Corporate and Governmental Affairs; Marty Nusbaum, energy center, Jeep assembly plant.

recruiting and developing high potential candidates, giving them opportunities to excel, and continuously refining our succession plans.

I was very pleased to announce last year the appointment of Gerry Anderson as president of DTE Energy. Gerry has served for the past six years as a group president overseeing our electric power plants and non-utility businesses, which have grown into an industry powerhouse under his leadership. While he still has these responsibilities, in his new role he also provides executive leadership for overall strategic planning and other critical initiatives.

Gerry and I are committed to delivering the type of value you have come to expect from DTE Energy. On behalf of all our employees, thank you for your continued support.

Anthony F. Earley Jr.

Anthony F. Earley Jr.
Chairman and Chief Executive Officer

March 1, 2005

President, DTE Energy
Gerry Anderson

real
strategies

our plan for reinvesting cash

We expect our non-utility businesses to generate $2 billion in cash flow over the next four years. This will provide a unique opportunity to build our company's value and shape its future. We intend to invest $350 million of this cash flow as equity in Detroit Edison to help fund our clean air investments. This leaves $1.65 billion to redeploy in other ways.

Our primary objectives in redeploying this cash are to:

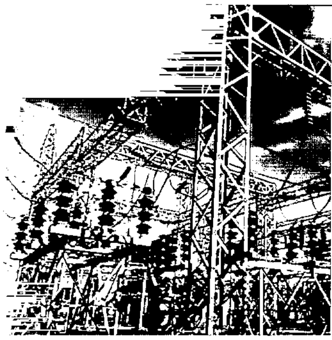
- Shape our balance sheet to meet both our near-term and long-term credit objectives.
- Replace and exceed the value of synfuel cash flow currently inherent in our stock price.

We expect to achieve these objectives by:

- Reducing parent company debt approximately one-third by 2008.
- Investing in new businesses that meet our strict risk-return and value-creation criteria. We believe we can successfully deploy $600 million to $900 million of capital into non-utility businesses from 2005-2008 at attractive returns.
- Repurchasing shares to help build value to the degree that adequate investment opportunities are not available.

It's an incredibly exciting time for DTE Energy. Our challenge is to invest our cash wisely – with discipline and a keen focus on building value. We're confident we will do that – and in the process – lay the foundation for a strong future.

Above: Coke battery operation, Gary, Ind.

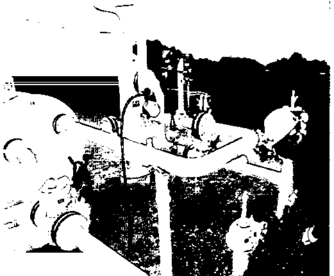


a legacy of excellence

utility businesses

Maintaining a strong utility base is at the heart of our business strategy. Our regulated utilities – Detroit Edison and MichCon – form the core of DTE Energy. Our expertise comes from serving Michigan's electric and natural gas customers for more than 150 years. We never lose sight of their importance to our success.

We were tested in 2004 when regulatory challenges hampered our growth. But we remained focused on regaining the health of our utilities, and made good progress. In 2005, we anticipate that Detroit Edison and MichCon will continue to recover their financial strength and position themselves for future growth. Long term, we expect to generate 70 percent of DTE Energy earnings from regulated operations.



To make this happen we must:

- Aggressively pursue the business we've lost to Michigan's Electric Choice program and seek new business.
- Continue to reduce costs through operating efficiencies.
- Be proactive in managing the regulatory process.

The world of competition has reminded us of the importance of serving our customers well. Our goal is to understand and anticipate their needs and continue to meet and exceed their expectations.

At the same time we grow our customer base, we must shrink costs. The DTE Energy Operating System is a powerful tool we're using to do just that. It's a standardized approach to business, focused on reducing waste, improving processes and cutting costs.

Little improvements can make a big difference, according to Bob Blumer, an electrician who fixes transformers at the Warren Service Center electrical shop. "Because of the changes we've made through the Operating System," he says, "I control my own destiny."

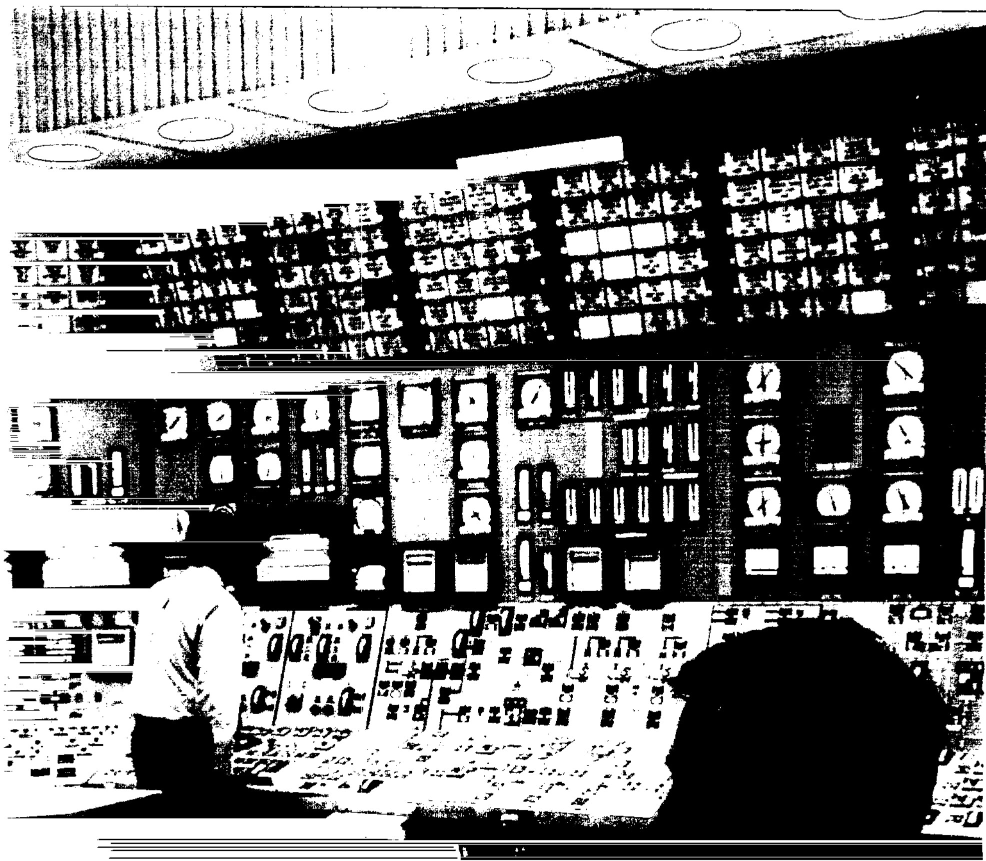
Fixing these transformers used to take more than a month when they arrived at the 51-acre service center. Recognizing that was unacceptable, a team of union and management employees used Operating System tools to study the repair process. They discovered each transformer traveled five miles within the facility during repair and, once fixed, took an additional 10 days for painting and drying.

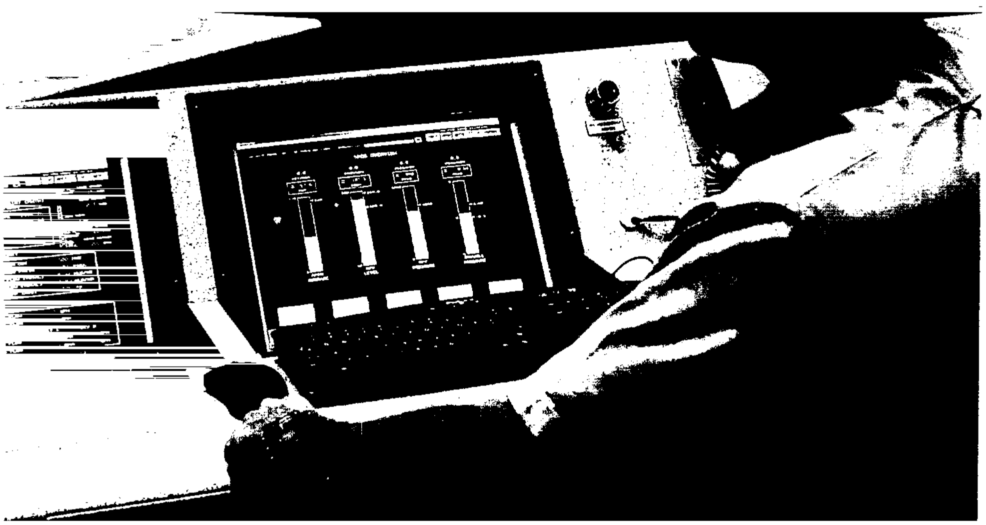
From top: Detroit Edison substation; Marcia Jackson, DTE Energy Operating System expert; MichCon's Petosky gate station; Brian Dantas, environmental engineer.

real people

Warren Service Center Pipe Bending Shop

From left, Robert Swain and Greg Langley





Fermi 2 Nuclear Power Plant

Simone (sitting) and Dave K. Hemmele

Armed with this knowledge, the team created standard work instructions for repairs, including the use of quick-drying paint. These changes eliminated four miles of travel and saved the company an estimated $500,000 in the transformer area alone. Best of all, repairs are now completed in just eight hours. Combined with other Operating System initiatives, the Warren Service Center identified savings exceeding $1.3 million in 2004.

The ultimate goal of the DTE Energy Operating System is to raise performance to a new level and foster a culture of change as a way to improve and learn. Les Click, electrical shop leader says, "The union saw that the Operating System was a business opportunity and took the risk, and you know what? Most people are happier now because they know what's expected; they aren't as stressed out."

Carrying off a complicated refueling outage safely was a team effort at our Fermi 2 nuclear power plant. Thanks to the Operating System, the plant completed its last outage in 27 days, beating its previous record by an impressive six days. "Clearly, using tools of the Operating System helped us complete the outage safely, cost effectively and in record time," says Bill O'Connor, vice president of nuclear generation. In 2004, Fermi 2 was awarded the state's highest safety recognition, the Michigan Voluntary Protection Program Star Award.

Employees at the Broadway Station, a MichCon facility, used the Operating System to substantially increase their productivity. With the lowest field service productivity of all our Detroit area service centers, the Broadway Station assessed, analyzed and improved the situation by implementing tools of the Operating System. Going from worst to first in performance, today the Broadway Station is number one in productivity.

Our goal is to establish a multi-year regulatory strategy that addresses current and future concerns.

Cost savings and increased productivity are just two of the benefits of the Operating System. It's also helping us:

- Reduce injuries.
- Reduce absenteeism.
- Reduce power plant emissions.
- Speed up the hiring process.
- Improve customer restoration times.
- Reduce customer complaints.

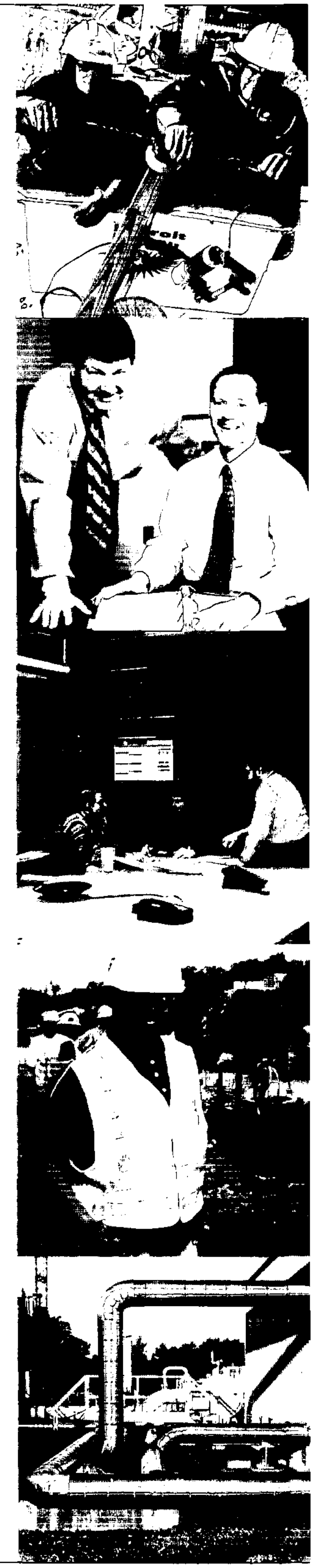
We're proud of our successes, but recognize there are still many opportunities to improve. In 2005, we'll drive the Operating System even deeper into our organization with a goal to identify savings of at least $125 million.

While the DTE Energy Operating System is focused internally, we're focused externally on improving the regulatory environment for our utilities. Our goal is to establish a multi-year regulatory strategy that addresses current concerns and anticipates future needs based on the changing marketplace.

In the long term, we'll continue to build stable structures in the regulatory arena, and develop understanding and support for key energy policy issues before they reach the crisis stage. In the short term, we'll tackle several issues that will significantly impact the performance of our utilities, such as:

- Reform of Electric Choice.
- Low income energy assistance.
- Unbundling and restructuring electric rates.
- Environmental controls and cost recovery.

In the last few years, rising health care costs, infrastructure costs, bad debt expense and margin loss from Electric Choice outstripped productivity savings at our utilities. But with the resolution of our electric and natural gas rate cases, our goal is to move both Detroit Edison and MichCon to their authorized 11 percent rate of return. We view 2005 as a year of rebuilding for our utilities, with a return to traditional performance levels in 2006.



From top: [illegible] Zoelberger and Vern Aitson; Don Stanczak and Jim Padgett, Regulatory Affairs; DTE Energy [illegible] headquarters; Sabrina Wilson, pipeline integrity project; MichCon compressor station.

investing for growth

non-utility businesses

Deep in the heart of Texas, acres of what is quickly becoming the leading U.S. unconventional gas field, lay untapped. The Barnett shale basin, near Fort Worth, holds the potential for significant profits. That's why we recently leased almost 50,000 acres of land there with test drilling under way.

It's just one example of our growth strategy for non-utility businesses. Our investments follow two broad approaches:

- Niche businesses with limited competition and strong returns, such as Barnett shale, synfuel production, industrial coke and waste coal recovery.
- Lower risk businesses where we can add value, such as on-site energy projects that leverage our operations and management experience.

We focus on value. Not size and scope. By remaining true to this philosophy, our non-utility businesses grew substantially for the eighth consecutive year. And we expect net income from these businesses to increase approximately 30 percent in 2005.

Our strategy is to grow in areas closely linked to our utilities, both in the type of business and in the skills they require. Our entry into the Barnett shale, for example, builds on our many years of experience with Antrim shale production. DTE Energy is the second largest operator of Antrim gas wells in Michigan, managing approximately 1,400 Antrim shale wells that produce 22 Bcf a year. Our strong technical and operating expertise allows us to keep expenses down and remain one of the lowest cost operators in the state.

When we evaluate potential investments, we look for a fit in one of three areas:

- Power and industrial projects, such as on-site energy and steel-related projects, power generation and waste coal recovery;
- Unconventional gas production, such as shale and landfill gas production;
- Fuel transportation and marketing, such as coal services, gas pipelines and storage, and energy marketing and trading.

We have an impressive track record in these areas, particularly with on-site energy services. We operate 19 major sites for heavy energy users in the automotive, steel, pulp and paper, and commercial and institutional sectors. This includes nine sites added to our portfolio in 2004.

From top: Rail maintenance and repair facility, Hastings, N.C.; Mark Oliger, biomass site, Witchita, Kan.; synfuel facility, Moundsville, W.Va.; Glen James, on-site energy services, Sparrows Point, Md.

Test drilling in the Barnett shale

From left, James Russell, James Frame and Mike Luster

Energy center at Jeep assembly plant, Toledo, Ohio
From left, Paul Gohl, utility services manager, and John Burgan, energy conservation specialist.

One of our newest transactions is a 20-year contract with DaimlerChrysler to provide utility service at eight sites in Michigan, Ohio and Indiana. Also new in 2004 was our entry into the pulp and paper sector, with an agreement to provide steam and electricity for a tissue mill in Mobile, Ala. In addition, we're now constructing a facility to supply multiple paper mills with pulverized solid fuel.

The next few years present incredible investment opportunities across our portfolio of non-utility businesses.

Our steel-related businesses are also growing. We're the second largest merchant producer of blast furnace coke, a coal derivative used to produce steel. We own 22 percent of independent blast furnace coke production in North America, with the potential to increase our share substantially in the next few years.

Building on our expertise around coal, we began operating our first waste coal recovery plant in 2004. Using proprietary technology, we're turning coal slurry from waste ponds into a quality of coal almost as good as that produced from the original mine. We're refining this process, and believe there's great potential in this untapped market.

Leveraging our knowledge and experience in power plant operations, in 2004 we began providing services to financial institutions that control distressed power generation assets.

We currently manage and operate two plants, one in Connecticut and one in California, that produce 1,800 MW of electricity. We have no equity in these projects, but earn a fee for the service we provide.

Our strong reputation in delivering on-site services, combined with our expertise in coal, is leading to other opportunities in power generation. For example, we're developing a 200-MW coal-fired power plant for an international mining company with operations in the western U.S. We will look for similar ventures with other companies.

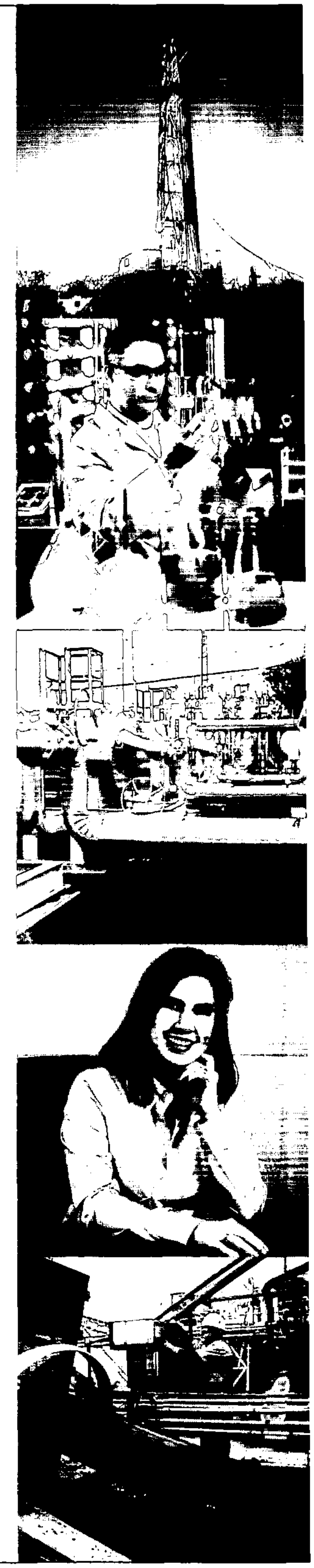
Our existing gas pipelines and storage business also offers growth potential. We own 40 percent of the Vector pipeline, a 348-mile interstate pipeline supplying natural gas from Chicago to Dawn, Ontario. The pipeline, which is operating at full capacity, runs through the heart of MichCon's service territory and gas storage fields. Because demand in the region is very healthy, the expansion of Vector is likely, as is the expansion of our Michigan storage fields.

We also own 10.5 percent of the proposed Millennium pipeline that will run from western New York to New York City. We view Millennium as a potential vehicle to move gas out of storage in Michigan and into markets in New York City and throughout the Northeast.

As we grow, we will continue to follow our disciplined risk management strategy.

The next few years present incredible investment opportunities across our portfolio of non-utility businesses, thanks to the excess cash we expect from our synfuel businesses. (You read about this in the Chairman's letter.) As we grow, we plan to continue following our disciplined risk management strategy. We do not intend to grow at the expense of our balance sheet. We do plan to seek quality investments with returns that exceed our cost of capital. And we plan to focus on opportunities closely linked to our core businesses.

Over the past eight years, we have built an excellent track record of successful investments. We are determined to sustain it.



From top: Test drilling in the Barnett shale; Matthew Korzelius, on-site energy services, Tonawanda, N.Y.; Lake Road Power Plant, Dayville, Conn.; Stephanie Dorian, DTE Energy Services; Marty Campbell, PepTec waste coal recovery.

board of directors

From left, Howard Sims, Eugene Miller, Allan Gilmour, Frank Hennessey, Lillian Bauder and Charles Pryor.
Seated from the left, Gail McGovern, Alfred Glancy, John Lobbia, Josue Robles and Tony Earley.

[illegible], 65, has been vice president of Masco Corporation, since January 2005. From 1996 to 2005, she was vice president of Corporate Affairs, Masco Corporation; she was chairman and president of the Masco Corporation Foundation from 2002 to 2005, and served as the Foundation's president from 1996 to 2001. She was elected to the DTE Energy Board in 1986. (A,E,N,P)

[illegible], 55, has been chairman, chief executive officer and chief operating officer of DTE Energy since 1998 and was president and chief operating officer from 1994 to 2004. He joined DTE Energy in 1994 as its president and chief operating officer, the same year he was elected to the DTE Energy Board. (E)

[illegible], 70, is the retired vice chairman of Ford Motor Company. He served as vice chairman of Ford Motor Company from [illegible] to 1995, and then again from 2002 to February 2005. He was elected to the DTE Energy Board in 1995. (C,E,F,O,S)

[illegible], 66, has been the director of Unico Investment Company since 1974 and its chairman since 2000. He is also the retired chairman and chief executive officer of MCN Energy Group Inc., serving in that position from 1988 through 2001. He joined the DTE Energy Board in 2001. (F,P)

[illegible], 66, has been the chairman and chief executive officer of Hennessey Capital LLC since 2002. Prior to that, Mr. Hennessey was the chairman of Emco Limited from 1995 to 2003; and vice chairman and chief executive officer of MascoTech Inc. from 1998 to 2000. He joined the DTE Energy Board in 2001. (A,P)

[illegible], 63, is the retired chairman and chief executive officer of DTE Energy. He retired in 1998. He joined the company in 1965 and has served on the DTE Energy Board since 1988. (F,N)

[illegible], 53, has been a professor at Harvard Business School since 2002. Prior to that, she was president of Fidelity Personal Investments from 1998 to 2002. She was elected to the DTE Energy Board in 2003. (F)

[illegible], 67, is the retired chairman, president and chief executive officer of Comerica Inc. and Comerica Bank. He retired in 2002. He joined the DTE Energy Board in 1989. (C,E,F,O)

[illegible], 60, has been the president and chief executive officer of Urenco Inc. since 2003. Prior to that, he was the chief executive officer of Utility Services Business Group of BNFL, which includes the Westinghouse Electric Company, from 1997 to 2003. Mr. Pryor joined the DTE Energy Board in 1999. (N)

[illegible], 59, has been the executive vice president, chief financial officer and corporate treasurer of the United Services Automobile Association since 1994. Prior to that, he spent 28 years in the military during which he served as the U.S. Army's budget director at the Pentagon. He was elected to the DTE Energy Board in 2003. (A)

[illegible], 71, is the chairman and chief executive officer of the Sims Design Group Inc. He had served on the board of MCN Energy since 1988 and joined the DTE Energy Board in 2001. (C,N)

Committee membership: A-Audit, C-Corporate Governance, E-Executive (disbanded in November 2004), F-Finance, N-Nuclear Review, O-Organization and Compensation, P-Public Responsibility, S-Special Committee on Compensation (disbanded in April 2004)

executive committee*

DTE Energy leadership

Anthony F. Earley Jr., 55, is chairman, chief executive officer and chief operating officer (COO) of DTE Energy. He joined the company in 1994 as president and COO and that same year was elected a director. He was elected to his current position in 1998. Before joining DTE Energy, Earley served as president and COO of Long Island Lighting Company where he had worked since 1985.

Gerard M. Anderson, 46, is president of DTE Energy and group president of DTE Energy Resources. He was named to his present position in 2004 after serving four years as president of Energy Resources. Previously he was executive vice president of DTE Energy. Anderson joined the company in 1993 from McKinsey & Co., where he was a consultant in energy and finance.

David E. Meador, 47, is executive vice president and chief financial officer (CFO). He joined DTE Energy in 1997 as vice president and controller and was elected senior vice president and CFO in 2001. In 2004 he was elected to his current position. In addition to controller, Meador served as senior vice president and treasurer. Prior to joining DTE Energy, he served in a variety of financial and accounting positions at Chrysler Corp. for 14 years, and was an auditor with Coopers & Lybrand.

Susan M. Beale, 56, is vice president and corporate secretary. She joined the company, as an attorney, in 1982. Beale was named corporate secretary in 1989 and was elected vice president in 1995. She came to DTE Energy after four years with the legal staff of Southern California Edison and two years with Consumers Power.

Ron A. May, 53, is senior vice president of DTE2. He joined the company in 1984 as director of planning and control of nuclear administration. He held a series of increasingly responsible positions, including manager of service center operations; assistant vice president, energy delivery; and vice president energy distribution. He was named to his current position in 2003.

Robert J. Buckler, 55, is group president of DTE Energy Distribution. He joined the company in 1974 and was named to his current post in 1998. He has held numerous positions throughout the organization including power plant engineering, construction and operation, fuel supply management, transmission and distribution operation, customer service, marketing and strategic planning.

Bruce Peterson, 48, is senior vice president and general counsel. Prior to joining DTE Energy in 2003, he was a partner in the Washington, D.C. office of Hunton & Williams, a national law firm specializing in energy industry matters. He spent 14 years with the firm, focusing on energy and infrastructure project finance transactions, acquisitions and divestitures, and related contract structuring and regulatory matters.

Stephen E. Ewing, 60, is group president of DTE Energy Gas. He joined the company in 2001 from MCN Energy, where he served as its president and chief operating officer, and president and chief executive officer of its primary subsidiary, MichCon. Ewing joined MichCon in 1971, holding executive positions in corporate planning, personnel, administration and customer service.

S. Martin Taylor, 64, is executive vice president of Human Resources and Corporate Affairs. He joined the company in 1989 as vice president of corporate and public affairs after serving as president of New Detroit Inc., the first and largest urban coalition in the country. Earlier in his career, he worked as a corporate attorney in Chicago, and then served on the cabinets of two former Michigan governors.

* For more information on other DTE Energy officers, go to dteenergy.com/investors.

chief financial officer's letter

real possibilities

Executive Vice President
and Chief Financial Officer
Dave Meador

I believe we have turned the corner. With our electric and natural gas rate cases behind us, we expect the financial health of our two utilities to improve considerably in 2005. We anticipate cash flows will improve dramatically, providing significant financial flexibility. And we plan to continue to grow our non-utility businesses.

You've already read about our opportunity to reinvest approximately $1.65 billion in cash, expected primarily from synfuel over the next four years. Included in the total is an additional $400 million from growth of our other non-utility businesses.

As we evaluate our options for redeploying this cash, we will seek investments that create value and are consistent with our strategy. At the same time, we will remain disciplined. We plan to build on our company's unique strengths and pursue closely related business lines.

Our plans include investing where the competition is manageable, while focusing on cash flow first, scale second. The objective is to test business proposals with limited capital before making significant investments. And if we can't find opportunities that meet our stringent criteria, we intend to return the cash to our shareholders through stock repurchases.

We are proud of our track record of delivering shareholder value. The long-term success of our company can be attributed to a solid strategy from which we do not waver.

Likewise, our financial objectives have remained constant:

- Focus on value creation (achieve returns that exceed our cost of capital).
- Maintain a strong balance sheet and solid investment grade rating.
- Generate future earnings growth.
- Maintain our dividend at $2.06 per share while our utilities improve their health.
- Continue to communicate openly and transparently about our performance.

Remaining true to these objectives has helped us yield strong performance for our shareholders over the last five and 10 years. The exception was 2004, when uncertainty surrounding Detroit Edison's electric rate case slowed our momentum. Despite this challenge, we maintained the growth of our non-utility businesses as we focused on rebuilding our utilities.

I am deeply committed to achieving our financial objectives. I do not intend to let you down.

David E. Meador

David E. Meador
Executive Vice President and Chief Financial Officer

Above: DTE Energy Headquarters, Detroit, Mich.

management's discussion and analysis
of financial condition and results of operations

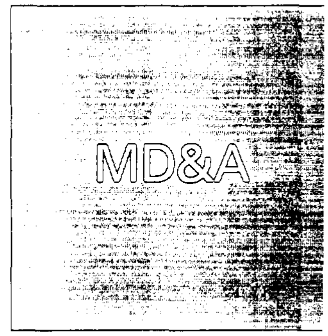
OVERVIEW

DTE Energy is a diversified energy company with approximately $7 billion in revenues in 2004 and approximately $21 billion in assets at December 31, 2004. We are the parent company of Detroit Edison and MichCon, regulated electric and gas utilities engaged primarily in the business of providing electricity and natural gas sales and distribution services throughout southeastern Michigan. Additionally, we have numerous non-utility subsidiaries involved in energy-related businesses predominantly in the Midwest and eastern U.S.

A significant portion of our earnings is derived from our utility operations, synthetic fuel business, and energy marketing and trading operations. Earnings in 2004 were $431 million, or $2.49 per diluted share, down from 2003 earnings of $521 million, or $3.09 per diluted share. As discussed in the "RESULTS OF OPERATIONS" section that follows, the comparability of earnings was impacted by discontinued businesses and the adoption of new accounting rules. Excluding discontinued operations and the cumulative effect of accounting changes, earnings from continuing operations in 2004 were $443 million, or $2.55 per diluted share, compared to earnings of $480 million, or $2.85 per diluted share for the same 2003 period. Income reflects reduced contributions from our utility operations, partially offset by increased contributions from our non-utility businesses and Corporate & Other. Significant items that influenced our 2004 financial performance and/or may affect future results are:

- Electric Customer Choice penetration;
- Electric and gas rate orders;
- Higher operating costs;
- Weather;
- Synfuel-related earnings and the risk of higher oil prices; and
- Growth of non-utility businesses.

Electric Customer Choice Program – Since 2002, Michigan residents and businesses have had the option of participating in the electric Customer Choice program. This program is designed to give all customers added choices and the opportunity to benefit from lower power costs resulting from competition. However, Detroit Edison's rates are regulated by the Michigan Public Service Commission (MPSC), while alternative suppliers can charge market-based rates. This regulation has hindered Detroit Edison's ability to retain customers. In addition, the MPSC has maintained regulated rates for certain groups of customers that exceed the cost of service to those customers. This has resulted in high levels of participation in the electric Customer Choice program by those customers that have the highest rates relative to their cost of service, primarily commercial and industrial businesses. As a result, our margins continue to be affected. To address this issue, we filed a revenue neutral rate restructuring proposal in February 2005 designed to adjust rates for each customer class to be reflective of the full costs incurred to service such customers. Under the proposal, Detroit Edison's commercial and industrial rates would be lowered in 2006, but residential rates would increase over a five-year period beginning in 2007. The number and mix of customers participating in the electric Customer Choice program could be impacted under the rate restructuring.



Lost margins and electricity volumes associated with electric Customer Choice were approximately $237 million and 9,245 gigawatthours (gWh) in 2004. This compares with lost electric Customer Choice margins and volumes of approximately $120 million and 6,193 gWh in 2003. The financial impact of electric Customer Choice was affected by the issuance of electric interim and final rate orders that increased base rates, authorized transition charges and reaffirmed the resumption of the Power Supply Cost Recovery (PSCR) mechanism, as subsequently discussed. Partially offsetting the impact of lost margins on income, we recorded regulatory assets representing stranded costs that we believe are recoverable under existing Michigan legislation and MPSC orders. There are a number of variables and estimates that impact the level of recoverable stranded costs, including weather, sales mix and transition charges. As a result, our estimate of stranded costs could increase or decrease. As subsequently discussed, the MPSC authorized the recovery of $44 million in stranded costs for the period of January 2002 through February 2004.

Detroit Edison rate orders, along with the rate restructuring proposal, address certain issues with the electric Customer Choice program. However, current regulation continues to hinder our ability to retain certain customers. Accordingly, we will continue working with the MPSC and Michigan legislature to address other issues associated with the electric Customer Choice program.

Electric Rate Orders – In 2000, Public Act (PA) 141 froze electric rates for all residential, commercial and industrial customers through 2003. The legislation also prevented rate increases (or capped rates) for small commercial and industrial customers through 2004 and for residential customers through 2005. The rate freeze and caps apply to base rates as well as rates designed to recover fuel and purchased power costs which has traditionally been a cost pass-through under the Power Supply Cost Recovery (PSCR) mechanism.

In 2004, the MPSC issued interim and final rate orders that authorized electric rate increases totaling $374 million, and eliminated transition credits and implemented transition charges for electric Customer Choice customers. The increases were applicable to all customers not subject to a rate cap. The interim order affirmed the resumption of the PSCR mechanism for both capped and uncapped customers, which reduced PSCR revenues by $115 million in 2004. However, the order allowed Detroit Edison to increase base rates for customers still subject to a cap in an equal and offsetting amount to the change in the PSCR factor to maintain the total capped rate levels in effect for these customers. The MPSC also authorized the recovery of approximately $385 million in regulatory assets, including stranded costs.

As a result of rate caps, regulatory asset adjustments and other factors, the rate orders decreased 2004 earnings by $15 million. The impact of the rate orders is expected to increase earnings in 2005 and 2006 as rate caps expire.

Effect of Interim and Final Rate Orders

(in Millions)		2004
Base Rate Increase and Transition Charges	$	154
PSCR Reduction		(115)
Regulatory Assets		
Stranded costs adjustment		(33)
Regulatory asset deferrals – cessation (1)		(29)
Pre-Tax Income (Decrease)	$	(23)
Net Income (Decrease)	$	(15)

(1) We ceased recording regulatory assets for costs that are reflected in rates pursuant to the MPSC's 2004 rate orders.

See Note 4 for a further discussion of the MPSC's interim and final rate orders.

Gas Interim Rate Order – In September 2003, MichCon filed an application with the MPSC for an increase in service and distribution charges (base rates) for its gas sales and transportation customers. The filing requested an overall increase in base rates of $194 million annually (approximately 7% increase, inclusive of gas costs), beginning January 1, 2005. In September 2004, MichCon received an interim order in this rate case authorizing an increase in base rates of $35 million annually, effective September 22, 2004. The interim rate order increased earnings by approximately $6 million in 2004. MichCon expects a final order from the MPSC in the first quarter of 2005.

Operating Costs – During 2004, we experienced increases in operation and maintenance costs, primarily within our electric and gas utilities. The increases were driven by higher costs associated with pension and postretirement benefits and uncollectible accounts receivable.

Pension and postretirement benefits expense totaled $212 million in 2004, compared to $172 million in 2003. The increase is due to financial market performance, lower discount rates and increased health care trend rates. We have made modifications to the pension and postretirement benefit plans to mitigate the earnings impact of higher costs. Additionally, the recoverability of pension and health care benefits costs were part of our electric and gas rate filings. The MPSC approved a pension tracking mechanism in Detroit Edison's final rate order that provides for the recovery or refunding of pension costs above or below the amount reflected in base rates. The MPSC also required Detroit Edison to propose a similar tracking mechanism for retiree health care costs. Detroit Edison filed a request with the MPSC in February 2005 seeking authority to implement a tracking mechanism for retiree health care costs.

Both utilities continue to experience high levels of past due receivables, especially within our Energy Gas operations. The increase is attributable to economic conditions, high natural gas prices and the lack of adequate levels of assistance for low-income customers. As a result of these factors, our allowance for doubtful accounts expense for the two utilities increased to $105 million in 2004 compared to $76 million for the corresponding 2003 period. We are taking aggressive actions to reduce the level of past due receivables, including customer disconnections, contracting with collection agencies and working with the State of Michigan and others to increase the share of low-income funding allocated to our customers.

In MichCon's current gas rate filing, we addressed numerous operating cost issues, including uncollectible accounts receivable expense. The MPSC Staff supports a provision proposed by MichCon that would allow MichCon to recover or refund 90% of uncollectible accounts receivable expense above or below the amount that is reflected in base rates. We support the MPSC Staff's recommendation and believe the provision would significantly reduce our risk of high uncollectible gas accounts receivable.

To partially address this issue of rising costs, we continue to employ the DTE Energy Operating System, which is the application of tools and practices to obtain operating efficiencies and enhance operating performance. We are targeting over $100 million in savings during 2005 through the application of Operating System principles.

Weather – Earnings in our electric and gas utilities are seasonal and sensitive to weather. Electric utility earnings are dependent on hot summer weather, while the gas utility's results are driven by cold winter weather. We experienced both milder summer and winter weather during 2004, which negatively impacted sales demand. The lower demand reduced current year earnings by $27 million compared to 2003.

Additionally, we occasionally experience various types of storms that damage our electric distribution infrastructure resulting in power outages. The impact of storms on our current year earnings was significantly lower than in 2003, which was affected by several catastrophic wind and ice storms, as well as by the August 2003 blackout. Restoration and other costs associated with storm-related power outages lowered 2004 pretax earnings by $48 million compared to $72 million in 2003.

Synthetic Fuel Operations – We operate nine synthetic fuel production plants at eight locations. Since 2002, we have sold majority interests in eight of the nine plants, representing approximately 92% of our total production capacity. Synfuel facilities chemically change coal, including waste and marginal coal, into a synthetic fuel as determined under applicable Internal Revenue Service (IRS) rules. Section 29 of the Internal Revenue Code provides tax credits for the production and sale of solid synthetic fuel produced from coal. Synfuel-related tax credits expire in December 2007.

Operating expenses associated with synfuel projects exceed operating revenues and therefore generate operating losses, which have been more than offset by the resulting Section 29 tax credits. In order to recognize Section 29 tax credits, a taxpayer must have sufficient taxable income in the year the tax credit is generated. Once earned, the tax credits are utilized subject to certain limitations but can be carried forward indefinitely. We have not had sufficient taxable income to fully utilize tax credits earned in prior periods. As of December 2004, we had $483 million in tax credit carry-forwards. In order to optimize income and cash flow from our synfuel operations, we have sold majority interests in eight of our nine facilities and intend to sell a majority interest in the remaining plant during 2005, representing 99% of our production capacity. When we sell an interest in a synfuel project, we recognize the gain from such sale as the facility produces and sells synfuel and when there is persuasive evidence that the sales proceeds have become fixed or determinable and collectability is reasonably assured. Gain recognition is dependent on the synfuel production qualifying for Section 29 tax credits and the value of such credits as subsequently discussed. In substance, we are receiving synfuel gains and reduced operating losses in exchange for tax credits associated with the projects sold. Sales of interests in synfuel projects allow us to accelerate cash flow while maintaining a stable income base.

The value of a Section 29 tax credit can vary each year and is adjusted annually by an inflation factor as published by the IRS in April of the following year. Additionally, the value of the tax credit in a given year is reduced if the "Reference Price" of oil within the year exceeds a threshold price and is eliminated entirely if the Reference Price exceeds a phase-out price. The Reference Price of a barrel of oil is an estimate of the annual average wellhead price per barrel for domestic crude oil, which in recent years has been $3 - $4 lower than the New York Mercantile Exchange (NYMEX) price for light, sweet crude oil. The actual or estimated Reference Price and beginning and ending phase-out prices per barrel of oil for 2003, 2004 and 2005 are as follows:

	Reference Price	Beginning Phase-Out Price	Ending Phase-Out Price
2003 (actual)	$27.56	$50.14	$62.94
2004 (estimated)	$37.61	$51.34	$64.45
2005 (estimated)	Not Available	$52.37	$65.74

Numerous recent events have significantly increased domestic crude oil prices, including terrorism, storm-related supply disruptions and strong worldwide demand. As of February 1, 2005, the NYMEX closing price of a barrel of oil to be delivered in March 2005 was $47.12, which is comparable to a $43.47 Reference Price (assuming that such price was to continue for an entire year). For 2005 and later years, if the Reference Price falls within or exceeds the phase-out range, the availability of tax credits in that year would be reduced or eliminated, respectively.

As previously discussed, until the gain recognition criteria is met, gains from selling interests in synfuel facilities will be deferred. It is possible that gains will be deferred in the first, second and/or third quarters of each year until there is persuasive evidence that no tax credit phase out will occur for the applicable calendar year. This could result in shifting earnings from earlier quarters to later quarters of a calendar year.

As discussed in Notes 12 and 13, we have entered into derivative and other contracts to economically hedge approximately 65% of our 2005 synfuel cash flow exposure related to the risk of an increase in oil prices. We are continuing to evaluate the current volatility in oil prices and alternatives available to mitigate our unhedged exposure to oil prices as part of our synfuel-related risk management strategy.

Assuming no synfuel tax credit phase out in future years, we expect cash flow from our synfuel business to total approximately $1.6 billion between 2005 and 2008. The source of synfuel cash flow includes cash from operations, asset sales, and the utilization of Section 29 tax credits carried forward from synfuel production prior to 2004.

Non-utility Growth – During 2004, we continued to experience growth in our non-utility businesses with income reaching $283 million compared to $256 million in 2003. The improvement primarily reflects increased contributions in our Energy Marketing & Trading segment, primarily due to a one-time contract gain. Additionally, non-utility growth in 2004 is attributable to increased earnings from our synfuels, coke batteries and on-site energy projects. Also affecting the year over year comparison are asset gains, losses and impairments during 2004 and 2003 as subsequently discussed.

Outlook – We made significant progress during the past year on our 2004 corporate priorities, which included:

- Successful rate case outcomes;
- Addressing structural issues with the electric Customer Choice program;
- Continuing sell-down of synfuel portfolio;
- Continuing non-utility growth momentum; and
- Maintaining cash and balance sheet strength.

Our long-term strategy has not changed and in 2005 we will focus on maintaining a strong utility base, pursuing a unique growth strategy focused on value creation in targeted markets, maintaining a strong balance sheet and paying an attractive dividend. The impact of the rate orders is expected to increase utility earnings in 2005 and 2006 as rate caps expire.

Our financial performance will be dependent on successfully redeploying an expected $1.65 billion of cash flow through 2008, primarily associated with proceeds from the sale of interests in synfuel facilities. Our objective for cash redeployment is to strengthen the balance sheet and coverage ratios, as well as replace the value of synfuels that is currently inherent in our share price. We will first use our cash to reduce parent company debt. Secondly, we will continue to pursue growth investments that meet our strict risk-return and value creation criteria. Lastly, share repurchases will be used to build share value if adequate investment opportunities are not available.

RESULTS OF OPERATIONS

We had earnings of $431 million in 2004, or $2.49 per diluted share, compared to earnings of $521 million, or $3.09 per diluted share in 2003 and earnings of $632 million, or $3.83 per diluted share in 2002. As subsequently discussed, the comparability of earnings was impacted by our two discontinued businesses, International Transmission Company and Southern Missouri Gas Company, and the adoption of two new accounting rules in 2003. Excluding discontinued operations and the cumulative effect of accounting changes, our earnings from continuing operations in 2004 were $443 million, or $2.55 per diluted share, compared to earnings of $480 million, or $2.85 per diluted share in 2003 and earnings of $586 million, or $3.55 per diluted share in 2002. The following sections provide a detailed discussion of our segments, operating performance and future outlook.

Segment Performance & Outlook – Through 2004, we operated our businesses through three strategic business units (Energy Resources, Energy Distribution and Energy Gas). Each business unit had utility and non-utility operations. The balance of our business consisted of Corporate & Other. This resulted in the following reportable segments. In 2005, we expect to realign our business units as discussed in Note 1.

(in Millions, except per share data)	2004	2003	2002
Net Income (Loss)			
Energy Resources			
Utility - Power Generation	$ **62**	$ 235	$ 241
Non-utility			
Energy Services	**188**	199	182
Energy Marketing & Trading	**92**	45	25
Other	**1**	(2)	7
Total Non-utility	**281**	242	214
	343	477	455
Energy Distribution			
Utility - Power Distribution	**88**	17	111
Non-utility	**(19)**	(15)	(16)
	69	2	95
Energy Gas			
Utility - Gas Distribution	**20**	29	66
Non-utility	**21**	29	26
	41	58	92
Corporate & Other	**(10)**	(57)	(56)
Income from Continuing Operations			
Utility	**170**	281	418
Non-utility	**283**	256	224
Corporate & Other	**(10)**	(57)	(56)
	443	480	586
Discontinued Operations	**(12)**	68	46
Cumulative Effect of Accounting Changes	**–**	(27)	–
Net Income	$ **431**	$ 521	$ 632
Diluted Earnings Per Share			
Utility	$ **.98**	$ 1.67	$ 2.53
Non-utility	**1.63**	1.52	1.36
Corporate & Other	**(.06)**	(.34)	(.34)
Income from Continuing Operations	**2.55**	2.85	3.55
Discontinued Operations	**(.06)**	.40	.28
Cumulative Effect of Accounting Changes	**–**	(.16)	–
Net Income	$ **2.49**	$ 3.09	$ 3.83

ENERGY RESOURCES

Utility – Power Generation

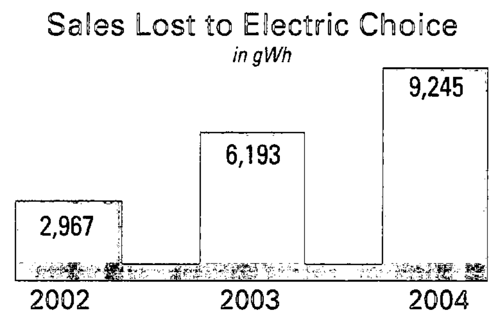
The power generation plants of Detroit Edison comprise our regulated power generation business. Detroit Edison's numerous fossil plants, its hydroelectric pumped storage plant and its nuclear plant generate electricity. The generated electricity, supplemented with purchased power, is sold principally throughout Michigan and the Midwest to residential, commercial, industrial and wholesale customers.

Factors impacting income: Power Generation earnings decreased $173 million in 2004 and $6 million in 2003, compared to the prior year. As subsequently discussed, these results primarily reflect reduced gross margins and increased operation and maintenance expenses.

(in Millions)	2004	2003	2002
Operating Revenues	$ **2,210**	$ 2,448	$ 2,711
Fuel and Purchased Power	**868**	920	1,048
Gross Margin	**1,342**	1,528	1,663
Operation and Maintenance	**672**	628	626
Depreciation and Amortization	**272**	224	331
Taxes Other Than Income	**147**	157	156
Operating Income	**251**	519	550
Other (Income) and Deductions	**166**	149	189
Income Tax Provision	**23**	135	120
Net Income	$ **62**	$ 235	$ 241
Operating Income as a Percent of Operating Revenues	**11 %**	21 %	20 %

Gross margin declined $186 million during 2004 and $135 million in 2003. The declines were due primarily to lost margins from retail customers choosing to purchase power from alternative suppliers under the electric Customer Choice program as well as reduced cooling demand resulting from mild summer weather. As a result of electric Customer Choice penetration, Detroit Edison lost 18% of retail sales in 2004, compared to 12% of such sales during 2003. The loss of retail sales under the electric Customer Choice program also resulted in lower purchase power requirements, as well as excess power capacity that was sold in the wholesale market. Under the 2004 interim and final rate orders previously discussed, revenues from selling excess power reduce the level of recoverable fuel and purchased power costs and therefore do not impact margins associated with uncapped customers. The rate orders also lowered PSCR revenues, which were partially offset by increased base rate and transition charge revenues.

Weather in 2004 was 3% milder than 2003, resulting in lost margins of $25 million. Weather in 2003 was also milder than the prior year, resulting in lost margins of $114 million. The decline in margins and revenues in 2004 was also due to the allocation of a smaller portion of Detroit Edison's billings to Power Generation.



Operating revenues and fuel and purchased power costs decreased in 2004 and 2003 reflecting a $1.27 per megawatt hour (MWh) (8%) decline in fuel and purchased power costs during 2004 and a $.64 per MWh (4%) decline during 2003. Fuel and purchased power costs are a pass-through with the reinstatement of the PSCR in 2004, and therefore do not affect margins or earnings associated with uncapped customers. The decrease in fuel and purchased power costs is attributable to lower priced purchases and the use of a more favorable power supply mix driven by higher generation output. The favorable mix is due to lower purchases, driven by lost sales under the electric Customer Choice program. The comparison was also affected by higher costs associated with substitute power purchased to meet customer demand during the August 2003 blackout. We were required to purchase additional power during the 36-day period it took for our generation fleet to return to pre-blackout capacity.

(in Thousands of MWh)	2004	2003	2002
Electric Sales and Use			
Retail	**40,379**	43,672	48,346
Wholesale and Other	**8,569**	5,600	6,128
	48,948	49,272	54,474
Internal Use and Line Loss	**3,574**	3,248	3,651
	52,522	52,520	58,125

(in Thousands of MWh)	2004		2003		2002	
Power Generated and Purchased						
Power Plant Generation						
Fossil	**39,432**	**75 %**	38,052	72 %	39,017	67 %
Nuclear (Fermi 2)	**8,440**	**16**	8,114	16	9,301	16
	47,872	**91**	46,166	88	48,318	83
Purchased Power	**4,650**	**9**	6,354	12	9,807	17
System Output	**52,522**	**100 %**	52,520	100 %	58,125	100 %
Average Unit Cost ($/MWh)						
Generation (1)		**$ 12.98**		$ 12.89		$ 12.53
Purchased Power (2)		**$ 37.06**		$ 41.73		$ 39.16
Overall Average Unit Cost		**$ 15.11**		$ 16.38		$ 17.02

(1) Represents fuel costs associated with power plants.

(2) Includes amounts associated with hedging activities.

Operation and maintenance expense increased $44 million in 2004 and $2 million in 2003. The 2004 increase reflects costs associated with maintaining our generation fleet, including costs of scheduled and forced plant outages. Additionally, the increase in 2004 is due to incremental costs associated with the implementation of our DTE2 project, a Company-wide initiative to improve existing processes and to implement new core information systems, including finance, human resources, supply chain and work management. Operation and maintenance expense in both years includes higher employee pension and health care benefit costs due to financial market performance, discount rates and health care trend rates. Expenses in 2003 were also affected by $5 million in costs associated with the August 2003 blackout.

Depreciation and amortization expense increased $48 million in 2004 and decreased $107 million in 2003. The variations reflect the income effect of recording regulatory assets, which lowered depreciation and amortization expenses. The regulatory asset deferrals totaled $107 million in 2004 and $153 million in 2003, representing net stranded costs and other costs we believe are recoverable under PA 141.

Other income and deductions expense increased $17 million in 2004 and decreased $40 million in 2003. The 2004 increase is primarily due to lower income associated with recording a return on regulatory assets, as well as costs associated with addressing the structural issues of PA 141. The 2003 decrease is attributable to lower interest expenses and increased interest income. Interest expense reflects lower borrowing levels and rates, and interest income includes the accrual of carrying charges on environmental-related regulatory assets.

Outlook – Future operating results are expected to vary as a result of external factors such as regulatory proceedings, new legislation, changes in market prices of power, coal and gas, plant performance, changes in economic conditions, weather and the levels of customer participation in the electric Customer Choice program.

As previously discussed, we expect cash flows and operating performance will continue to be at risk due to the electric Customer Choice program until the issues associated with this program are addressed. We will accrue as regulatory assets our unrecovered generation-related fixed costs (stranded costs) due to electric Customer Choice that we believe are recoverable under Michigan legislation and MPSC orders. We have addressed certain issues of the electric Customer Choice program in our February 2005 rate restructuring proposal. We cannot predict the outcome of these matters.

In conjunction with the sale of the transmission assets of ITC in February 2003, the Federal Energy Regulatory Commission (FERC) froze ITC's transmission rates through December 2004. It is expected that annual rate adjustments pursuant to a formulistic pricing mechanism beginning in January 2005 will result in an estimated increase in Detroit Edison's transmission expense of $50 million annually. Additionally, in a proceeding before the FERC, several Midwest utilities seek to recover transmission revenues lost as a result of a FERC order modifying the pricing of transmission service in the Midwest. Detroit Edison estimates that its potential obligation as a result of this proceeding could be $2.2 million per month from December 2004 through March 2005 and $1 million per month from April 2005 through March 2006. Detroit Edison is expected to incur an additional $15 million in 2005 for charges related to the implementation of Midwest Independent Transmission System Operator's open market. As previously discussed, Detroit Edison received rate orders in 2004 that allow for the recovery of increased transmission expenses through the PSCR mechanism. See Note 4 – Regulatory Matters.

Energy Services

Energy Services is comprised of Coal-Based Fuels, On-Site Energy Projects and non-utility Power Generation. Coal-Based Fuels operations include producing synthetic fuel from nine synfuel plants and producing coke from three coke battery plants. The production of synthetic fuel from all of our synfuel plants and the production of coke from one of our coke batteries generate tax credits under Section 29 of the Internal Revenue Code. On-Site Energy Projects include pulverized coal injection, power generation, steam production, chilled water production, wastewater treatment and compressed air supply. Power Generation owns and operates four gas-fired peaking electric generating plants and manages and operates two additional gas-fired power plants under contract. Additionally, Power Generation develops, operates and acquires coal and gas-fired generation.

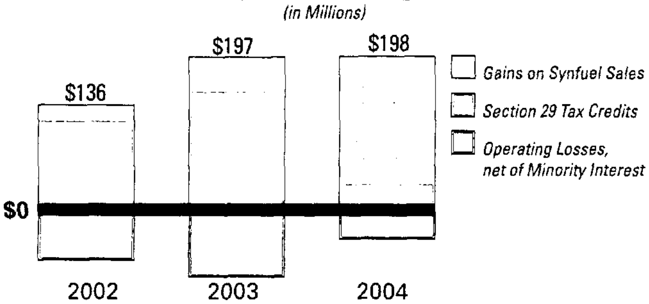
Factors impacting income: Energy Services earnings decreased $11 million in 2004 and increased $17 million in 2003, compared to the prior year. As subsequently discussed, these results primarily reflect higher gains recognized from selling majority interests in our synfuel plants, varying levels of Section 29 tax credits, a gain from contract termination, uncollectible accounts written-off and losses on synfuel hedges.

(in Millions)	2004	2003	2002
Operating Revenues			
Coal-Based Fuels	**$ 980**	$ 850	$ 559
On-Site Energy Projects	**96**	70	63
Power Generation – Non-utility	**13**	9	23
	1,089	929	645
Operation and Maintenance	**1,188**	1,049	708
Depreciation and Amortization	**82**	84	81
Taxes other than Income	**15**	18	15
Gain on Sale of Interests in Synfuel Projects	**(219)**	(83)	(40)
Operating Income (Loss)	**23**	(139)	(119)
Other (Income) and Deductions	**(17)**	2	4
Minority Interest	**(212)**	(91)	(37)
Income Taxes			
Provision (Benefit)	**95**	(19)	(30)
Section 29 Tax Credits	**(31)**	(230)	(238)
	64	(249)	(268)
Net Income	**$ 188**	$ 199	$ 182

Operating revenues increased $160 million in 2004 and $284 million in 2003 reflecting higher synfuel, coal and coke sales, as well as increased revenues from our on-site energy projects.

The improvement in synfuel revenues results from increased production due to additional sales of project interests in 2004 and 2003, reflecting our strategy to produce synfuel primarily from plants in which we had sold interests in order to optimize income and cash flow. As previously discussed, operating expenses associated with synfuel projects exceed operating revenues and therefore generate operating losses, which have been more than offset by the resulting Section 29 tax credits. When we sell an interest in a synfuel project, we recognize the gain from such sale as the facility produces and sells synfuel and when there is persuasive evidence that the sales proceeds to the Company have become fixed or determinable and collectability is reasonably assured. In substance, we are receiving synfuel gains and reduced operating losses in exchange for tax credits associated with the projects sold.

Synfuel earnings
(in Millions)



Coal marketing revenues in 2004 have also been affected by our strategy to produce synfuel primarily from plants in which we had sold interests. This strategy resulted in the reduction of synfuel production levels. We were contractually obligated to supply coal to customers at certain sites that did not produce synfuel as a result of our current production strategy. To meet our obligations to provide coal under long-term contracts with customers, we acquired coal that was resold to customers. The coal was sold at prices higher than the prices at which synfuel would have been sold to these customers.

Revenues from coke sales were higher in 2004, due to higher coke sales volumes combined with higher market prices, due to limited supplies of coke in the U.S.

Revenues from on-site energy projects increased in 2004, reflecting the completion of new long-term utility services contracts with a large automotive company and a large manufacturer of paper products. Revenues in 2004 include a $9 million pre-tax fee generated in conjunction with the development of a related energy project, 50% of which was sold to an unaffiliated partner.

Operation and maintenance expense increased $139 million in 2004 and $341 million in 2003, reflecting costs associated with synfuel production and coke operations. Partially offsetting the higher synfuel operating costs in 2004 was the recording of insurance proceeds associated with an accident at one of our coke batteries. Operation and maintenance expense in 2003 was affected by a $30 million pre-tax gain from the termination of a tolling agreement at one of our generation facilities, substantially offset by the establishment of a $28 million pre-tax reserve for receivables associated with a large customer that filed for bankruptcy.

Gains on sale of interests in synfuel projects increased $136 million in 2004 and $43 million in 2003. The improvements are due to additional sales of majority interests in our synfuel projects. To hedge our exposure to the risk of an increase in oil prices that could reduce synfuel sales proceeds, we entered into derivative and other contracts covering approximately 65% of our 2005 synfuel cash flow exposure. The derivative contracts are accounted for under the mark to market method with changes in their fair value recorded as an adjustment to synfuel gains. We recorded a mark to market loss during the 2004 fourth quarter, which reduced 2004 synfuel gains by $12 million pre-tax. See Note 12 for further discussion.

Minority interest increased $121 million in 2004 and $54 million in 2003, reflecting our partners' share of operating losses associated with synfuel operations. The sale of interests in our synfuel facilities during 2004 and 2003 resulted in allocating a larger percentage of such losses to our partners.

Income taxes increased $313 million in 2004 and $19 million in 2003, reflecting higher taxable earnings and a decline in the level of Section 29 tax credits due to the sale of interests in synfuel facilities.

Outlook – Energy Services will continue leveraging its extensive energy-related operating experience and project management capability to develop and grow the on-site energy business. We expect solid earnings from our on-site energy business in 2005 as a result of executing long-term utility services contracts in 2004.

Energy Marketing & Trading

Energy Marketing & Trading consists of the electric and gas marketing and trading operations of DTE Energy Trading and CoEnergy. DTE Energy Trading focuses on physical power marketing and structured transactions, as well as the enhancement of returns from DTE Energy's power plants. CoEnergy focuses on physical gas marketing and the optimization of DTE Energy's owned and contracted natural gas pipelines and gas storage capacity. To this end, both companies enter into derivative financial instruments as part of their marketing and hedging strategies, including forwards, futures, swaps and option contracts. Most of the derivative financial instruments are accounted for under the mark to market method, which results in earnings recognition of unrealized gains and losses from changes in the fair value of the derivatives.

Factors impacting income: Energy Marketing & Trading's earnings increased $47 million in 2004, consisting of a $4 million improvement at DTE Energy Trading and a $43 million improvement at CoEnergy. Earnings increased $20 million in 2003, of which $18 million was attributable to DTE Energy Trading and $2 million to CoEnergy.

DTE Energy Trading's earnings improvement in 2004 and 2003 was primarily due to realized margins associated with short-term physical trading and origination activities.

(in Millions)	2004	2003	2002
DTE Energy Trading			
Margins – Gains (Losses)			
Realized (1)	$ 83	$ 82	$ 38
Unrealized (2):			
Proprietary Trading (3)	(7)	(7)	–
Structured Contracts (4)	3	(2)	13
Economic Hedges (5)	1	–	–
Total Unrealized Margins	(3)	(9)	13
Total Margins	80	73	51
Operating and Other Costs	29	28	29
Income Tax Provision	15	13	8
Net Income	$ 36	$ 32	$ 14
CoEnergy			
Margins – Gains (Losses) (7)			
Realized (1)	$ (42)	$ 168	$ 32
Unrealized (2):			
Proprietary Trading (3)	–	4	9
Structured Contracts (4)	(1)	(1)	22
Economic Hedges (5)	68	(138)	(93)
Gas in Inventory (6)	–	–	74
Total Unrealized Margins	67	(135)	12
Total Margins	25	33	44
Gain from Contract Modification/Termination	(74)	–	–
Operating and Other Costs	12	13	27
Income Tax Provision	31	7	6
Net Income	$ 56	$ 13	$ 11
Total Energy Marketing & Trading Net Income	$ 92	$ 45	$ 25

(1) Realized margins include the settlement of all derivative and non-derivative contracts, as well as the amortization of deferred assets and liabilities.

(2) Unrealized margins include mark-to-market gains and losses on derivative contracts, net of gains and losses reclassified to realized. See "Fair Value of Contracts" section that follows.

(3) "Proprietary Trading" represents the net unrealized effect of actively traded positions entered into to take advantage of market price movements.

(4) "Structured Contracts" represent the net unrealized effect of derivative transactions entered into with the intent to capture profits by originating substantially hedged positions with wholesale energy marketers, utilities, retail aggregators and alternative energy suppliers.

(5) "Economic Hedges" represent the net unrealized effect of derivative activity associated with assets owned or contracted for by DTE Energy, including forward sales of gas production and trades associated with transportation and storage capacity.

(6) Gas in inventory margins represent gains associated with fair value accounting in 2002. CoEnergy changed its method of accounting for inventory in January 2003 (Note 2).

(7) Excludes the impact on margins from the modification of a transportation agreement with an interstate pipeline company.

CoEnergy's earnings in 2004 and 2003 were affected by varying gains and losses on economic hedge contracts related to storage assets. As subsequently discussed in the *"Outlook"* section, the unrealized gains and losses of economic hedge contracts are required to be recognized under mark-to-market accounting, while the offsetting unrealized losses and gains on the underlying asset positions are not recognized.

CoEnergy's earnings in 2004 reflect a $74 million one-time pre-tax gain from modifying a future purchase commitment under a transportation agreement and terminating a related long-term gas exchange (storage) agreement with an interstate pipeline company. Under the gas exchange agreement, we received gas from the customer during the summer injection period and redelivered the gas during the winter heating season.

The realized and unrealized margins comparison for both DTE Energy Trading and CoEnergy was affected by our decision in late 2003 to monetize certain in-the-money derivative contracts while simultaneously entering into replacement at-the-market contracts. The monetizations were completed in conjunction with implementing a series of initiatives to improve cash flow and fully utilize Section 29 tax credits. Although the monetizations did not impact earnings, they had the effect of decreasing realized margins and increasing unrealized margins on economic hedges in 2004, and having the opposite effect on margins in 2003.

Outlook – Energy Marketing & Trading will seek to manage its business in a manner consistent with, and complementary to, the growth of our other business segments. Gas storage and transportation capacity enhances our ability to provide reliable and custom-tailored bundled services to large-volume end users and utilities. This capacity, coupled with the synergies from DTE Energy's other businesses, positions the segment to add value.

Significant portions of the Energy Marketing & Trading portfolio are economically hedged. The portfolio includes financial instruments and gas inventory, as well as owned and contracted natural gas pipelines and storage assets. The financial instruments are deemed derivatives, whereas the gas inventory, pipelines and storage assets are not considered derivatives for accounting purposes. As a result, Energy Marketing & Trading will experience earnings volatility as derivatives are marked to market without revaluing the underlying non-derivative contracts and assets. The majority of such earnings volatility is associated with the natural gas storage cycle, which runs annually from April of one year to March of the next year. Our strategy is to economically hedge the price risk of all gas purchases for storage with sales in the over-the-counter (forwards) and futures markets. Current accounting rules require the marking to market of forward sales and futures, but do not allow for the marking to market of the related gas inventory. This results in gains and losses that are recognized in different interim and annual accounting periods. We anticipate the financial impact of this timing difference will reverse by the end of each storage cycle. See "Fair Value of Contracts" section that follows.

Non-utility – Other

Our other non-utility businesses include our Coal Services and Biomass units. Coal Services provides fuel, transportation and rail equipment management services. We specialize in minimizing fuel costs and maximizing reliability of supply for energy-intensive customers. Additionally, we participate in coal trading and coal-to-power tolling transactions, as well as the purchase and sale of emissions credits. Coal Services has formed a subsidiary, DTE PepTec Inc., which uses proprietary technology to produce high quality coal products from fine coal slurries typically discarded from coal mining operations. Biomass develops, owns and operates landfill recovery systems in the U.S. Gas produced from many of these landfill sites qualifies for Section 29 tax credits.

Factors impacting income: Earnings increased $3 million in 2004 and declined $9 million in 2003. The 2004 increase reflects higher sales from coal and emissions credits, partially offset by increased costs associated with our waste coal operations. The 2003 decline reflects reduced marketing and tolling income as well as an increase in operating costs associated with ramping up the DTE PepTec business. Our first waste coal facility in Ohio became operational in late 2003.

(Dollars in Millions)	2004	2003	2002
Coal Services			
Tons of coal shipped (in millions)	**39.9**	32.0	28.5
Biomass			
Gas Produced (in Bcf)	**23.2**	26.8	27.5
Tax Credits Generated (1)	**$ 7.7**	$ 10.5	$ 12.9

(1) DTE Energy's portion of total tax credits generated.

Outlook – We expect to continue to grow our Coal Services and Biomass units. We believe a substantial market could exist for the use of DTE PepTec Inc. technology and we continue to modify and prove out this technology. Coal Services and Biomass have formed a new subsidiary to enter the coal mine methane business. We purchased coal mine methane assets in Illinois at the end of 2004, and expect to reconfigure equipment and restart operations by mid-2005.

The Section 29 tax credits generated by Biomass are subject to the same phase out risk if domestic crude oil prices reach certain levels, as detailed in the synthetic fuel operations discussion. See Note 13.

ENERGY DISTRIBUTION

Utility - Power Distribution

Power Distribution operations include the electric distribution services of Detroit Edison. Power Distribution distributes electricity generated and purchased by Energy Resources and alternative energy suppliers to Detroit Edison's 2.1 million customers.

Factors impacting income: Power Distribution earnings increased $71 million during 2004 and decreased $94 million in 2003, compared to the prior year. As subsequently discussed, these results primarily reflect varying operating revenues and operation and maintenance expenses, as well as a non-recurring loss recorded in 2003.

(in Millions)	2004	2003	2002
Operating Revenues	**$ 1,358**	$ 1,247	$ 1,343
Fuel and Purchased Power	**17**	19	26
Operation and Maintenance	**723**	724	649
Depreciation and Amortization	**251**	249	246
Taxes Other Than Income	**101**	100	117
Operating Income	**266**	155	305
Other (Income) and Deductions	**137**	128	136
Income Tax Provision	**41**	10	58
Net Income	**$ 88**	$ 17	$ 111
Operating Income as a Percent of Operating Revenues	**20 %**	12 %	23 %

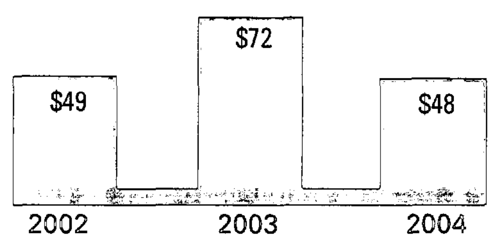
(in Thousands of MWh)	2004	2003	2002
Electric Deliveries			
Residential	**15,081**	15,074	15,958
Commercial	**13,425**	15,942	18,395
Industrial	**11,472**	12,254	13,590
Wholesale	**2,197**	2,241	2,249
Other	**401**	402	403
	42,576	45,913	50,595
Electric Choice	**9,245**	6,193	2,967
Electric Choice – Self Generations*	**595**	1,088	543
Total Electric Deliveries	**52,416**	53,194	54,105

* Represents deliveries for self generators who have purchased power from alternative energy suppliers to supplement their power requirements.

Operating revenues increased $111 million in 2004, primarily due to an increase in base rates resulting from the interim and final rate orders. The 2004 improvement is also attributable to residential sales growth and the allocation of a higher portion of Detroit Edison's billings to Power Distribution, partially offset by the effects of milder weather. Operating revenues decreased $96 million in 2003, reflecting mild summer weather and the impact of slower economic conditions.

Operation and maintenance expense decreased $1 million in 2004 and increased $75 million in 2003. The operation and maintenance expense comparability was affected by 2003 restoration costs associated with three catastrophic storms and the August 2003 blackout. Both years were also affected by an increase in reserves for uncollectible accounts receivable, reflecting high past due amounts attributable to economic conditions, and an increase in employee benefit costs. Additionally, the comparisons were affected by incremental costs associated with our DTE2 project implementation, a $22 million pre-tax loss in 2003 from the sale of our steam heating business, and the accrual of refunds in 2004 and 2003 associated with transmission services.

Storm Restoration Costs
(in Millions)



Outlook – Operating results are expected to vary as a result of external factors such as weather, changes in economic conditions and the severity and frequency of storms.

We experienced numerous catastrophic storms over the past few years. The effect of the storms on annual earnings was partially offset by storm insurance. We have been unable to obtain storm insurance at economical rates and as a result, we do not anticipate having insurance coverage at levels that would significantly offset unplanned expenses from ice storms, tornadoes, or high winds that damage our distribution infrastructure.

Non-Utility

Non-utility Energy Distribution operations consist of DTE Energy Technologies, which assembles, markets, distributes and services distributed generation products, provides application engineering, and monitors and manages on-site generation system operations.

Factors impacting income: Non-utility results declined $4 million in 2004 and improved $1 million in 2003. The 2004 decrease includes an impairment charge for an "other than temporary" decline in the fair value of an investment in a joint venture that supplied certain distributed generation equipment and materials to DTE Energy Technologies.

Outlook – DTE Energy Technologies will focus on sales of proprietary pre-engineered and packaged continuous generation products in key applications. This will likely result in near-term revenue decline, but we anticipate gross profit margins will improve. Combined with continuing cost reductions and resumption of sales growth, we believe these actions will lead to improved financial performance in 2005.

ENERGY GAS

Utility – Gas Distribution

Gas Distribution operations include gas distribution services primarily provided by MichCon, our gas utility that purchases, stores, distributes and sells natural gas to 1.2 million residential, commercial and industrial customers located throughout Michigan.

Factors impacting income: Gas Distribution's earnings declined $9 million in 2004 and $37 million in 2003, compared to the prior year. As subsequently discussed, results primarily reflect varying gross margins, higher operation and maintenance expenses and a non-recurring loss recorded in 2003.

(in Millions)	2004	2003	2002
Operating Revenues	$ **1,682**	$ 1,498	$ 1,369
Cost of Gas	**1,071**	909	774
Gross Margins	**611**	589	595
Operation and Maintenance	**400**	371	297
Depreciation and Amortization	**103**	101	104
Taxes Other Than Income	**49**	52	51
Operating Income	**59**	65	143
Other (Income) and Deductions	**48**	36	41
Income Tax Provision (Benefit)	**(9)**	–	36
Net Income	$ **20**	$ 29	$ 66
Operating Income as a Percent of Operating Revenues	**4 %**	4 %	10 %

Gross margins increased $22 million in 2004 and decreased $6 million in 2003, compared to the prior year. The improvement in 2004 reflects the impact of interim rate relief and additional margin from the acceleration of several midstream services contracts. Partially offsetting these improvements were lower sales and end user transportation deliveries due to milder weather. The gross margin comparison was also affected by a $26.5 million pre-tax reserve recorded in 2003 for the potential disallowance in gas costs pursuant to an MPSC order in MichCon's 2002 gas cost recovery (GCR) plan case (Note 4). Operating revenues and cost of gas increased significantly in 2004 and 2003 reflecting higher gas prices, which are recoverable from customers through the GCR mechanism.

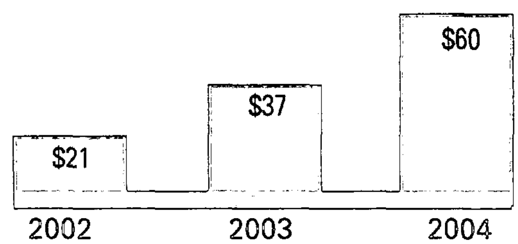
(in Millions)	2004	2003	2002
Gas Markets			
Gas sales	$ **1,435**	$ 1,242	$ 1,135
End user transportation	**119**	136	122
	1,554	1,378	1,257
Intermediate transportation	**56**	51	48
Other	**72**	69	64
	$ **1,682**	$ 1,498	$ 1,369

(in Bcf)	2004	2003	2002
Gas Markets			
Gas sales	**173**	181	174
End user transportation	**145**	152	171
	318	333	345
Intermediate transportation	**536**	576	492
	854	909	837

Operation and maintenance expense increased $29 million in 2004 and $74 million in 2003, reflecting higher reserves for uncollectible accounts receivable and pension and health care costs. The increase in uncollectible accounts expense reflects high past due amounts attributable to an increase in gas prices, continued weak economic conditions and a lack of adequate public assistance for low-income customers.

Uncollectible Accounts Expense

(in Millions)



Other income and deductions expense increased $12 million in 2004 and decreased $5 million in 2003, reflecting a 2003 gain on sale of interests in a series of real estate partnerships.

Income taxes in 2004 and 2003 were impacted by lower earnings and favorably affected by an increase in the amortization of tax benefits previously deferred in accordance with MPSC regulations.

Outlook – Operating results are expected to vary as a result of external factors such as regulatory proceedings, weather and changes in economic conditions. Higher gas prices and economic conditions have resulted in an increase in past due receivables. We believe our allowance for doubtful accounts is based on reasonable estimates. However, failure to make continued progress in collecting past due receivables would unfavorably affect operating results. Energy assistance programs funded by the federal government and the State of Michigan remain critical to MichCon's ability to control uncollectible accounts receivable expenses. We are working with the State of Michigan and others to increase the share of funding allocated to our customers to be representative of the number of low-income individuals in our service territory.

As a result of the continued increase in operating costs, MichCon filed a rate case in September 2003 to increase rates by $194 million annually to address future operating costs and other issues. MichCon received an interim order in this rate case in September 2004 increasing rates by $35 million annually. The MPSC Staff has recommended a provision that would allow MichCon to recover or refund 90% of uncollectible accounts receivable expense above or below the amount that is reflected in base rates. See Note 4 – Regulatory Matters.

Non-utility

Non-utility operations include the Gas Production business and the Gas Storage, Pipelines & Processing business. Our Gas Production business produces gas from proven reserves in northern Michigan and sells the gas to the Energy Marketing & Trading segment. Gas Storage, Pipelines & Processing has a partnership interest in an interstate transmission pipeline, seven carbon dioxide processing facilities and a natural gas storage field, as well as lease rights to another natural gas storage field. The assets of these businesses are well integrated with other DTE Energy entities.

Factors impacting income: Earnings decreased $8 million in 2004 and increased $3 million in 2003. The decline in 2004 is due to gains recorded in 2003 from selling our 16% pipeline interest in the Portland Natural Gas Transmission System, as well as from selling certain gas properties. Excluding those gains, income increased $2 million reflecting the acquisition of an additional 15% ownership in the Vector Pipeline in late 2003, increased sales of transportation capacity by Vector Pipeline and increased storage sales throughout 2004.

Outlook – We anticipate further expansion of our storage facilities and Vector pipeline to take advantage of available growth opportunities. We are also seeking to secure markets for our 10.5% interest in the Millennium Pipeline.

We expect to continue developing our gas production properties in northern Michigan and leverage our experience in this area by pursuing investment opportunities in unconventional gas production outside of Michigan. During 2004, we acquired approximately 50,000 leasehold acres in the southern region of the Barnett shale in Texas, an area of increasing production. We began drilling test wells in December 2004 and anticipate drilling a significant number of additional test wells in the first half of 2005. Initial results from the test wells are expected in mid-2005. If the results are successful, we could commit up to $350 million of capital over the next several years to develop these properties.

CORPORATE & OTHER

Corporate & Other includes various corporate support functions such as accounting, legal and information technology. As these functions essentially support the entire Company, their costs are fully allocated to the various segments based on services utilized and therefore the effect of the allocation on each segment can vary from year to year. Additionally, Corporate & Other holds certain non-utility debt and investments, including assets held for sale and in emerging energy technologies.

Factors impacting income: Corporate & Other results improved $47 million in 2004, compared to a $1 million decline in 2003. The 2004 improvement was affected by a $14 million net of tax gain from the sale of 3.5 million shares of Plug Power stock (Note 1), as well as lower Michigan Single Business Taxes, resulting from tax saving initiatives. Results for 2003 include a $15 million cash contribution to the DTE Energy Foundation, funded with proceeds received from the sale of ITC. Corporate & Other also benefited from lower financing costs and increased intercompany interest income in both periods.

DISCONTINUED OPERATIONS

Southern Missouri Gas Company (SMGC) – We own SMGC, a public utility engaged in the distribution, transmission and sale of natural gas in southern Missouri. In 2004, management approved the marketing of SMGC for sale. Under U.S. generally accepted accounting principles, we classified SMGC as a discontinued operation in 2004 and recognized a net of tax impairment loss of approximately $7 million, representing the write-down to fair value of the assets of SMGC, less costs to sell, and the write-off of allocated goodwill. In November 2004, we entered into a definitive agreement providing for the sale of SMGC. Following receipt of regulatory approvals and resolution of other contingencies, it is anticipated that the transaction will close in 2005.

International Transmission Company – In February 2003, we sold ITC, our electric transmission business, to affiliates of Kohlberg Kravis Roberts & Co. and Trimaran Capital Partners, LLC. Accordingly, we classified ITC as a discontinued operation. The sale generated a preliminary net of tax gain of $63 million in 2003. The gain was net of transaction costs, the portion of the gain that was refundable to customers and the write off of approximately $44 million of allocated goodwill. The gain was lowered to $58 million in 2004 under the MPSC's November 2004 final rate order that resulted in a revision of the applicable transaction costs and customer refund. We had income from discontinued operations of $5 million in 2003.

See Note 3 for further discussion.

CUMULATIVE EFFECT OF ACCOUNTING CHANGES

As required by U.S. generally accepted accounting principles, on January 1, 2003, we adopted new accounting rules for asset retirement obligations and energy trading activities. The cumulative effect of adopting these new accounting rules reduced 2003 earnings by $27 million. See Note 2 for further discussion.

CAPITAL RESOURCES AND LIQUIDITY

DTE Energy and its subsidiaries require cash to operate and cash is provided by both internally and externally generated sources. We manage our liquidity and capital resources to maintain financial flexibility to meet our current and future cash flow needs.

Cash Requirements

We use cash to maintain and expand our electric and gas utilities and to grow our non-utility businesses, in addition to retiring and paying interest on long-term debt and paying dividends. Our strategic direction anticipates base level capital investments and expenditures for existing businesses in 2005 of up to $1.1 billion. The capital needs of our utilities will increase due primarily to environmental related expenditures.

Capital spending for general corporate purposes will increase in 2005, primarily as a result of DTE2 and environmental spending. We began implementing the DTE2 project in 2003. The Company expects the project to incrementally cost approximately $150 million to $175 million.

The EPA ozone transport regulations and final new air quality standards relating to ozone and particulate air pollution will continue to impact us. Detroit Edison estimates that it will spend approximately $100 million in 2005 and incur up to an additional $1.3 billion of future capital expenditures over the next five to eight years to satisfy both existing and proposed new control requirements. The full recovery of $550 million of environmental expenditures was authorized in the MPSC's November 2004 final rate order.

Non-utility capital spending will approximate $100 million to $300 million annually for the next several years. Capital spending for growth of existing or new businesses will depend on the existence of opportunities that meet our strict risk-return and value creation criteria.

Debt maturing in 2005, excluding securitization debt, totals approximately $410 million.

We believe that we will have sufficient internal and external capital resources to fund anticipated capital requirements.

(in Millions)	2004	2003	2002
Cash and Cash Equivalents			
Cash Flow From (Used For)			
Operating activities:			
Net income	$ 431	$ 521	$ 632
Depreciation, depletion and amortization	744	691	759
Deferred income taxes	129	(220)	(208)
Gain on sale of ITC, synfuel and other assets, net	(236)	(228)	(40)
Working capital and other	(73)	186	(147)
	995	950	996
Investing activities:			
Plant and equipment expenditures – utility	(815)	(679)	(794)
Plant and equipment expenditures – non-utility	(89)	(72)	(190)
Investment in joint ventures	(36)	(34)	(21)
Proceeds from sale of ITC, synfuels and other assets	325	758	41
Restricted cash and other investments	(66)	37	(151)
	(681)	10	(1,115)
Financing activities :			
Issuance of long-term debt and common stock	777	571	1,403
Redemption of long-term debt	(759)	(1,208)	(793)
Short-term borrowings, net	33	(44)	(267)
Dividends on common stock and other	(363)	(358)	(359)
	(312)	(1,039)	(16)
Net Increase (Decrease) in Cash and Cash Equivalents	$ 2	$ (79)	$ (135)

Cash from Operating Activities

A majority of the Company's operating cash flow is provided by our two utilities, which are significantly influenced by factors such as weather, electric Customer Choice sales loss, regulatory deferrals, regulatory outcomes, economic conditions and operating costs.

Our non-utility businesses also provide sources of cash flow to the enterprise and reflect a range of operating profiles. The profiles vary from our synthetic fuels business, which we believe will provide over $1.6 billion in cash through 2008, to new start-ups. These new start-ups include our unconventional gas and waste coal recovery businesses, which we are growing and, if successful, could require significant investments.

Although DTE Energy's overall earnings were $431 million in 2004, cash from operations totaling $995 million was up $45 million from the comparable 2003 period. The operating cash flow comparison reflects an increase of over $300 million in net income, after adjusting for non-cash items (depreciation, depletion, amortization, deferred taxes and gains), substantially offset by a $259 million increase in working capital and other requirements. A portion of this improvement is attributable to the change in our strategy to primarily produce synfuel from plants in which we have sold interests. As previously discussed, synfuel projects generate operating losses, which have been more than offset by tax credits that we have been unable to fully utilize, thereby negatively affecting operating cash flow. Cash for working capital primarily reflects higher income tax payments of $172 million in 2004, reflecting a different payment pattern of taxes in 2004 compared to 2003. The increase in working capital was mitigated by Company initiatives to improve cash flow, including better inventory management, cash sales transactions, deferral of retirement plan contributions and the utilization of letters of credit. Certain cash initiatives in 2003 lowered cash flow in 2004.

Our net operating cash flow in 2003 was $950 million, reflecting a $46 million decline from 2002. The decrease was attributable to lower utility net income, after adjusting for non-cash items. Partially offsetting the declines were lower working capital and other requirements reflecting Company initiatives to improve cash flow and optimize synfuel operations. The improvement in 2003 working capital was achieved despite a $222 million contribution to our pension plans.

Outlook – We expect cash flow from operations to increase over the long-term primarily due to improvements from utility rate increases and the sales of interests in our synfuel projects. This will be partially offset by higher cash requirements, primarily within our gas storage business. We are continuing our efforts to identify opportunities to improve cash flow through cash improvement initiatives.

Operating cash flow from our utilities is expected to increase in 2005, but will be affected by the level of sales migration under the electric Customer Choice program and the ability of the MPSC within the regulatory processes to put in place a Customer Choice program that has sound economic fundamentals. In addition, the Customer Choice program's impact will also be determined by the success of the Company in addressing certain structural flaws within additional regulatory proceedings and the legislative process.

Another factor affecting utility cash flows is the degree and timing of rate relief within the electric and gas rate cases. Based on the final and interim orders issued by the MPSC in 2004, approximately $50 million of additional revenues were realized in the 2004 calendar year. Due to the structure of the interim and final rate orders, we will not realize the full benefits of interim and final rate relief until 2006 when all customer rate caps expire.

Improvements in cash flow from our utilities are also expected from better management of our working capital requirements, including the continued focus on reducing past due accounts receivable. Our emphasis in these businesses will continue to be centered around cash generation and conservation.

Cash flows from our synfuel business are expected to total approximately $1.6 billion between 2005 and 2008. The redeployment of this cash represents a unique opportunity to increase shareholder value and strengthen our balance sheet. We expect to use this cash to reduce debt, to continue to pursue growth investments that meet our strict risk-return and value creation criteria and to potentially repurchase common stock if adequate investment opportunities are not available. Our objectives for cash redeployment are to strengthen the balance sheet and coverage ratios in order to improve our current credit ratings and outlook, and to more than replace the value of synfuels.

Cash flows from our synfuel business are expected to approximate $400 million in 2005. The source of synfuel cash flow includes cash from operations (excluding certain working capital changes), asset sales, and the utilization of Section 29 tax credits carried forward from synfuel production prior to 2004.

Our other operating non-utility businesses are expected to contribute approximately $400 million through 2008. Remaining start-up businesses such as unconventional gas production, waste coal recovery and distributed generation will continue to use cash in excess of their cash generation over the next couple of years while they are being further developed. Certain of the previously discussed cash initiatives resulted in accelerating the receipt of cash in 2004, which will have the impact of lowering cash flow in 2005.

Cash from Investing Activities

Cash inflows associated with investing activities are primarily generated from the sale of assets. In any given year, we will look to harvest cash from under performing or non-strategic assets. Capital spending within the utility business is primarily to maintain our generation and distribution infrastructure, comply with environmental regulations and gas pipeline replacements. Capital spending within our non-utility businesses is for ongoing maintenance and some expansion. The balance of non-utility spending is for growth, which we manage very carefully. We look to make investments that meet strict criteria in terms of strategy, management skills, risks and returns. All new investments are analyzed for their rates of return and cash payback on a risk adjusted basis. We have been disciplined in how we deploy capital and will not make investments unless they meet our criteria. For new business lines, we invest tentatively based on research and analysis. Based on a limited investment, we evaluate results and either expand or exit the business based on those results. In any given year, the amount of growth capital will be determined by the underlying cash flows of the Company with a clear understanding of any potential impact on our credit ratings.

Net cash relating to investing activities declined $691 million in 2004 and improved $1.1 billion in 2003, compared to the prior year. The changes were primarily due to proceeds received in 2003 totaling $758 million from the sale of ITC, interests in three synfuel projects and non-strategic assets. Additionally, the changes are due to variations in cash contractually designated for debt service.

Longer term, with the expected improvement at our utilities and continued cash generation from the synfuel business, cash flows are expected to improve. We will continue to pursue opportunities to grow our businesses in a disciplined fashion if we can find opportunities that meet our strategic, financial and risk criteria.

Cash from Financing Activities

We rely on both short-term borrowings and longer-term financings as a source of funding for our capital requirements not satisfied by the Company's operations. Short-term borrowings, which are mostly in the form of commercial paper borrowings, provide us with the liquidity needed on a daily basis. Our commercial paper program is supported by our unsecured credit facilities.

DTE Energy and its subsidiaries have a total of $1.675 billion in credit facilities, which provide liquidity to our commercial paper programs and support the use of letters of credit.

(in Millions)	*Facility Amount*	*Maturity Date*
Issuing Entity		
DTE Energy	$ 375.00	5/5/2006
DTE Energy	175.00	10/24/2006
DTE Energy	525.00	10/15/2009
Detroit Edison	68.75	10/24/2006
Detroit Edison	206.25	10/15/2009
MichCon	81.25	10/24/2006
MichCon	243.75	10/15/2009
	$ 1,675.00	

Borrowings under the facilities are available at prevailing short-term interest rates. The agreements require each of the Companies to maintain a debt to total capitalization ratio of no more than .65 to 1 and an "earnings before interest, taxes, depreciation and amortization" (EBITDA) to interest ratio of no less than 2 to 1. DTE Energy has significant room under these provisions, with coverage totaling 4.3 to 1 and leverage at .489 to 1 at December 31, 2004. The Companies are currently in compliance with these financial covenants. Should either Detroit Edison or MichCon have delinquent debt obligations of at least $25 million to any creditor, such delinquency will be considered a default under DTE Energy's credit agreements. These agreements have standard material adverse change (MAC) clauses, however, the agreements expiring in October 2009 include a provision that the MAC clause does not apply when borrowings are made to repay maturing commercial paper.

Additionally, Detroit Edison has a $200 million short-term financing agreement secured by customer accounts receivable. The agreement contains certain covenants related to the delinquency of accounts receivable. Detroit Edison is currently in compliance with these covenants.

For additional information see Note 10 - Short-Term Credit Arrangements and Borrowings.

Our strategy is to have a targeted debt portfolio blend as to fixed and variable interest rates and maturity. We continually evaluate our leverage target, which is currently 50% or lower, to ensure it is consistent with our objective to have a strong investment grade debt rating. We have completed a number of refinancings with the effect of extending the average maturity of our long-term debt and strengthening our balance sheet. The extension of the average maturity was accomplished at interest rates that lowered our debt costs.

Net cash used for financing activities improved $727 million in 2004 and declined $1.0 billion in 2003, compared to the prior periods. The 2004 change was primarily due to higher issuances of new long and short-term debt and fewer repurchases of long-term debt. The 2003 change was due to higher redemptions of long-term debt and lower proceeds from issuances of new debt and common stock. For additional information on debt issuances and redemptions, see Note 9 - Long-Term Debt and Preferred Securities.

Amounts available under shelf registrations include $500 million at DTE Energy and $150 million at Detroit Edison. MichCon does not have current shelf capacity. In 2005, we plan on filing new shelf registration statements for MichCon and Detroit Edison.

Common stock issuances or repurchases can also be a source or use of cash. In January 2005, we announced the DTE Energy Board has authorized the repurchase of up to $700 million in common stock through 2008. The authorization provides Company management with flexibility to pursue share repurchases from time to time, and will depend on future cash flows and investment opportunities. In January 2005, we discontinued issuing new DTE Energy shares for our dividend reinvestment plan, which generated approximately $50 million annually. We also contributed $170 million of DTE Energy common stock to our pension plan in the first quarter of 2004.

Contractual Obligations

The following table details our contractual obligations for debt redemptions, leases, purchase obligations and other long-term obligations as of December 31, 2004:

(in Millions)	Total	Less Than 1 Year	1-3 Years	4-5 Years	After 5 Years
Contractual Obligations					
Long-Term Debt:					
Mortgage bonds, notes & other	$ 6,091	$ 410	$ 1,224	$ 759	$ 3,698
Securitization bonds	1,496	96	335	272	793
Equity-linked securities	178	5	173	–	–
Trust preferred-linked securities	289	–	–	–	289
Capital lease obligations	94	11	34	20	29
Interest	6,346	494	1,280	726	3,846
Operating leases	623	64	143	75	341
Electric, gas, fuel, transportation & storage purchase obligations*	6,130	3,694	1,601	236	599
Other long-term obligations	357	97	151	37	72
Total Obligations	$ 21,604	$ 4,871	$ 4,941	$ 2,125	$ 9,667

* Excludes amounts associated with full requirements contracts where no stated minimum purchase volume is required.

Credit Ratings

Credit ratings are intended to provide banks and capital market participants with a framework for comparing the credit quality of securities and not a recommendation to buy, sell or hold securities. Management believes that the current credit ratings of the Company provide sufficient access to the capital markets. However, disruptions in the banking and capital markets not specifically related to DTE Energy may affect the Company's ability to access these funding sources or cause an increase in the return required by investors.

In November 2004, Moody's Investors Service and Fitch Ratings downgraded MichCon. In December 2004, Standard & Poor's downgraded DTE Energy, Detroit Edison and MichCon. The ratings reflect weaker credit metrics due to decreased cash flows mainly stemming from increased operation and maintenance costs without sufficient regulatory relief. Additional unfavorable changes in our ratings could restrict our ability to access capital markets at attractive rates and increase our borrowing costs.

We have issued guarantees for the benefit of various non-utility subsidiaries. In the event that our credit rating is downgraded to below investment grade, certain of these guarantees would require us to post cash or letters of credit valued at approximately $356 million at December 31, 2004. Additionally, our trading business could be required to restrict operations and our access to the short-term commercial paper market could be restricted or eliminated. While we currently do not anticipate such a downgrade, we cannot predict the outcome of current or future reviews. The following table shows our credit rating as determined by three nationally respected credit rating agencies. All ratings are considered investment grade and affect the value of the related securities.

		Credit Rating Agency		
Entity	Description	Standard & Poors	Moody's Investors Service	Fitch Ratings
DTE Energy	Senior Unsecured Debt	BBB-	Baa2 *	BBB
	Commercial Paper	A-2	P-2*	F2
Detroit Edison	Senior Secured Debt	BBB+	A3 *	A-
	Commercial Paper	A-2	p-2*	F2
MichCon	Senior Secured Debt	BBB	A3	A-
	Commercial Paper	A-2	P-2	F2

* Currently on negative outlook

CRITICAL ACCOUNTING ESTIMATES

There are estimates used in preparing the consolidated financial statements that require considerable judgment. Such estimates relate to regulation, risk management and trading activities, Section 29 tax credits, goodwill, pension and postretirement costs, the allowance for doubtful accounts, and legal and tax reserves.

Regulation

A significant portion of our business is subject to regulation. Detroit Edison and MichCon currently meet the criteria of Statement of Financial Accounting Standards (SFAS) No. 71, *"Accounting for the Effects of Certain Types of Regulation."* Application of this standard results in differences in the application of generally accepted accounting principles between regulated and non-regulated businesses. SFAS No. 71 requires the recording of regulatory assets and liabilities for certain transactions that would have been treated as revenue or expense in non-regulated businesses. Future regulatory changes or changes in the competitive environment could result in discontinuing the application of SFAS No. 71 for some or all of our businesses. If we were to discontinue the application of SFAS No. 71 on all our operations, we estimate that the extraordinary loss would be as follows:

(in Millions)	
Utility	
Detroit Edison*	$ (138)
MichCon	(42)
Total	$ (180)

* Excludes securitized regulatory assets

Management believes that currently available facts support the continued application of SFAS No. 71 and that all regulatory assets and liabilities are recoverable or refundable in the current rate environment (Note 4).

Risk Management and Trading Activities

All derivatives are recorded at fair value and shown as "Assets or liabilities from risk management and trading activities" in the consolidated statement of financial position. Risk management activities are accounted for in accordance with SFAS No. 133, *"Accounting for Derivative Instruments and Hedging Activities,"* as amended. Through December 2002, trading activities were accounted for in accordance with Financial Accounting Standards Board (FASB) Emerging Issues Task Force (EITF) Issue No. 98-10, *"Accounting for Energy Trading and Risk Management Activities."* Effective January 2003, trading activities are accounted for in accordance with SFAS No. 133.
See Note 2 - New Accounting Pronouncements.

The offsetting entry to "Assets or liabilities from risk management and trading activities" is to other comprehensive income or earnings depending on the use of the derivative, how it is designated and if it qualifies for hedge accounting. The fair values of derivative contracts were adjusted each reporting period for changes using market sources such as:

- published exchange traded market data
- prices from external sources
- price based on valuation models

Market quotes are more readily available for short duration contracts. Derivative contracts are only marked to market to the extent that markets are considered highly liquid where objective, transparent prices can be obtained. Unrealized gains and losses are fully reserved for transactions that do not meet this criterion.

Section 29 Tax Credits

We generate Section 29 tax credits from our synfuel, coke battery and biomass operations. We recognize earnings as tax credits are generated at our facilities in one of two ways. First, to the extent we generate credits to our own account, we recognize earnings through reduced tax expense. Second, to the extent we have sold an interest in our synfuel facilities to third parties, we recognize gains as synfuel is produced and sold, and when there is persuasive evidence that the sales proceeds have become fixed or determinable and collectibility is reasonably assured.

All Section 29 tax credits taken after 1997 are subject to audit by the IRS, however, all of our synthetic fuel facilities have received favorable private letter rulings from the IRS with respect to their operations. Audits of four of our synfuel facilities for the years 2001 and 2002 were successfully completed during 2004. One synfuel facility is currently under audit. If our Section 29 tax credits were disallowed in whole or in part as a result of an IRS audit, there could be a significant write-off of previously recorded earnings from such tax credits.

Tax credits generated by our facilities were $449 million in 2004, as compared to $387 million in 2003 and $351 million in 2002. The portion of tax credits generated for our own account were $38 million in 2004, as compared to $241 million in 2003 and $250 million in 2002, with the remaining credits generated allocated to third party partners. Outside firms assist us in assuring we operate in accordance with our private letter rulings and within the parameters of the law, as well as calculating the value of tax credits.

Goodwill

Certain of our business units have goodwill resulting from purchase business combinations (Notes 2 and 16). In accordance with SFAS No. 142, *"Goodwill and Other Intangible Assets,"* each of our reporting units with goodwill is required to perform impairment tests annually or whenever events or circumstances indicate that the value of goodwill may be impaired. In order to perform these impairment tests, we must determine the reporting unit's fair value using valuation techniques, which use estimates of discounted future cash flows to be generated by the reporting unit. These cash flow valuations involve a number of estimates that require broad assumptions and significant judgment by management regarding future performance. To the extent estimated cash flows are revised downward, the reporting unit may be required to write down all or a portion of its goodwill, which would adversely impact our earnings.

As of December 31, 2004, our goodwill totaled $2.1 billion. The majority of our goodwill is allocated to our utility reporting units, with approximately $772 million allocated to the utility Energy Gas reporting unit. The value of the utility reporting units is significantly impacted by rate orders and the regulatory environment. The utility Energy Gas reporting unit is comprised primarily of MichCon. We have made certain cash flow assumptions for MichCon that are dependent upon the successful outcome of the outstanding gas rate case (Note 4). These assumptions may change when we receive a final rate order, which is expected during the first quarter of 2005.

Based on our 2004 goodwill impairment test, we determined that the fair value of our reporting units exceed their carrying value and no impairment existed. We will continue to monitor regulatory events, and evaluate their impact on our valuation assumptions and the carrying value of the related goodwill. While we believe our assumptions are reasonable, actual results may differ from our projections.

Pension and Postretirement Costs

Our costs of providing pension and postretirement benefits are dependent upon a number of factors, including rates of return on plan assets, the discount rate, the rate of increase in health care costs and the amount and timing of plan sponsor contributions.

We had pension costs for qualified pension plans of $81 million in 2004, $47 million in 2003, and pension income of $9 million in 2002. Postretirement benefits cost for all plans were $125 million in 2004, $118 million in 2003, and $70 million in 2002. Pension and postretirement benefits cost for 2004 is calculated based upon a number of actuarial assumptions, including an expected long-term rate of return on our plan assets of 9.0%. In developing our expected long-term rate of return assumption, we evaluated input from our consultants, including their review of asset class risk and return expectations as well as inflation assumptions. Projected returns are based on broad equity and bond markets. Our expected long-term rate of return on plan assets is based on an asset allocation assumption utilizing active investment management of 65% in equity markets, 28% in fixed income markets, and 7% invested in other assets. Because of market volatility, we periodically review our asset allocation and rebalance our portfolio when considered appropriate. Given market conditions, we believe 9.0% is a reasonable long-term rate of return on our plan assets. We will continue to evaluate our actuarial assumptions, including our expected rate of return, at least annually.

We base our determination of the expected return on qualified plan assets on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation recognizes changes in fair value in a systematic manner over a three-year period. Because of this method, the future value of assets will be impacted as previously deferred gains or losses are recorded. We have unrecognized net gains due to the recent favorable performance of the financial markets. As of December 31, 2004, we had $63 million of cumulative gains that remain to be recognized in the calculation of the market-related value of assets.

The discount rate that we utilize for determining future pension and postretirement benefit obligations is based on a review of bonds that receive one of the two highest ratings given by a recognized rating agency. The discount rate determined on this basis has decreased from 6.25% at December 31, 2003 to 6.0% at December 31, 2004. Due to recent financial market performance, lower discount rates and increased health care trend rates, we estimate that our 2005 pension costs will approximate $96 million compared to $81 million in 2004 and our 2005 postretirement benefit costs will approximate $155 million compared to $125 million in 2004. In the last several years we have made modifications to the pension and postretirement benefit plans to mitigate the earnings impact of higher costs. Future actual pension and postretirement benefit costs will depend on future investment performance, changes in future discount rates and various other factors related to plan design. Additionally, future pension costs for Detroit Edison will be affected by a pension tracking mechanism, which was authorized by the MPSC in its November 2004 rate order. The tracking mechanism provides for the recovery or refunding of pension costs above or below the amount reflected in Detroit Edison's base rates.

Lowering the expected long-term rate of return on our plan assets by 1.0% would have increased our 2004 qualified pension costs by approximately $24 million. Lowering the discount rate and the salary increase assumptions by 1.0% would have increased our pension costs for 2004 by approximately $8 million. Lowering the health care cost trend assumptions by 1.0% would have decreased our postretirement benefit service and interest costs for 2004 by approximately $17 million.

The market value of our pension and postretirement benefit plan assets has been affected by the financial markets. The value of our plan assets increased from $2.4 billion at December 31, 2002 to $2.9 billion at December 31, 2003. The value at December 31, 2004 increased to $3.3 billion. The investment performance returns and declining discount rates required us to recognize an additional minimum pension liability, an intangible asset and an entry to other comprehensive loss (shareholders' equity) at December 2002, 2003 and 2004. The additional minimum pension liability and related accounting entries will be reversed on the balance sheet in future periods if the fair value of plan assets exceeds the accumulated pension benefit obligations. The recording of the minimum pension liability does not affect net income or cash flow.

Pension and postretirement costs and pension cash funding requirements may increase in future years without substantial returns in the financial markets. We made a $35 million cash contribution to the pension plan in 2002, a $222 million cash contribution in 2003 and a $170 million contribution to our pension plan in the form of DTE Energy common stock in 2004. We also contributed $33 million to the postretirement plans in 2002 and contributed $80 million to the postretirement plans in 2004. We did not contribute to the postretirement plans in 2003. We do not anticipate making a contribution to our qualified pension plans in 2005. At the discretion of management, we anticipate making a $0 to $40 million contribution to our postretirement plans in 2005.

In December 2003, the Medicare Prescription Drug, Improvement and Modernization Act was signed into law. This Act provides for a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to the benefit established by law. The effects of the subsidy on the measurement of net periodic postretirement benefit costs reduced costs by $16 million in 2004.

See Note 14 – Retirement Benefits and Trusteed Assets for a further discussion of our pension and postretirement benefit plans.

Allowance for Doubtful Accounts

We establish an allowance for doubtful accounts based upon factors surrounding the credit risk of specific customers, historical trends, economic conditions, age of receivables and other information. Higher customer bills due to increased gas prices, the lack of adequate levels of assistance for low-income customers and economic conditions have also contributed to the increase in past due receivables. As a result of these factors, our allowance for doubtful accounts increased in 2003 and 2004. We believe the allowance for doubtful accounts is based on reasonable estimates. However, failure to make continued progress in collecting our past due receivables would unfavorably affect operating results and cash flow.

Legal and Tax Reserves

We are involved in legal and tax proceedings, claims and litigation arising in the ordinary course of business. We regularly assess our liabilities and contingencies in connection with asserted or potential matters, and establish reserves when appropriate. Legal reserves are based upon management's assessment of pending and threatened legal proceedings against the Company. Tax reserves are based upon management's assessment of potential adjustments to tax positions taken. We regularly review ongoing tax audits and prior audit experience, in addition to current tax and accounting authority in assessing potential adjustments.

ENVIRONMENTAL MATTERS

Protecting the environment, as well as correcting past environmental damage, continues to be a focus of state and federal regulators. Legislation and/or rulemaking could further impact the electric utility industry including Detroit Edison. The Environmental Protection Agency (EPA) and the Michigan Department of Environmental Quality have aggressive programs to clean-up contaminated property.

Air – The EPA ozone transport and acid rain regulations and final new air quality standards relating to ozone and particulate air pollution will continue to impact us. Detroit Edison has spent approximately $580 million through December 2004 and estimates that it will spend up to $100 million in 2005. Detroit Edison estimates it will incur from $700 million to $1.3 billion of additional future capital expenditures over the next five to eight years to satisfy both existing and proposed new control requirements. Recovery of costs to be incurred through December 2004 was provided for in our November 2004 electric rate order. See Note 4 – Regulatory Matters.

The EPA has initiated enforcement actions against several major electric utilities citing violations of the Clean Air Act, asserting that older, coal-fired power plants have been modified in ways that would require them to comply with the more restrictive "new source" provisions of the Clean Air Act. Detroit Edison received and responded to information requests from the EPA on this subject. The EPA has not initiated proceedings against Detroit Edison. The United States District Court for the Southern District of Ohio Eastern Division issued a decision in August 2003 finding Ohio Edison Company in violation of the new source provisions of the Clean Air Act. If the Court's decision is upheld, the electric utility industry could be required to invest substantial amounts on pollution control equipment. During the same month, however, a district court in a different division rendered a conflicting decision on the matter. On October 27, 2003, the EPA promulgated new rules, effective December 26, 2003, allowing repair, replacement or upgrade of production equipment without triggering source requirement controls if the cost of the parts and repairs do not exceed 20% of the replacement value of the equipment being upgraded. Such repairs will be considered routine maintenance, however any changes in emissions would be subject to existing pollution permit limits and other state and federal programs for pollutants. Several states and environmental organizations have challenged these regulations and, on December 24, 2003, were granted a stay until the U.S. Court of Appeals D.C. Circuit hears the arguments on the case. We cannot predict the future impact of this issue upon Detroit Edison.

Water – In July 2004, the EPA published final regulations establishing performance standards for reducing fish loss at existing power plant cooling water intake structures. These regulations require individual facility studies, and possible intake modifications that will be determined and implemented over the next five to seven years. It is estimated that we will incur up to $50 million in additional capital expenditures for Detroit Edison.

Contaminated Sites – DTE Enterprises Inc. (MichCon and Citizens) owns, or previously owned, 18 former manufactured gas plant (MGP) sites. During the mid-1980's, Enterprises conducted preliminary environmental investigations at former MGP sites, and some contamination related to the by-products of gas manufacturing was discovered at each site. Enterprises employed outside consultants to evaluate remediation alternatives and associated costs for these sites. As a result of these studies, Enterprises accrued a liability and a corresponding regulatory asset of $24 million. At December 31, 2004, the reserve balance was $24 million of which $4.5 million was classified as current. Our current estimates indicate that the previously accrued amounts are adequate to cover the costs of required remedial actions.

Detroit Edison conducted remedial investigations at contaminated sites, including two former MGP sites, the area surrounding an ash landfill and several underground and aboveground storage tank locations. The findings of these investigations indicated that the estimated cost to remediate these sites is approximately $8 million, which is expected to be incurred over the next several years. As a result of the investigation, Detroit Edison accrued approximately $8 million liability during 2004.

DTE ENERGY OPERATING SYSTEM AND DTE2

During 2002, we adopted the DTE Energy Operating System, which is the application of tools and operating practices that have resulted in operating efficiencies, inventory reductions and improvements in technology systems, among other enhancements. Operation and maintenance expenses benefited from our Company-wide initiative to pursue cost efficiencies and enhance operating performance. We expect continued cost containment efforts and process improvements.

In 2003, we began the implementation of DTE2, a Company-wide initiative to improve existing processes and to implement new core information systems including, finance, human resources, supply chain and work management. We expect to incrementally spend approximately $150 million to $175 million over the life of the project. We expect the benefits to outweigh this investment primarily from lower costs, faster business cycles, repeatable and optimized processes, enhanced internal controls, improvements in inventory management and reductions in system support costs.

We are in process of launching the first phase of our multi-year DTE2 project. Although our implementation plan includes detailed testing and contingency arrangements to ensure a smooth and successful transition, we can provide no assurance that complications will not arise that could interrupt our operations.

NEW ACCOUNTING PRONOUNCEMENTS

See Note 2 – New Accounting Pronouncements for discussion of new pronouncements.

FAIR VALUE OF CONTRACTS

The following disclosures are voluntary and we believe provide enhanced transparency of the derivative activities and position of our Energy Trading & Marketing segment and our other businesses.

We use the criteria in Statement of Financial Accounting Standards No. 133, *"Accounting for Derivative Instruments and Hedging Activities,"* as amended and interpreted, to determine if certain contracts must be accounted for as derivative instruments. The rules for determining whether a contract meets the criteria for derivative accounting are numerous and complex. Moreover, significant judgment is required to determine whether a contract requires derivative accounting, and similar contracts can sometimes be accounted for differently. If a contract is accounted for as a derivative instrument, it is recorded in the financial statements as Assets or Liabilities from Risk Management and Trading Activity, at the fair value of the contract. The recorded fair value of the contract is then adjusted quarterly to reflect any change in the fair value of the contract, a practice known as mark-to-market (MTM) accounting.

Fair value represents the amount at which willing parties would transact an arms-length transaction. To determine the fair value of contracts that are accounted for as derivative instruments, we use a combination of quoted market prices and mathematical valuation models. Valuation models require various inputs, including forward prices, volatility, interest rates, and exercise periods.

Contracts we typically classify as derivative instruments are power and gas forwards, futures, options and swaps, as well as foreign currency contracts. Items we do not generally account for as derivatives (and which are therefore excluded from the following tables) include gas inventory, gas storage and transportation arrangements, full-requirements power contracts and gas and oil reserves. As subsequently discussed, we have fully reserved the value of derivative contracts beyond the liquid trading timeframe and which therefore do not impact income.

The subsequent tables contain the following four categories represented by their operating characteristics and key risks.

- "Proprietary Trading" represents derivative activity transacted with the intent of taking a view, capturing market price changes, or putting capital at risk. This activity is speculative in nature as opposed to hedging an existing exposure.
- "Structured Contracts" represents derivative activity transacted with the intent to capture profits by originating substantially hedged positions with wholesale energy marketers, utilities, retail aggregators and alternative energy suppliers. Although transactions are generally executed with a buyer and seller simultaneously, some positions remain open until a suitable offsetting transaction can be executed.
  - "Economic Hedges" represents derivative activity associated with assets owned and contracted by DTE Energy, including forward sales of gas production and trades associated with owned transportation and storage capacity. Changes in the value of derivatives in this category economically offset changes in the value of underlying non-derivative positions, which do not qualify for fair value accounting. The difference in accounting treatment of derivatives in this category and the underlying non-derivative positions can result in significant earnings volatility as discussed in more detail in the preceding Results of Operations section.
  - "Gas Production" represents derivative activity associated with our Michigan gas reserves. A substantial portion of the price risk associated with these reserves has been mitigated through 2013. Changes in the value of the hedges are recorded as Liabilities from Risk Management and Trading with an offset in other comprehensive income to the extent that the hedges are deemed effective. The amounts shown in the following tables exclude the value of the underlying gas reserves and the changes therein.

roll forward of mark to market energy contract net assets

The following tables provide details on changes in our MTM net asset or (liability) position during 2004:

(in Millions)	Energy Marketing & Trading: Proprietary Trading	Structured Contracts	Economic Hedges	Total	Other Non-Trading Activities	Total
MTM at December 31, 2003	$ 10	$ 17	$ (171)	$ (144)	$ (81)	$ (225)
Reclassed to realized upon settlement	(10)	(10)	89	69	42	111
Changes in fair value recorded to income	5	12	(20)	(3)	(12)	(15)
Amortization of option premiums	(2)	–	–	(2)	–	(2)
Amounts recorded to unrealized income	(7)	2	69	64	30	94
Amounts recorded in OCI (Note 1)	–	4	–	4	(78)	(74)
Option premiums paid and other	–	–	4	4	29	33
MTM at December 31, 2004	$ 3	$ 23	$ (98)	$ (72)	$ (100)	$ (172)

The following table provides a current and noncurrent analysis of Assets and Liabilities from Risk Management and Trading Activities as reflected in the Consolidated Statement of Financial Position as of December 31, 2004. Amounts that relate to contracts that become due within twelve months are classified as current and all remaining amounts are classified as noncurrent.

(in Millions)	Energy Marketing & Trading: Proprietary Trading	Structured Contracts	Economic Hedges	Eliminations	Totals	Other Non-Trading Activities	Total Assets (Liabilities)
Current assets	$ 48	$ 115	$ 150	$ (33)	$ 280	$ 16	$ 296
Noncurrent assets	18	44	82	(19)	125	–	125
Total MTM assets	66	159	232	(52)	405	16	421
Current liabilities	(45)	(98)	(204)	33	(314)	(55)	(369)
Noncurrent liabilities	(18)	(38)	(126)	19	(163)	(61)	(224)
Total MTM liabilities	(63)	(136)	(330)	52	(477)	(116)	(593)
Total MTM net assets (liabilities)	$ 3	$ 23	$ (98)	$ –	$ (72)	$ (100)	$ (172)

Maturity of Fair Value of MTM Energy Contract Net Assets

As previously discussed, we fully reserve all unrealized gains and losses related to periods beyond the liquid trading timeframe. Our intent is to recognize MTM activity only when pricing data is obtained from active quotes and published indexes. Actively quoted and published indexes include exchange traded (i.e., NYMEX) and over-the-counter (OTC) positions for which broker quotes are available. The NYMEX has currently quoted prices for the next 72 months. Although broker quotes for gas and power are generally available for 18 and 24 months into the future, respectively, we fully reserve all unrealized gains and losses related to periods beyond the liquid trading timeframe and which therefore do not impact income.

The table below shows the maturity of our MTM positions:

Source of Fair Value (in Millions)	2005	2006	2007	2008 and Beyond	Total Fair Value
Proprietary Trading	$ 3	$ (2)	$ 2	$ –	$ 3
Structured Contracts	17	4	1	1	23
Economic Hedges	(55)	(27)	(16)	–	(98)
Total Energy Marketing & Trading	(35)	(25)	(13)	1	(72)
Other Non-Trading Activities	(38)	(51)	(11)	–	(100)
Total	$ (73)	$ (76)	$ (24)	$ 1	$ (172)

Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

DTE Energy has commodity price risk arising from market price fluctuations in conjunction with the anticipated purchase of electricity to meet its obligations during periods of peak demand. We also are exposed to the risk of market price fluctuations on gas sale and purchase contracts, gas production and gas inventories. To limit our exposure to commodity price fluctuations, we have entered into a series of electricity and gas futures, forwards, option and swap contracts. Commodity price risk associated with our electric and gas utilities is limited due to the PSCR and GCR mechanisms (Note 1).

Our Energy Services and Biomass businesses are also subject to crude oil price risk. As previously discussed, the Section 29 tax credits generated by DTE Energy's synfuel and biomass operations are subject to phase out if domestic crude oil prices reach certain levels.

See Note 12 – Financial and Other Derivative Instruments for further discussion.

Credit Risk

Bankruptcies

We purchase and sell electricity, gas, coal, coke and other energy products from and to numerous companies operating in the steel, automotive, energy, retail and other industries. A number of customers have filed for bankruptcy protection under Chapter 11 of the U.S. Bankruptcy Code. We have negotiated or are currently involved in negotiations with each of the companies, or their successor companies, that have filed for bankruptcy protection. We regularly review contingent matters relating to purchase and sale contracts and record provisions for amounts considered at risk of probable loss. We believe our accrued amounts are adequate for probable losses. The final resolution of these matters is not expected to have a material effect on our financial statements in the period they are resolved.

We engage in business with customers that are non-investment grade. We closely monitor the credit ratings of these customers and, when deemed necessary, we request collateral or guarantees from such customers to secure their obligations.

Energy Trading & CoEnergy Portfolio

We utilize both external and internally generated credit assessments when determining the credit quality of our trading counterparties. The following table displays the credit quality of our trading counterparties as of December 31, 2004:

(in Millions)	Credit Exposure before Cash Collateral	Cash Collateral	Net Credit Exposure
Investment Grade (1)			
A- and Greater	$ 234	$ (2)	$ 232
BBB+ and BBB	191	(18)	173
BBB-	17	–	17
Total Investment Grade	442	(20)	422
Non-investment grade (2)	15	–	15
Internally Rated – investment grade (3)	78	(1)	77
Internally Rated – non-investment grade (4)	2	–	2
Total	$ 537	$ (21)	$ 516

(1) This category includes counterparties with minimum credit ratings of Baa3 assigned by Moody's Investors Service (Moody's) and BBB- assigned by Standard & Poor's Rating Group (Standard & Poor's). The five largest counterparty exposures combined for this category represented 28% of the total gross credit exposure.

(2) This category includes counterparties with credit ratings that are below investment grade. The five largest counterparty exposures combined for this category represented less than 2% of the total gross credit exposure.

(3) This category includes counterparties that have not been rated by Moody's or Standard & Poor's, but are considered investment grade based on DTE Energy's evaluation of the counterparty's creditworthiness. The five largest counterparty exposures combined for this category represented 9% of the total gross credit exposure.

(4) This category includes counterparties that have not been rated by Moody's or Standard & Poor's, and are considered non-investment grade based on DTE Energy's evaluation of the counterparty's creditworthiness. The five largest counterparty exposures combined for this category represented less than 1% of the gross credit exposure.

Interest Rate Risk

DTE Energy is subject to interest rate risk in connection with the issuance of debt and preferred securities. In order to manage interest costs, we use treasury locks and interest rate swap agreements. Our exposure to interest rate risk arises primarily from changes in U.S. Treasury rates, commercial paper rates and London Inter-Bank Offered Rates (LIBOR). As of December 31, 2004, the Company has a floating rate debt to total debt ratio of approximately 11% (excluding securitized debt).

Foreign Currency Risk

DTE Energy has foreign currency exchange risk arising from market price fluctuations associated with fixed priced contracts. These contracts are denominated in Canadian dollars and are primarily for the purchase and sale of power as well as for long-term transportation capacity. To limit our exposure to foreign currency fluctuations, we have entered into a series of currency forward contracts through 2008.

Summary of Sensitivity Analysis

We performed a sensitivity analysis to calculate the fair values of our commodity contracts, long-term debt instruments and foreign currency forward contracts. The sensitivity analysis involved increasing and decreasing forward rates at December 31, 2004 by a hypothetical 10% and calculating the resulting change in the fair values of the commodity, debt and foreign currency agreements.

The results of the sensitivity analysis calculations follow:

Activity *(in Millions)*	Assuming a 10% increase in rates	Assuming a 10% decrease in rates	Change in the fair value of
Gas Contracts	$ (18)	$ 18	Commodity contracts
Power Contracts	$ 1	$ (2)	Commodity contracts
Oil Contracts	$ 15	$ (8)	Commodity options
Interest Rate Risk	$ (311)	$ 325	Long-term debt
Foreign Currency Risk	$ –	$ –	Forward contracts

report of management's responsibility

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Financial Statements

We have reviewed this annual report to shareholders, and based on our knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report. Also, based on our knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of opertions and cash flows of DTE Energy as of, and for, the periods presented.

Internal Control Over Financial Reporting

The management of DTE Energy Company is responsible for establishing and maintaining adequate internal control over financial reporting. DTE Energy Company's internal control system was designed to provide reasonable assurance to the company's management and board of directors regarding the preparation and fair presentation of published financial statements.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Projections of any evaluation of the effectiveness to future periods are subject to the risks that control may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

DTE Energy Company management assessed the effectiveness of the company's internal control over financial reporting as of December 31, 2004. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control—Integrated Framework.* Based on our assessment, management believes that, as of December 31, 2004, DTE Energy Company's internal control over financial reporting was effective based on those criteria.

Our management's assessment of the effectiveness of the company's internal control over financial reporting has been audited by DTE Energy's independent auditors, as stated in their report which is included herein.

Anthony F. Early Jr.

Anthony F. Early Jr.
Chairman, Chief Executive and Chief Operating Officer

David E. Meador

David E. Meador
Executive Vice President and Chief Financial Officer

reports of independent registered public accounting firm

To the Board of Directors and Shareholders of DTE Energy Company:

We have audited management's assessment, included in the accompanying Management's report on Internal Control Over Financial Reporting, that DTE Energy Company and subsidiaries (the "Company") maintained effective internal control over financial reporting as of December 31, 2004, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on the criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on the criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements of the Company as of December 31, 2004 and for the year then ended; and our report dated March 15, 2005 expressed an unqualified opinion on those consolidated financial statements.

Deloitte & Touche LLP

Detroit, Michigan
March 15, 2005

Deloitte.
Deloitte & Touche LLP
Suite 900, 600 Renaissance Center
Detroit, Michigan 48243-1704

To the Board of Directors and Shareholders of DTE Energy Company:

We have audited the consolidated statement of financial position of DTE Energy Company and subsidiaries (the "Company") as of December 31, 2004 and 2003, and the related consolidated statements of operations, cash flows, and changes in shareholders' equity and comprehensive income for each of the three years in the period ended December 31, 2004. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the consolidated 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 audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. 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 financial position of DTE Energy Company and subsidiaries at December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, in connection with the required adoption of certain new accounting principles, in 2003 the Company changed its method of accounting for asset retirement obligations, energy trading contracts and gas inventories and in 2002 the Company changed its method of accounting for goodwill and energy trading contracts.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting as of December 31, 2004, 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 March 15, 2005 expressed an unqualified opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting and an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Deloitte & Touche LLP

Detroit, Michigan
March 15, 2005

Deloitte.
Deloitte & Touche LLP
Suite 900, 600 Renaissance Center
Detroit, Michigan 48243-1704

consolidated statement of operations

(In Millions, Except per Share Amounts)		2004		2003		2002
						Year Ended December 31
Operating Revenues	$	**7,114**	$	7,041	$	6,729
Operating Expenses						
Fuel, purchased power and gas		**2,007**		2,241		2,099
Operation and maintenance		**3,420**		3,109		2,589
Depreciation, depletion and amortization		**744**		687		737
Taxes other than income		**312**		334		352
Asset gains and losses, net		**(215)**		(77)		(42)
		6,268		6,294		5,735
Operating Income		**846**		747		994
Other (Income) and Deductions						
Interest expense		**518**		546		569
Interest income		**(55)**		(37)		(29)
Other income		**(80)**		(110)		(45)
Other expenses		**67**		82		34
		450		481		529
Income Before Income Taxes and Minority Interest		**396**		266		465
Income Tax Provision (Benefit) (Note 7)		**165**		(123)		(84)
Minority Interest		**(212)**		(91)		(37)
Income from Continuing Operations		**443**		480		586
Income (Loss) from Discontinued Operations, net of tax (Note 3)		**(12)**		68		46
Cumulative Effect of Accounting Changes, net of tax (Note 2)		**–**		(27)		–
Net Income	$	**431**	$	521	$	632
Basic Earnings per Common Share (Note 8)						
Income from continuing operations	$	**2.56**	$	2.87	$	3.57
Discontinued operations		**(.06)**		.41		.28
Cumulative effect of accounting changes		**–**		(.17)		–
Total	$	**2.50**	$	3.11	$	3.85
Diluted Earnings per Common Share (Note 8)						
Income from continuing operations	$	**2.55**	$	2.85	$	3.55
Discontinued operations		**(.06)**		.40		.28
Cumulative effect of accounting changes		**–**		(.16)		–
Total	$	**2.49**	$	3.09	$	3.83
Average Common Shares						
Basic		**173**		168		164
Diluted		**173**		168		165
Dividends Declared per Common Share	$	**2.06**	$	2.06	$	2.06

See Notes to Consolidated Financial Statements

consolidated statement
# of financial position

(in Millions)	December 31 2004	2003
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 56**	$ 54
Restricted cash (Note 1)	**126**	131
Accounts receivable		
Customer (less allowance for doubtful accounts of $129 and $99, respectively)	**880**	877
Accrued unbilled revenues	**378**	316
Other	**383**	338
Inventories		
Fuel and gas	**509**	467
Materials and supplies	**159**	162
Assets from risk management and trading activities	**296**	186
Other	**209**	181
	2,996	2,712
Investments		
Nuclear decommissioning trust funds	**590**	518
Other	**558**	601
	1,148	1,119
Property		
Property, plant and equipment	**18,011**	17,679
Less accumulated depreciation and depletion (Note 2)	**(7,520)**	(7,355)
	10,491	10,324
Other Assets		
Goodwill (Note 3)	**2,067**	2,067
Regulatory assets (Note 4)	**2,119**	2,063
Securitized regulatory assets (Note 4)	**1,438**	1,527
Notes receivable	**529**	469
Assets from risk management and trading activities	**125**	88
Prepaid pension assets	**184**	181
Other	**200**	203
	6,662	6,598
Total Assets	**$ 21,297**	$ 20,753

See Notes to Consolidated Financial Statements

(in Millions, Except Shares)		December 31 2004		2003
LIABILITIES AND SHAREHOLDERS' EQUITY				
Current Liabilities				
Accounts payable	$	**892**	$	625
Accrued interest		**111**		110
Dividends payable		**90**		87
Accrued payroll		**33**		51
Income taxes		**16**		185
Short-term borrowings		**403**		370
Current portion long-term debt, including capital leases		**514**		477
Liabilities from risk management and trading activities		**369**		326
Other		**581**		593
		3,009		2,824
Other Liabilities				
Deferred income taxes		**1,124**		988
Regulatory liabilities (Notes 2 and 4)		**817**		817
Asset retirement obligations (Note 2)		**916**		866
Unamortized investment tax credit		**143**		156
Liabilities from risk management and trading activities		**224**		173
Liabilities from transportation and storage contracts		**387**		495
Accrued pension liability		**265**		345
Deferred gains from asset sales		**414**		311
Minority interest		**132**		156
Nuclear decommissioning (Notes 2 and 5)		**77**		67
Other		**635**		599
		5,134		4,973
Long-Term Debt (net of current portion) (Note 9)				
Mortgage bonds, notes and other		**5,673**		5,624
Securitization bonds		**1,400**		1,496
Equity-linked securities		**178**		185
Trust preferred-linked securities		**289**		289
Capital lease obligations		**66**		75
		7,606		7,669
Commitments and Contingencies (Notes 4, 5 and 13)				
Shareholders' Equity				
Common stock, without par value, 400,000,000 shares authorized, 174,209,034 and 168,606,522 shares issued and outstanding, respectively		**3,323**		3,109
Retained earnings		**2,383**		2,308
Accumulated other comprehensive loss		**(158)**		(130)
		5,548		5,287
Total Liabilities and Shareholders' Equity	$	**21,297**	$	20,753

See Notes to Consolidated Financial Statements

consolidated statement of cash flow

(in Millions)						*Year Ended December 31*
		2004		2003		2002
Operating Activities						
Net income	$	**431**	$	521	$	632
Adjustments to reconcile net income to net cash from operating activities:						
Depreciation, depletion and amortization		**744**		691		759
Deferred income taxes		**129**		(220)		(208)
Gain on sale of interests in synfuel projects		**(219)**		(83)		(40)
Gain on sale of ITC and other assets, net		**(17)**		(145)		–
Partners' share of synfuel project losses		**(223)**		(78)		(40)
Contributions from synfuel partners		**141**		65		22
Cumulative effect of accounting changes		**–**		27		–
Changes in assets and liabilities, exclusive of changes shown separately (Note 1)		**9**		172		(129)
Net cash from operating activities		**995**		950		996
Investing Activities						
Plant and equipment expenditures – utility		**(815)**		(679)		(794)
Plant and equipment expenditures – non-utility		**(89)**		(72)		(190)
Investments in joint ventures		**(36)**		(34)		(21)
Proceeds from sale of interests in synfuel projects		**221**		89		32
Proceeds from sale of ITC and other assets		**104**		669		9
Restricted cash for debt redemptions		**5**		106		(79)
Other investments		**(71)**		(69)		(72)
Net cash from (used for) investing activities		**(681)**		10		(1,115)
Financing Activities						
Issuance of long-term debt		**736**		527		1,138
Redemption of long-term debt		**(759)**		(1,208)		(793)
Short-term borrowings, net		**33**		(44)		(267)
Issuance of common stock		**41**		44		265
Dividends on common stock		**(354)**		(346)		(338)
Other		**(9)**		(12)		(21)
Net cash used for financing activities		**(312)**		(1,039)		(16)
Net Increase (Decrease) in Cash and Cash Equivalents		**2**		(79)		(135)
Cash and Cash Equivalents at Beginning of Period		**54**		133		268
Cash and Cash Equivalents at End of Period	$	**56**	$	54	$	133

See Notes to Consolidated Financial Statements

consolidated statement of changes in shareholders' equity and comprehensive income

(dollars in Millions, shares in Thousands)	common stock shares	common stock amounts	retained earnings	accumulated other comprehensive loss	total
Balance, December 31, 2001	161,134	$ 2,811	$ 1,846	$ (68)	$ 4,589
Net income	–	–	632	–	632
Issuance of new shares	6,426	270	–	–	270
Dividends declared on common stock	–	–	(341)	–	(341)
Repurchase and retirement of common stock	(98)	(1)	(2)	–	(3)
Pension obligations (Note 14)	–	–	–	(518)	(518)
Net change in unrealized losses on derivatives, net of tax	–	–	–	(33)	(33)
Unearned stock compensation and other	–	(28)	(3)	–	(31)
Balance, December 31, 2002	167,462	3,052	2,132	(619)	4,565
Net income	–	–	521	–	521
Issuance of new shares	1,225	57	–	–	57
Dividends declared on common stock	–	–	(348)	–	(348)
Repurchase and retirement of common stock	(80)	(1)	–	–	(1)
Pension obligations (Note 14)	–	–	–	420	420
Net change in unrealized losses on derivatives, net of tax	–	–	–	17	17
Net change in unrealized gains on investments, net of tax	–	–	–	52	52
Unearned stock compensation and other	–	1	3	–	4
Balance, December 31, 2003	168,607	3,109	2,308	(130)	5,287
Net income	–	–	431	–	431
Issuance of new shares	5,671	223	–	–	223
Dividends declared on common stock	–	–	(357)	–	(357)
Repurchase and retirement of common stock	(69)	(3)	–	–	(3)
Pension obligations (Note 14)	–	–	–	7	7
Net change in unrealized losses on derivatives, net of tax	–	–	–	(15)	(15)
Net change in unrealized losses on investments, net of tax	–	–	–	(20)	(20)
Unearned stock compensation and other	–	(6)	1	–	(5)
Balance, December 31, 2004	**174,209**	**$ 3,323**	**$ 2,383**	**$ (158)**	**$ 5,548**

The following table displays comprehensive income (loss):

(In Millions)	2004	2003	2002
Net income	**$ 431**	$ 521	$ 632
Other comprehensive income (loss), net of tax:			
Pension obligations, net of taxes of $(4), $(226) and $280 (Notes 4 and 14)	**7**	420	(518)
Net unrealized losses on derivatives:			
Gains or (losses) arising during the period, net of taxes of $26, $(8) and $32	**(49)**	16	(60)
Amounts reclassified to earnings, net of taxes of $(18), $- and $(15)	**34**	1	27
	(15)	17	(33)
Net unrealized gains (losses) on investments:			
Gains (losses) arising during the period, net of taxes of $3, $(28) and $-	**(5)**	52	–
Amounts reclassified to earnings, net of taxes of $8, $- and $-	**(15)**	–	–
	(20)	52	–
Comprehensive Income	**$ 403**	**$ 1,010**	**$ 81**

See Notes to Consolidated Financial Statements

notes to consolidated financial statements

NOTE-1 SIGNIFICANT ACCOUNTING POLICIES

Corporate Structure

DTE Energy is an exempt holding company under the Public Utility Holding Company Act of 1935 and owns the following businesses:

notes

- The Detroit Edison Company (Detroit Edison), an electric utility engaged in the generation, purchase, distribution and sale of electric energy to 2.1 million customers in southeast Michigan;
- Michigan Consolidated Gas Company (MichCon), a natural gas utility engaged in the purchase, storage, transmission and distribution and sale of natural gas to 1.2 million customers throughout Michigan; and
- Other non-utility subsidiaries engaged in energy marketing and trading, energy services and various other electricity, coal and gas related businesses.

Detroit Edison and MichCon are regulated by the Michigan Public Service Commission (MPSC). The Federal Energy Regulatory Commission (FERC) regulates certain activities of Detroit Edison's business as well as various other aspects of businesses under DTE Energy. In addition, we are regulated by other federal and state regulatory agencies including the Nuclear Regulatory Commission (NRC) and the Environmental Protection Agency, among others.

Segments realigned – Through 2004, we operated our businesses through three strategic business units (Energy Resources, Energy Distribution and Energy Gas). Each business unit had utility and non-utility operations. The balance of our business consisted of Corporate & Other. See Note 16 for further discussion. In 2005, we expect to realign our business units to strengthen the Company's focus on customer relationships and growth within our non-utility businesses. Based on this structure, we will set strategic goals, allocate resources and evaluate performance. Beginning with the first quarter of 2005, we expect to report our segment information based on the following realignment:

- *Electric Utility*, consisting of Detroit Edison;
- *Gas Utility*, primarily consisting of MichCon;
- Non-utility Operations
  - *Power and Industrial Projects,* primarily consisting of synfuel projects, on-site energy services, steel-related projects, power generation with services, and waste coal recovery operations;
  - *Unconventional Gas Production,* primarily consisting of gas production and coal bed methane operations;
  - *Fuel Transportation and Marketing,* primarily consisting of coal transportation and marketing, gas pipelines and storage, and energy marketing and trading operations; and
- *Corporate & Other,* primarily consisting of corporate support functions and certain energy technology investments.

References in this report to "we," "us," "our" or "Company" are to DTE Energy and its subsidiaries, collectively.

Principles of Consolidation

We consolidate all majority owned subsidiaries and investments in entities in which we have controlling influence. Non-majority owned investments are accounted for using the equity method when the company is able to influence the operating policies of the investee. Non-majority owned investments include investments in limited liability companies, partnerships or joint ventures. When we do not influence the operating policies of an investee, the cost method is used. We eliminate all intercompany balances and transactions.

For entities that are considered variable interest entities, we apply the provisions of Financial Accounting Standards Board (FASB) Interpretation No. (FIN) 46-R, *"Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51."* For a detailed discussion of FIN 46-R, see Note 2 – New Accounting Pronouncements.

Basis of Presentation

The accompanying consolidated financial statements are prepared using accounting principles generally accepted in the United States of America. These accounting principles require us to use estimates and assumptions that impact reported amounts of assets, liabilities, revenues and expenses, and the disclosure of contingent assets and liabilities. Actual results may differ from our estimates.

Prior to December 2004, DTE Energy did not eliminate amounts, principally within Other Income and Other Deductions, resulting from certain intercompany transactions. The amounts of the transactions are immaterial and had no effect on net income. Previously reported prior period amounts have been adjusted to eliminate those intercompany transactions and are now consistent with the current year's presentation. We reclassified certain other prior year balances to match the current year's financial statement presentation.

Revenues

Revenues from the sale and delivery of electricity, and the sale, delivery and storage of natural gas are recognized as services are provided. Detroit Edison and MichCon record revenues for electric and gas provided but unbilled at the end of each month.

Detroit Edison's accrued revenues include a component for the cost of power sold that is recoverable through the Power Supply Cost Recovery (PSCR) mechanism. MichCon's accrued revenues include a component for the cost of gas sold that is recoverable through the Gas Cost Recovery (GCR) mechanism. Annual PSCR and GCR proceedings before the MPSC permit Detroit Edison and MichCon to recover prudent and reasonable supply costs. Any overcollection or undercollection of costs, including interest, will be reflected in future rates. Prior to 2004, Detroit Edison's retail rates were frozen under Public Act (PA) 141. See Note 4 for further discussion. Accordingly, Detroit Edison did not accrue revenues under the PSCR mechanism prior to 2004.

Non-utility businesses recognize revenues as services are provided and products are delivered. Our Energy Marketing & Trading segment records in revenues net unrealized derivative gains and losses on energy trading contracts, including those to be physically settled.

Gains from Sale of Interests in Synthetic Fuel Facilities

Through December 2004, we have sold majority interests in eight of our nine synthetic fuel production plants, representing approximately 92% of our total production capacity. Proceeds from the sales are contingent upon production levels and the value of Section 29 tax credits. Section 29 tax credits are subject to phase out if domestic crude oil prices reach certain levels. See Note 13 for further discussion. We recognize gains from the sale of interests in the synfuel facilities as synfuel is produced and sold, and when there is persuasive evidence that the sales proceeds have become fixed or determinable and collectibility is reasonably assured. We have recorded gains from the sale of interests in synthetic fuel facilities totaling $219 million, $83 million and $40 million during 2004, 2003 and 2002, respectively.

Until the gain recognition criteria are met, gains from selling interests in synfuel facilities will be deferred. It is possible that gains will be deferred in the first, second and/or third quarters of each year until there is persuasive evidence that no tax credit phase out will occur for the applicable calendar year. This could result in shifting earnings from earlier quarters to later quarters of a calendar year.

Comprehensive Income

We comply with Statement of Financial Accounting Standards (SFAS) No. 130, *"Reporting Comprehensive Income,"* that established standards for reporting comprehensive income. SFAS No. 130 defines comprehensive income as the change in common shareholders' equity during a period from transactions and events from non-owner sources, including net income. As shown in the following table, amounts recorded to other comprehensive income (OCI) at December 31, 2004 include: unrealized gains and losses from derivatives accounted for as cash flow hedges under SFAS No. 133, *"Accounting for Derivative Instruments and Hedging Activities;"* unrealized gains and losses on available for sale securities under SFAS No. 115, *"Accounting for Certain Investments in Debt and Equity Securities;"* and, minimum pension liabilities as prescribed by SFAS No. 87, *"Employers' Accounting for Pensions."*

(in Millions)	Minimum Pension Liability Adjustment	Net Unrealized Losses on Derivatives	Net Unrealized Gains on Investments	Accumulated Other Comprehensive Loss
Beginning balance	$ (98)	$ (85)	$ 53	$ (130)
Current-period change	7	(15)	(20)	(28)
Ending balance	$ (91)	$ (100)	$ 33	$ (158)

Cash Equivalents and Restricted Cash

Cash and cash equivalents include cash on hand, cash in banks and temporary investments purchased with remaining maturities of three months or less. Restricted cash consists of funds held to satisfy requirements of certain debt and partnership operating agreements. Restricted cash is classified as a current asset as all restricted cash is designated for interest and principal payments due within one year.

Inventories

We value fuel inventory and materials and supplies at average cost.

Gas inventory at MichCon is determined using the last-in, first-out (LIFO) method. At December 31, 2004, the replacement cost of gas remaining in storage exceeded the $89 million LIFO cost by $330 million. At December 31, 2003, the replacement cost of gas remaining in storage exceeded the $117 million LIFO cost by $251 million. During 2004, MichCon liquidated 5.7 billion cubic feet of prior years' LIFO layers. The liquidation benefited 2004 cost of gas by approximately $7 million, but had no impact on earnings as a result of the GCR mechanism.

Our Energy Marketing & Trading segment uses the average cost method for its gas in inventory.

Property, Retirement and Maintenance, and Depreciation and Depletion

Summary of property by classification as of December 31:

(in Millions)	2004	2003
Property, Plant and Equipment		
Electric Utility		
Generation	**$ 7,100**	$ 6,938
Distribution	**5,831**	5,733
Total Electric Utility	**12,931**	12,671
Gas Utility		
Distribution	**2,020**	1,961
Storage	**221**	224
Other	**883**	855
Total Gas Utility	**3,124**	3,040
Energy Services		
Coal Based Fuels	**651**	652
On-Site Energy	**193**	180
Merchant Generation	**174**	229
Other	**8**	13
Total Energy Services	**1,026**	1,074
Other Non-utility and Other	**930**	894
Total Property, Plant and Equipment	**18,011**	17,679
Less Accumulated Depreciation and Depletion		
Electric Utility		
Generation	**(3,277)**	(3,231)
Distribution	**(2,077)**	(2,108)
Total Electric Utility	**(5,354)**	(5,339)
Gas Utility		
Distribution	**(845)**	(798)
Storage	**(100)**	(102)
Other	**(448)**	(432)
Total Gas Utility	**(1,393)**	(1,332)
Energy Services		
Coal Based Fuels	**(272)**	(219)
On-Site Energy	**(55)**	(42)
Merchant Generation	**(18)**	(20)
Other	**(3)**	(2)
Total Energy Services	**(348)**	(283)
Other Non-utility and Other	**(425)**	(401)
Total Accumulated Depreciation and Depletion	**(7,520)**	(7,355)
Net Property, Plant and Equipment	**$ 10,491**	$ 10,324

Property is stated at cost and includes construction-related labor, materials, overheads and an "allowance for funds used during construction" (AFUDC). The cost of properties retired, less salvage, at Detroit Edison and MichCon are charged to accumulated depreciation.

Expenditures for maintenance and repairs are charged to expense when incurred, except for Fermi 2. Approximately $3.8 million of expenses related to the anticipated Fermi 2 refueling outage scheduled for 2006 were accrued at December 31, 2004. Amounts are being accrued on a pro-rata basis over an 18-month period that began in November 2004. We have utilized the accrue-in-advance policy for nuclear refueling outage costs since the Fermi 2 plant was placed in service in 1988. This method also matches the regulatory recovery of these costs in rates set by the MPSC.

We base depreciation provisions for utility property at Detroit Edison and MichCon on straight-line and units of production rates approved by the MPSC. The composite depreciation rate for Detroit Edison was 3.4% in 2004, 2003 and 2002. The composite depreciation rate for MichCon was 3.6%, 3.5%, and 3.6% in 2004, 2003 and 2002, respectively.

The average estimated useful life for each class of utility property, plant and equipment as of December 31, 2004 follows:

Estimated Useful Lives in Years

Utility	Generation	Distribution	Transmission
Electric	39	37	–
Gas	N/A	26	28

Non-utility property is depreciated over its estimated useful life using straight-line, declining-balance or units-of-production methods.

We credit depreciation, depletion and amortization expense when we establish regulatory assets for stranded costs related to the electric Customer Choice program and deferred environmental expenditures.

Gas Production

We follow the successful efforts method of accounting for investments in gas properties. Under this method of accounting, all property acquisition costs and costs of exploratory and development wells are capitalized when incurred, pending determination of whether the well has found proved reserves. If an exploratory well has not found proved reserves, the costs of drilling the well are expensed. The costs of development wells are capitalized, whether productive or nonproductive. Geological and geophysical costs on exploratory prospects and the costs of carrying and retaining unproved properties are expensed as incurred. An impairment loss is recorded to the extent that capitalized costs of unproved properties, on a property-by-property basis, are considered not to be realizable. An impairment loss is recorded if the net capitalized costs of proved gas properties exceed the aggregate related undiscounted future net revenues. Depreciation, depletion and amortization of proved gas properties are determined using the units-of-production method.

Long-Lived Assets

Our long-lived assets are reviewed for impairment whenever events or changes in circumstances indicate the carrying amount of an asset may not be recoverable. If the carrying amount of the asset exceeds the expected future cash flows generated by the asset, an impairment loss is recognized resulting in the asset being written down to its estimated fair value. Assets to be disposed of are reported at the lower of the carrying amount or fair value less cost to sell.

Intangible Assets, Including Software Costs

Our intangible assets consist primarily of software. We capitalize the costs associated with computer software we develop or obtain for use in our business. We amortize intangible assets on a straight-line basis over expected periods of benefit. Intangible assets amortization expense was $43 million in 2004, $40 million in 2003 and $46 million in 2002. The gross carrying amount and accumulated amortization of intangible assets at December 31, 2004 were $445 million and $151 million, respectively. The gross carrying amount and accumulated amortization of intangible assets at December 31, 2003 were $537 million and $303 million, respectively. Amortization expense of intangible assets is estimated to be $40 million annually for 2005 through 2009.

Excise and Sales Taxes

We record the billing of excise and sales taxes as receivable with an offsetting payable to the applicable taxing authority, with no impact on the consolidated statement of operations.

Deferred Debt Costs

The costs related to the issuance of long-term debt are deferred and amortized over the life of each debt issue. In accordance with MPSC regulations applicable to our electric and gas utilities, the unamortized discount, premium and expense related to debt redeemed with a refinancing are amortized over the life of the replacement issue. Discount, premium and expense on early redemptions of debt associated with non-utility operations are charged to earnings.

Insured and Uninsured Risks

We have a comprehensive insurance program in place to provide coverage for various types of risks. Our insurance policies cover risk of loss from various events, including property damage, general liability, workers' compensation, auto liability and directors' and officers' liability.

Under our risk management policy, we self-insure portions of certain risks up to specified limits, depending on the type of exposure. We periodically review our insurance coverage. During 2003, we reviewed our process for estimating and recognizing reserves for self-insured risks. As a result of this review, we revised the process for estimating liabilities under our self-insured layers to include an actuarially determined estimate of "incurred but not reported" (IBNR) claims. We have an actuarially determined estimate of our IBNR liability prepared annually and adjust the related reserve as appropriate.

Stock-Based Compensation

We have a stock-based employee compensation plan, which is described in Note 15. The plan permits the awarding of various stock awards, including options, restricted stock and performance shares. We account for stock awards under the plan under the recognition and measurement principles of Accounting Principles Board (APB) Opinion No. 25, *"Accounting for Stock Issued to Employees."* No compensation cost related to stock options is reflected in earnings, as all options granted had an exercise price equal to the market value of the underlying common stock on the date of grant. The recognition provisions under SFAS No. 123, *"Accounting for Stock-Based Compensation,"* require the recording of compensation expense for stock options equal to their fair value at date of grant as determined using an option pricing model. The following table illustrates the effect on net income and earnings per share if we had recorded compensation expense for options granted under the fair value recognition provisions of SFAS No. 123.

(in Millions, except per share amounts)	2004	2003	2002
Net Income As Reported	$ **431**	$ 521	$ 632
Less: Total Stock-based Expense (1)	**(6)**	(7)	(7)
Pro Forma Net Income	$ **425**	$ 514	$ 625
Income Per Share			
Basic – as reported	$ **2.50**	$ 3.11	$ 3.85
Basic – pro forma	$ **2.46**	$ 3.06	$ 3.81
Diluted – as reported	$ **2.49**	$ 3.09	$ 3.83
Diluted – pro forma	$ **2.45**	$ 3.05	$ 3.79

(1) Expense determined using a Black-Scholes based option pricing model.

Investments in Debt and Equity Securities

We generally classify investments in debt and equity securities as either trading or available-for-sale and have recorded such investments at market value with unrealized gains or losses included in earnings or in other comprehensive income or loss, respectively. Changes in the fair value of nuclear decommissioning-related investments are recorded as adjustments to regulatory assets or liabilities (Note 5).

Investment in Plug Power

In 1997, we invested in Plug Power Inc., a company that designs and develops on-site electric fuel cell power generation systems. Since Plug Power is considered a development stage company, generally accepted accounting principles required us to record gains and losses from Plug Power stock issuances as an adjustment to equity. Prior to November 2003, we accounted for our investment in Plug Power under the equity method of accounting. We did not participate in Plug Power's secondary stock offering in November 2003 and as of December 31, 2003 we owned 14.1 million shares or approximately 19% of Plug Power's common stock. We have determined that we do not have the ability to exercise significant influence over the operating or financial policies of Plug Power. Accordingly, we began prospective application of the cost method of accounting for our investment in Plug Power, effective November 2003. We record our investment at market value and account for unrealized gains and losses in other comprehensive income or loss. In May 2004, we sold 3.5 million shares of Plug Power stock and recorded a gain of approximately $14 million, net of taxes. The sale reduced our ownership interest in Plug Power to 10.6 million shares, or approximately 14%.

Consolidated Statement of Cash Flows

A detailed analysis of the changes in assets and liabilities that are reported in the consolidated statement of cash flows follows:

(in Millions)	2004	2003	2002
Changes in Assets and Liabilities, Exclusive of Changes Shown Separately			
Accounts receivable, net	$ **73**	$ (50)	$ (129)
Accrued unbilled receivable	**(62)**	(20)	(54)
Accrued GCR revenue	**(35)**	29	(5)
Inventories	**(40)**	(61)	(71)
Accrued/Prepaid Pensions	**88**	(196)	(10)
Accounts payable	**266**	(21)	66
Accrued PSCR refund	**112**	–	–
Exchange gas payable	**(43)**	90	9
Income taxes payable	**(170)**	135	(8)
General taxes	**(14)**	(12)	(36)
Risk management and trading activities	**(64)**	127	69
Postretirement obligation	**29**	112	77
Other	**(131)**	39	(37)
	$ **9**	$ 172	$ (129)

Supplementary cash and non-cash information for the years ended December 31 were as follows:

(in Millions)	2004	2003	2002
Cash Paid For			
Interest (excluding interest capitalized)	$ **517**	$ 552	$ 551
Income taxes	$ **203**	$ 31	$ 167
Noncash Investing and Financing Activities			
Notes received from sale of synfuel projects	$ **214**	$ 238	$ 217
Common stock contributed to pension plan	$ **170**	$ –	$ –
Exchange of debt	$ **–**	$ 100	$ –
Issuance of equity-linked securities	$ **–**	$ –	$ 21

See the following notes for other accounting policies impacting our financial statements:

Note	Title
2	New Accounting Pronouncements
4	Regulatory Matters
7	Income Taxes
12	Financial and Other Derivative Instruments
14	Retirement Benefits and Trusteed Assets

NOTE 2 NEW ACCOUNTING PRONOUNCEMENTS

Energy Trading Activities

Under Emerging Issues Task Force (EITF) Issue No. 98-10, *"Accounting for Contracts Involved in Energy Trading and Risk Management Activities,"* companies were required to use mark-to-market accounting for contracts utilized in energy trading activities. EITF Issue No. 98-10 was rescinded in October 2002, and energy trading contracts must now be reviewed to determine if they meet the definition of a derivative under SFAS No. 133, *"Accounting for Derivative Instruments and Hedging Activities."* SFAS No. 133 requires all derivatives to be recognized in the statement of financial position as either assets or liabilities measured at their fair value. SFAS No. 133 also requires that changes in the fair value of derivatives be recognized in earnings unless specific hedge accounting criteria are met. Energy trading contracts not meeting the definition of a derivative are accounted for under settlement accounting, effective October 25, 2002 for new contracts and effective January 1, 2003 for existing contracts. Derivative contracts are only marked to market to the extent that markets are considered highly liquid where objective, transparent prices can be obtained. Unrealized gains and losses are fully reserved for transactions that do not meet this criteria.

Additionally, inventory utilized in energy trading activities accounted for under the fair value method of accounting as prescribed by Accounting Research Bulletin (ARB) No. 43 is no longer permitted. Our Energy Marketing & Trading segment uses gas inventory in its trading operations and switched from the fair value method to the average cost method in January 2003.

Effective January 1, 2003, we no longer applied EITF Issue No. 98-10 to energy contracts and ARB No. 43 to gas inventory. As a result of discontinuing the application of these accounting principles, we recorded a cumulative effect of accounting change that reduced net income for the first quarter of 2003 by $16 million (net of taxes of $9 million).

Asset Retirement Obligations

On January 1, 2003, we adopted SFAS No. 143, *"Accounting for Asset Retirement Obligations,"* which requires the fair value of an asset retirement obligation be recognized in the period in which it is incurred. We identified a legal retirement obligation for the decommissioning costs for our Fermi 1 and 2 nuclear plants. To a lesser extent, we have retirement obligations for our synthetic fuel operations, gas production facilities, asphalt plant, gas gathering facilities and various other operations. As to utility operations, we believe that adoption of SFAS No. 143 results primarily in timing differences in the recognition of legal asset retirement costs that we are currently recovering in rates and are deferring such differences under SFAS No. 71, *"Accounting for the Effects of Certain Types of Regulation."*

As a result of adopting SFAS No. 143 on January 1, 2003, we recorded a plant asset of $306 million with offsetting accumulated depreciation of $106 million, a retirement obligation liability of $815 million and reversed previously recognized obligations of $377 million, principally nuclear decommissioning liabilities. We also recorded a cumulative effect amount related to utility operations as a regulatory asset of $221 million, and a cumulative effect charge against earnings of $11 million (net of tax of $7 million) for 2003.

If a reasonable estimate of fair value cannot be made in the period the asset retirement obligation is incurred, such as assets with an indeterminate life, the liability is to be recognized when a reasonable estimate of fair value can be made. Generally, distribution assets have an indeterminate life, retirement cash flows cannot be determined and there is a low probability of retirement, therefore no liability has been recorded for these assets.

The pro forma effect on earnings had SFAS No. 143 been adopted for all periods presented would decrease reported net income and basic and diluted earnings per share as follows:

Year	(in Millions) Net Income	Basic and Diluted Earnings per Share
2002	$ 4.8	$ .03

A reconciliation of the asset retirement obligation for 2004 follows:

(in Millions)	
Asset retirement obligations at January 1, 2004	$ 866
Accretion	57
Liabilities settled	(5)
Revisions in estimated cash flows	(2)
Asset retirement obligations at December 31, 2004	$ 916

A significant portion of the asset retirement obligations represents nuclear decommissioning liabilities, which are funded through a surcharge to electric customers over the life of the Fermi 2 nuclear plant.

SFAS No. 143 also requires the quantification of the estimated cost of removal obligations, arising from other than legal obligations, which have been accrued through depreciation charges. At December 31, 2003, we reclassified approximately $655 million of previously accrued asset removal costs related to our utility operations, which had been previously netted against accumulated depreciation to regulatory liabilities. There is a generic case before the MPSC to determine the accounting and regulatory treatment of removal costs for Michigan utilities.

Consolidation of Variable Interest Entities

In January 2003, FASB Interpretation No. (FIN) 46, *"Consolidation of Variable Interest Entities, an Interpretation of Accounting Research Bulletin (ARB) No. 51,"* was issued and requires an investor with a majority of the variable interests (primary beneficiary) in a variable interest entity to consolidate the assets, liabilities and results of operations of the entity. A variable interest entity is an entity in which the equity investors do not have controlling interests, the equity investment at risk is insufficient to finance the entity's activities without receiving additional subordinated financial support from other parties, or equity investors do not share proportionally in gains or losses.

In October 2003 and December 2003, the FASB issued Staff Position No. FIN 46-6 and FIN 46-Revised (FIN 46-R), respectively, which clarified and replaced FIN 46 and also provided for the deferral of the effective date of FIN 46 for certain variable interest entities. We have evaluated all of our equity and non-equity interests and have adopted all current provisions of FIN 46-R. The adoption of FIN 46-R did not have a material effect on our financial statements.

Medicare Act Accounting

In December 2003, the *"Medicare Prescription Drug, Improvement and Modernization Act of 2003"* (Medicare Act) was signed into law. The Medicare Act provides for a non-taxable federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least "actuarially equivalent" to the benefit established by law. We elected at that time to defer the provisions of the Medicare Act, and its impact on our accumulated postretirement benefit obligation and net periodic postretirement benefit cost, pending the issuance of specific authoritative accounting guidance by the FASB.

In May 2004, FASB Staff Position (FSP) No. 106-2 was issued on accounting for the effects of the Medicare Act. The guidance in this FSP is applicable to sponsors of single-employer defined benefit postretirement health care plans for which (a) the employer has concluded the prescription drug benefits available under the plan to some or all participants are "actuarially equivalent" to Medicare Part D and thus qualify for the subsidy under the Medicare Act and (b) the expected subsidy will offset or reduce the employer's share of the cost of the underlying postretirement prescription drug coverage on which the subsidy is based. We believe we qualify for the subsidy under the Medicare Act and the expected subsidy will partially offset our share of the cost of postretirement prescription drug coverage.

In June 2004, we adopted FSP No. 106-2, retroactive to January 1, 2004. As a result of the adoption, our accumulated postretirement benefit obligation for the subsidy related to benefits attributed to past service was reduced by approximately $95 million and was accounted for as an actuarial gain. The effects of the subsidy reduced net postretirement costs by $16 million in 2004.

Stock Based Payments

In December 2004, the FASB issued SFAS No. 123-R, *"Stock Based Payments,"* which establishes the accounting for transactions in which an entity exchanges equity instruments for goods or services. Application of SFAS No. 123-R is required for interim or annual periods beginning after June 15, 2005 with earlier adoption encouraged. We have completed a preliminary review and estimate that the new standard will reduce reported earnings by approximately $5 million to $10 million per year.

Goodwill and Other Intangible Assets

Effective January 1, 2002, we adopted SFAS No. 142, *"Goodwill and Other Intangible Assets,"* which addresses the financial accounting and reporting standards for the acquisition of intangible assets outside of a business combination and for goodwill and other intangible assets subsequent to their acquisition. This accounting standard requires that goodwill no longer be amortized, but reviewed at least annually for impairment. In accordance with SFAS No. 142, we discontinued the amortization of goodwill effective January 1, 2002.

NOTE-3 DISPOSITIONS

International Transmission Company – Discontinued Operation

In February 2003, we sold International Transmission Company (ITC), our electric transmission business, for $610 million to affiliates of Kohlberg Kravis Roberts & Co. and Trimaran Capital Partners, LLC. The sale generated a preliminary net of tax gain of $63 million in 2003. The gain was net of transaction costs, the portion of the gain that was refundable to customers and the write off of approximately $44 million of allocated goodwill. The gain was lowered to $58 million in 2004 under the MPSC's November 2004 final rate order that resulted in a revision of the applicable transaction costs and customer refund.

As prescribed by SFAS No. 144, *"Accounting for the Impairment or Disposal of Long-Lived Assets,"* we have reported the operations of ITC as a discontinued operation as shown in the following table:

(in Millions)	2003 (3)	2002
Revenues (1)	$ 21	$ 138
Expenses (2)	13	67
Operating income	8	71
Income taxes	3	25
Income from discontinued operations	$ 5	$ 46

(1) Includes intercompany revenues of $18 million for 2003 and $118 million for 2002.

(2) Excludes general corporate overhead costs that were previously allocated to ITC in 2003 and 2002.

(3) Represents activity from January 1, 2003 through February 28, 2003, when ITC was sold.

Detroit Edison's Steam Heating Business

In January 2003, we sold Detroit Edison's steam heating business to Thermal Ventures II, LP. Due to the continuing involvement of Detroit Edison in the steam heating business, including the commitment to purchase steam and/or electricity through 2024, fund certain capital improvements and guarantee the buyer's credit facility, we recorded a net of tax loss of approximately $14 million in 2003. As a result of Detroit Edison's continuing involvement, this transaction is not considered a sale for accounting purposes. The steam heating business had assets of $6 million at December 31, 2002, and had net losses of $12 million in 2002. See Note 13 – Commitments and Contingencies.

Southern Missouri Gas Company – Discontinued Operation

We own Southern Missouri Gas Company (SMGC), a public utility engaged in the distribution, transmission and sale of natural gas in southern Missouri. In the first quarter of 2004, management approved the marketing of SMGC for sale. As of March 31, 2004, SMGC met the SFAS No. 144 criteria of an asset "held for sale," and we have reported its operating results as a discontinued operation. We recognized a net of tax impairment loss of approximately $7 million in 2004, representing the write-down to fair value of the assets of SMGC, less costs to sell, and the write-off of allocated goodwill. In November 2004, we entered into a definitive agreement providing for the sale of SMGC. Following receipt of regulatory approvals and resolution of other contingencies, it is anticipated that the transaction will close in 2005. SMGC had assets of $9 million and liabilities of $35 million at December 31, 2004.

NOTE-4 REGULATORY MATTERS

Regulation

Detroit Edison and MichCon are subject to the regulatory jurisdiction of the MPSC, which issues orders pertaining to retail rates, recovery of certain costs, including the costs of generating facilities and regulatory assets, conditions of service, accounting and operating-related matters. Detroit Edison is also regulated by the FERC with respect to financing authorization and wholesale electric activities.

As subsequently discussed in the "Electric Industry Restructuring" section, Detroit Edison's rates were frozen through 2003 and capped for small business customers through 2004 and for residential customers through 2005 as a result of Public Act (PA) 141. However, Detroit Edison was allowed to defer certain costs to be recovered once rates could be increased, including costs incurred as a result of changes in taxes, laws and other governmental actions.

Regulatory Assets and Liabilities

Detroit Edison and MichCon apply the provisions of SFAS No. 71, *"Accounting for the Effects of Certain Types of Regulation,"* to their regulated operations. SFAS No. 71 requires the recording of regulatory assets and liabilities for certain transactions that would have been treated as revenue and expense in non-regulated businesses. Continued applicability of SFAS No. 71 requires that rates be designed to recover specific costs of providing regulated services and be charged to and collected from customers. Future regulatory changes or changes in the competitive environment could result in the Company discontinuing the application of SFAS No. 71 for some or all of its utility businesses and may require the write-off of the portion of any regulatory asset or liability that was no longer probable of recovery through regulated rates. Management believes that currently available facts support the continued application of SFAS No. 71 to Detroit Edison and MichCon.

The following are balances and a brief description of the regulatory assets and liabilities at December 31:

(in Millions)	2004	2003
Assets		
Securitized regulatory assets	$ 1,438	$ 1,527
Recoverable income taxes related to securitized regulatory assets	$ 788	$ 837
Recoverable minimum pension liability	605	585
Asset retirement obligation	183	192
Other recoverable income taxes	109	114
Recoverable costs under PA 141		
Net stranded costs	122	68
Excess capital expenditures	7	–
Deferred Clean Air Act expenditures	76	54
Midwest Independent System Operator charges	27	21
Transmission integration costs	–	10
Electric Customer Choice implementation costs	95	84
Enhanced security costs	8	6
Unamortized loss on reacquired debt	63	60
Deferred environmental costs	31	29
Accrued GCR revenue	55	19
Other	5	3
	2,174	2,082
Less amount included in current assets	(55)	(19)
	$ 2,119	$2,063
Liabilities		
Asset removal costs	$ 679	$ 655
Excess securitization savings	–	14
Customer refund – 1997 storm	2	2
Refundable income taxes	135	146
Accrued GCR potential disallowance	28	26
Accrued PSCR refund	112	–
Other	3	3
	959	846
Less amount included in current liabilities	(142)	(29)
	$ 817	$ 817

ASSETS

- *Securitized regulatory assets* – The net book balance of the Fermi 2 nuclear plant was written off in 1998 and an equivalent regulatory asset was established. In 2001, the Fermi 2 regulatory asset and certain other regulatory assets were securitized pursuant to PA 142 and an MPSC order. A non-bypassable securitization bond surcharge recovers the securitized regulatory asset over a fourteen-year period ending in 2015.
- *Recoverable income taxes related to securitized regulatory assets* – Receivable for the recovery of income taxes to be paid on the non-bypassable securitization bond surcharge. A non-bypassable securitization tax surcharge recovers the income tax.
- *Recoverable minimum pension liability* – An additional minimum pension liability was recorded under generally accepted accounting principles due to the current under funded status of certain pension plans. The traditional rate setting process allows for the recovery of pension costs as measured by generally accepted accounting principles. Accordingly, the minimum pension liability associated with utility operations is recoverable. See Notes 4 and 14.
- *Asset retirement obligation* – Asset retirement obligations were recorded pursuant to adoption of SFAS No. 143 in 2003. These obligations are primarily for Fermi 2 decommissioning costs that are recovered in rates.
- *Other recoverable income taxes* – Income taxes receivable from Detroit Edison's customers representing the difference in property-related deferred income taxes receivable and amounts previously reflected in Detroit Edison's rates.
- *Net stranded costs* – PA 141 permits, after MPSC authorization, the recovery of and a return on fixed cost deficiency associated with the electric Customer Choice program. Net stranded costs occur when fixed cost related revenues do not cover the fixed cost revenue requirements.
- *Excess capital expenditures* – Starting in 2004, PA 141 permits, after MPSC authorization, the recovery of and a return on capital expenditures that exceed a base level of depreciation expense.
- *Deferred Clean Air Act expenditures* – PA 141 permits, after MPSC authorization, the recovery of and a return on Clean Air Act expenditures.
- *Midwest Independent System Operator charges* – PA 141 permits, after MPSC authorization, the recovery of and a return on charges from a regional transmission operator such as the Midwest Independent System Operator.
- *Transmission integration costs* – The MPSC's November 2004 final rate order denied recovery and determined these costs to be transaction expenses in DTE Energy's sale of ITC.
- *Electric Customer Choice implementation costs* – PA 141 permits, after MPSC authorization, the recovery of and a return on costs incurred associated with the implementation of the electric Customer Choice program.
- *Enhanced security costs* – PA 141 permits, after MPSC authorization, the recovery of enhanced homeland security costs for an electric generating facility.
- *Unamortized loss on reacquired debt* – The unamortized discount, premium and expense related to debt redeemed with a refinancing are deferred, amortized and recovered over the life of the replacement issue.
- *Deferred environmental costs* – The MPSC approved the deferral and recovery of investigation and remediation costs associated with former manufactured gas plant sites.
- *Accrued GCR revenue* – Receivable for the temporary under-recovery of and a return on gas costs incurred by MichCon which are recoverable through the GCR mechanism.

LIABILITIES

- *Asset removal costs* – The amount collected from customers for the funding of future asset removal activities.
- *Excess securitization savings* – Savings associated with the 2001 securitization of Fermi 2 and other costs are refundable to Detroit Edison's customers.

- *Customer refund – 1997 storm* – The over collection of 1997 storm costs, which will be refunded in accordance with the MPSC's November 2004 rate order.
- *Refundable income taxes* – Income taxes refundable to MichCon's customers representing the difference in property-related deferred income taxes payable and amounts recognized pursuant to MPSC authorization.
- *Accrued GCR potential disallowance* – Potential refund resulting from an MPSC order in MichCon's 2002 GCR plan case that required MichCon to reduce revenues in the calculation of its 2002 GCR expense.
- *Accrued PSCR refund* – Payable for the temporary over-recovery of and a return on power supply costs and, beginning with the MPSC's November 2004 rate order, transmission costs incurred by Detroit Edison which are recoverable through the PSCR mechanism.

Electric Rate Case

Rate Request – In June 2003, Detroit Edison filed an application with the MPSC requesting a change in retail electric rates, resumption of the PSCR mechanism, and recovery of net stranded costs. The application and subsequent revisions resulted in a request to increase base rates by $583 million annually.

In addition, Detroit Edison requested recovery of certain regulatory assets. As subsequently discussed, Detroit Edison received interim and final rate orders relating to its June 2003 rate application.

A summary of the rate orders follows:

(in Millions)	Interim Rate Increase(1)	Final Rate Increase(1)
Base Rate Revenue Deficiency	$ 248	$ 336
Recovery of SMC Discounts	–	38
Overall Base Rate Increase	248	374
PSCR Savings	(126)	(126)
Total	$ 122	$ 248

(in Millions)	Actual 2004	Estimate 2005 (2)	Total
Cumulative Recoverable Regulatory Assets			
Clean Air Act	$ 76	$ 68	$ 144
MISO Transmission Costs	27	49	76
Excess Capital Expenditures	7	15	22
Customer Refund – 1997 Storm	(2)	–	(2)
	108	132	240
Electric Choice Implementation Costs	95	6	101
Net Stranded Costs	44	–	44
Total	$ 247	$ 138	$ 385

(1) The impact of rate caps not included.

(2) Represents estimated amounts to be incurred in 2005, as well as carrying costs on unrecovered balances, that were authorized for recovery by the MPSC. Actual amounts incurred are subject to review in future MPSC proceedings, and any overcollections or undercollections will be reflected in future rates.

MPSC Interim Rate Order – On February 20, 2004, the MPSC issued an order for interim rate relief. The order authorized an interim increase in base rates, a transition charge for customers participating in the electric Customer Choice program and a new PSCR factor.

The interim base rate increase totaled $248 million annually, effective February 21, 2004, and was applicable to all customers not subject to a rate cap. The increase was allocated to both full-service customers ($240 million) and electric Customer Choice customers ($8 million). However, because of the rate caps under PA 141, not all of the increase was realized in 2004. The interim order also terminated certain transition credits and authorized transition charges to electric Customer Choice customers designed to result in $30 million in additional revenues. Additionally, the MPSC authorized a reduced PSCR factor for all customers, designed to lower revenues by $126 million annually. However, the MPSC order allowed Detroit Edison to increase base rates for customers still subject to the cap in an equal and offsetting amount with the required reduction in the PSCR factor to maintain the total capped rate levels currently in effect for these customers.

The MPSC deferred addressing other items in the rate request, including a surcharge to recover regulatory assets, until a final rate order was issued.

MPSC Final Rate Order – On November 23, 2004, the MPSC issued an order for final rate relief. The MPSC determined that the base rate increase granted to Detroit Edison should be $336 million annually effective November 24, 2004 and is applicable to all customers not subject to the rate cap. The final order provides for the future recovery of losses resulting from electric Customer Choice. Additionally, beginning in 2005, the final order allows Detroit Edison to recover the discounts previously provided to special manufacturing contract (SMC) customers of $38 million, resulting in an overall base rate increase of $374 million annually. As subsequently discussed, Detroit Edison has been deferring certain costs as regulatory assets that it believes are recoverable under PA 141 once rate caps expire. The final order addressed numerous issues relating to regulatory assets, including the amounts recoverable and the recovery mechanism. The final order authorized the recovery of a lower level of stranded costs than had been recorded through February 20, 2004, the date of the interim order. Accordingly, Detroit Edison adjusted its net stranded costs related regulatory asset, which decreased 2004 net income by $21 million.

The MPSC's final order authorizes the recovery of approximately $385 million of regulatory assets through three mechanisms:

- The first mechanism recovers certain accrued regulatory assets over a five-year period using a regulatory asset recovery surcharge (RARS) and is collectible from all full service customers as their rate caps expire. The total amount to be collected is estimated to be $240 million, plus carrying costs of 9.74% on unrecovered balances. The recoverable regulatory assets include costs associated with Clean Air Act compliance, deferred Midwest Independent System Operator (MISO) transmission fees, and deferred excess capital expenditures. The MPSC also authorized the refunding of over collected 1997 storm costs.
- The second mechanism includes a surcharge to recover electric Customer Choice implementation costs of $101 million and is collectible from both full service and electric Customer Choice customers. This charge will not be implemented until all current rate caps expire in 2006 and will include carrying costs of 7% on unrecovered balances.
- The third mechanism includes a surcharge to recover $44 million in historical stranded costs incurred in 2002, 2003 and January and February 2004 and is collectible from electric Customer Choice customers, including carrying costs of 7% on unrecovered balances.

Other significant items authorized by the MPSC in its final order:

- Rate increase was based on a 54% debt and 46% equity capital structure, and an 11% rate of return on common equity.
- Customer rate caps do not expire until January 2006. As a result, the MPSC determined that there is a need to true-up stranded costs for at least 2004. This true-up case must be filed by March 31, 2005. The MPSC also permits Detroit Edison to file additional annual stranded cost true-up proceedings if it deems appropriate to do so pursuant to PA 141.
- Transmission and MISO costs and costs associated with nitrogen oxide (NOx) allowances will be recoverable through the PSCR mechanism and charged to full service customers; however, costs associated with sulfur dioxide (SOx) allowances will not be included in the PSCR, but recoverable through base rates.
- Full cost recovery of $550 million of Clean Air Act environmental expenditures was authorized. We believe that future mandated environmental expenditures will also be recovered through base rates.
- A pension tracking mechanism was established to manage changes in pension costs. Under the tracking mechanism, Detroit Edison would recover or refund pension costs above or below the amount reflected in base rates. Detroit Edison was also required to propose a similar tracking mechanism for retiree health care costs. In February 2005, Detroit Edison filed a request with the MPSC seeking authority to implement a tracking mechanism for retiree health care costs (Other Postemployment Benefits Costs Tracker).
- Detroit Edison was ordered to file a rate unbundling and restructuring case by March 23, 2005. As subsequently discussed, this rate restructuring proposal was filed on February 4, 2005.
- Changes to the existing electric Customer Choice program regarding customers returning to full utility service. Customers electing to participate in the electric Customer Choice program will not be permitted to return to Detroit Edison's full service rates for two years. Electric Customer Choice customers returning to full service must remain on bundled rates for at least one year following their return. Customers who fail to give the appropriate notice or do not stay on the electric Customer Choice program for two years are required to pay the higher of the applicable tariff energy price plus 10%, or the market price of power plus 10%, for any power taken from Detroit Edison.

In December 2004, Detroit Edison and other parties filed petitions for rehearing relating to the MPSC's November 2004 final rate order. Among other items, Detroit Edison's petition requests a correction of the capital structure used in determination of the final order and recovery of certain disallowed costs. Detroit Edison awaits an MPSC decision on the petitions for rehearing.

Electric Rate Restructuring Proposal

On February 4, 2005, Detroit Edison filed a rate restructuring proposal with the MPSC to restructure its electric rates and begin phasing out subsidies that are part of its current pricing structure. The proposal would adjust rates for each customer class to be reflective of the full costs incurred to service such customers. Under the proposal, commercial and industrial rates would be lowered, but residential rates would increase over a five-year period beginning in 2007. The MPSC anticipates that this proceeding will be completed in time to have new rates in effect no later than January 1, 2006.

Other Postemployment Benefits Costs Tracker

On February 10, 2005, Detroit Edison filed an application requesting MPSC approval of a proposed tracking mechanism for retiree health care costs. The application was filed as required pursuant to the MPSC's November 2004 order.

Electric Industry Restructuring

Electric Rates, Customer Choice and Stranded Costs – In 2000, the Michigan Legislature enacted PA 141 that reduced electric retail rates by 5%, as a result of savings derived from the issuance of securitization bonds. The legislation also contained provisions freezing rates through 2003 and preventing rate increases (i.e., rate caps) for small business customers through 2004 and for residential customers through 2005. The price freeze period expired on February 20, 2004 pursuant to an MPSC order. In addition, PA 141 codified the MPSC's existing electric Customer Choice program and provided Detroit Edison with the right to recover net stranded costs associated with Customer Choice. Detroit Edison was also allowed to defer certain costs to be recovered once rates could be increased, including costs incurred as a result of changes in taxes, laws and other governmental actions.

As required by PA 141, the MPSC conducted a proceeding to develop a methodology for calculating net stranded costs associated with electric Customer Choice. In a December 2001 order, the MPSC determined that Detroit Edison could recover net stranded costs associated with the fixed cost component of its electric generation operations. Specifically, there would be an annual proceeding or true-up before the MPSC reconciling the receipt of revenues associated with the fixed cost component of its generation services to the revenue requirement for the fixed cost component of those services, inclusive of an allowance for the cost of capital. Any resulting shortfall in recovery, net of mitigation, would be considered a net stranded cost. The MPSC authorized Detroit Edison to establish a regulatory asset to defer recovery of its incurred stranded costs, subject to review in a subsequent annual net stranded cost proceeding.

In July 2003, the MPSC issued an order finding that Detroit Edison had no net stranded costs in 2000 and 2001. Detroit Edison filed a petition for rehearing of the July 2003 order, which the MPSC denied in December 2003. Detroit Edison has appealed. As previously discussed, the MPSC's November 2004 final order authorized recovery of $44 million of historical stranded costs incurred in 2002, 2003 and January and February 2004 collectible from electric Customer Choice customers through transition charges. Since March 1, 2004, Detroit Edison has recorded $108 million of additional stranded costs as a regulatory asset as the result of rate caps and higher electric Customer Choice sales losses than included in the 2004 MPSC interim order.

Securitization – Detroit Edison formed The Detroit Edison Securitization Funding LLC (Securitization LLC), a wholly owned subsidiary, for the purpose of securitizing its qualified costs, primarily related to the unamortized investment in the Fermi 2 nuclear power plant. In March 2001, the Securitization LLC issued $1.75 billion of securitization bonds, and Detroit Edison sold $1.75 billion of qualified costs to the Securitization LLC. The Securitization LLC is independent of Detroit Edison, as is its ownership of the qualified costs. Due to principles of consolidation, the qualified costs and securitization bonds appear on the company's consolidated statement of financial position. The Company makes no claim to these assets. Ownership of such assets has vested in the Securitization LLC and been assigned to the trustee for the securitization bonds. Neither the qualified costs nor funds from an MPSC approved non-bypassable surcharge collected from Detroit Edison's customers for the payment of costs related to the Securitization LLC and securitization bonds are available to Detroit Edison's creditors.

Excess Securitization Savings – In January 2004, the MPSC issued an order directing Detroit Edison to file a report by March 15, 2004, of the accounting of the savings due to securitization and the application of those savings through December 2003. In addition, Detroit Edison was requested to include in the report an estimate of the foregone carrying cost associated with the excess securitization savings. A report was filed on February 16, 2004 in compliance with the MPSC order.

DTE2 Accounting Application

In 2003, we began the implementation of DTE2, a Company-wide initiative to improve existing processes and to implement new core information systems, including finance, human resources, supply chain and work management. The new information systems are replacing systems that are approaching the end of their useful lives. We expect the benefits of DTE2 to include lower costs, faster business cycles, repeatable and optimized processes, enhanced internal controls, improvements in inventory management and reductions in system support costs.

In July 2004, Detroit Edison filed an accounting application with the MPSC requesting authority to capitalize and amortize DTE2 costs, consisting of computer equipment, software and development costs, as well as related training, maintenance and overhead costs. Through December 2004, we have expensed approximately $20 million of training, maintenance and overhead costs pending MPSC action on our application. Detroit Edison is proposing a 15-year amortization period for the costs, exclusive of the computer equipment costs.

Power Supply Cost Recovery Proceedings

2004 Plan Year – An MPSC December 2003 order resumed the PSCR mechanism that had been suspended while rates were frozen. The order authorized a new PSCR factor for all customers effective January 1, 2004. The MPSC's February 2004 interim order provided for a credit of 1.05 mills per kWh compared to a 2.04 mills per kWh charge previously in effect. Detroit Edison will file a 2004 PSCR reconciliation case by March 31, 2005.

2005 Plan Year – In September 2004, Detroit Edison filed its 2005 PSCR plan case seeking approval of a levelized PSCR factor of 1.82 mills per kWh above the amount included in base rates. In December 2004, Detroit Edison filed revisions to its 2005 PSCR plan case in accordance with the November 2004 MPSC rate order. The revised filing seeks approval of a levelized PSCR factor of up to 0.48 mills per kWh above the new base rates established in the final electric rate order. Included in the factor are power supply costs, transmission expenses and NOx emission allowance costs. Detroit Edison self-implemented a factor of a negative 2.00 mills per kWh on January 1, 2005. The Michigan Attorney General has filed a motion for summary disposition of this proceeding based on arguments that the PSCR statute requires a fixed 48-month PSCR factor. We cannot predict the nature or timing of actions the MPSC will take on this motion.

Transmission Proceedings

On November 18, 2004, a FERC order approved a transmission pricing structure to facilitate seamless trading of electricity between MISO and the PJM Interconnection. The pricing structure eliminates layers of transmission charges between the two regional transmission organizations. The FERC noted that the new pricing structure may result in transmission owners facing abrupt revenue shifts. To facilitate the transition to the new pricing structure, the FERC authorized a Seams Elimination Cost Adjustment (SECA), effective from December 2004 through March 2006. Under MISO's filing with the FERC, Detroit Edison's SECA obligation would be $2.2 million per month from December 2004 through March 2005. Detroit Edison has estimated that the SECA charge for the April 2005 through March 2006 period will be approximately $1 million per month. On December 20, 2004, Detroit Edison filed a request for rehearing with the FERC which states, among other things, that SECA is retroactive ratemaking and is unlawful under the Federal Power Act. Under the MPSC's November 2004 final rate order, transmission expenses are recoverable through the PSCR mechanism. Therefore, SECA charges, if ultimately imposed, should not have a financial impact to Detroit Edison.

Gas Rate Case

Rate Request – In September 2003, MichCon filed an application with the MPSC for an increase in service and distribution charges (base rates) for its gas sales and transportation customers. The filing requests an overall increase in base rates of $194 million per year (approximately 7% increase, inclusive of gas costs), beginning January 1, 2005. MichCon requested that the MPSC increase base rates by $154 million per year on an interim basis by April 1, 2004.

MPSC Interim Rate Order – In September 2004, the MPSC issued an order granting interim rate relief to MichCon in the amount of $35 million. The interim rate order was based on a 50% debt and 50% equity capital structure, and an 11.5% rate of return on common equity. Amounts collected are subject to a potential refund pending a final order in this rate case.

MPSC Staff Recommendation on Final Rate Relief – The Staff has recommended a $76 million increase in base rates compared to MichCon's requested base rate relief of $194 million. The Staff also supports a provision, proposed by MichCon, that would allow MichCon to recover or refund 90% of uncollectible accounts receivable expense above or below the amount that is reflected in base rates. In addition, the Staff proposed a 50% debt and 50% equity capital structure utilizing a reduced rate of return on common equity of 11%. MichCon's current allowed rate of return on common equity is 11.5%.

MPSC Proposal for Decision (PFD) – The Administrative Law Judge (ALJ) issued a PFD on MichCon's rate request on December 10, 2004. The PFD recommends an increase in base rates of $60 million. The PFD supports the Staff's recommendations for capital structure, rate of return on common equity and for the proposed reconciliation of uncollectible accounts receivable. MichCon expects a final order in the first quarter of 2005.

Gas Industry Restructuring

In December 2001, the MPSC approved MichCon's application for a voluntary, expanded permanent gas Customer Choice program, which replaced the experimental program that expired in March 2002. The number of customers eligible to participate in the gas Customer Choice program increased over a three-year period. Effective April 2004, all of MichCon's 1.2 million customers could elect to participate in the Customer Choice program, thereby purchasing their gas from suppliers other than MichCon. The MPSC also approved the use of deferred accounting for the recovery of implementation costs of the gas Customer Choice program. As of December 2004, approximately 111,000 customers are participating in the gas Customer Choice program.

Gas Cost Recovery Proceedings

2002 Plan Year – In December 2001, the MPSC issued an order that permitted MichCon to implement GCR factors up to $3.62 per thousand cubic feet (Mcf) for January 2002 billings and up to $4.38 per Mcf for the remainder of 2002. The order also allowed MichCon to recognize a regulatory asset of approximately $14 million representing the difference between the $4.38 factor and the $3.62 factor for volumes that were unbilled at December 31, 2001. The regulatory asset is subject to the 2002 GCR reconciliation process. In March 2003, the MPSC issued an order in MichCon's 2002 GCR plan case. The MPSC ordered MichCon to reduce its gas cost recovery expenses by $26.5 million for purposes of calculating the 2002 GCR factor due to MichCon's decision to utilize storage gas during 2001 that resulted in a gas inventory decrement for the 2001 calendar year.

Although we recorded a $26.5 million reserve in 2003 to reflect the impact of this order, a final determination of actual 2002 revenue and expenses including any disallowances or adjustment, will be decided in MichCon's 2002 GCR reconciliation case that was filed with the MPSC in February 2003. The Staff and various intervening parties in this proceeding are seeking to have the MPSC disallow an additional $26 million, representing unbilled revenues at December 2001. One party has also proposed the disallowance of half of an $8 million payment made to settle Enron bankruptcy issues. The other parties to the case have recommended that the Enron bankruptcy settlement be addressed in the 2003 GCR reconciliation case. An MPSC Administrative Law Judge has recommended disallowances of $26.5 million related to the use of storage gas in 2001 and $26 million related to the December 2001 unbilled issue, and recommended that the $8 million related to the Enron issue be addressed in the 2003 GCR reconciliation case. We have included this item in our testimony in the 2003 GCR reconciliation filed in February 2004. The Staff has recommended that MichCon be allowed to recover the entire $8 million related to the Enron issue. A final order in this proceeding is expected in 2005. In addition, we filed an appeal of the March 2003 MPSC order with the Michigan Court of Appeals. In November 2004, the Michigan Court of Appeals denied the appeal.

2003 Plan Year – In July 2003, the MPSC approved an increase in MichCon's 2003 GCR rate to a maximum of $5.75 per Mcf for the billing months of August 2003 through December 2003. MichCon's 2003 GCR reconciliation case was filed with the MPSC in February 2004. In November 2004, the ALJ issued a PFD in the 2003 reconciliation case. The ALJ recommended that MichCon recover the full $8 million related to the Enron issue since MichCon had reason to believe at that time that cancellation of the contract was in the best interests of customers and since customers ultimately realized a benefit from the cancellation. The ALJ agreed with the MPSC Staff that a $2 million accounting adjustment related to exchange gas be disallowed.

2004 Plan Year – In September 2003, MichCon filed its 2004 GCR plan case proposing a maximum GCR factor of $5.36 per Mcf. MichCon agreed to switch from a calendar year to an operational year as a condition of its settlement in the 2003 GCR plan case. The operational GCR year would run from April to March of the following year. To accomplish the switch, the 2004 GCR plan case reflects a 15-month transitional period, January 2004 through March 2005. Under the transition proposal, MichCon would file two reconciliations pertaining to the transition period; one addressing the January 2004 to March 2004 period, the other addressing the remaining April 2004 to March 2005 period. The plan also proposes a quarterly GCR ceiling price adjustment mechanism. This mechanism allows MichCon to increase the maximum GCR factor to compensate for increases in market prices, thereby reducing the possibility of a GCR under-recovery. Due to the sustained increase in market prices for natural gas, in June 2004 the MPSC approved a temporary increase in the maximum GCR factor and a contingent factor which resulted in a new temporary maximum factor of $6.62 per Mcf, effective from July 1, 2004 until the MPSC issues its final order in this case. As of December 31, 2004, MichCon has accrued a $55 million regulatory asset representing the under-recovery of actual gas costs incurred in 2004, and the 2003 and 2002 GCR under-recovery.

2005-2006 Plan Year – In December 2004, MichCon filed its 2005-2006 GCR plan case proposing a maximum GCR factor of $7.99 per Mcf. The plan includes a quarterly GCR ceiling price adjustment mechanism. This mechanism allows MichCon to increase the maximum GCR factor to compensate for increases in market prices, thereby reducing the possibility of a GCR under-recovery.

Minimum Pension Liability

In December 2002, we recorded an additional minimum pension liability as required under SFAS No. 87, with offsetting amounts to an intangible asset and other comprehensive income. During 2003, the MPSC Staff provided an opinion that the MPSC's traditional rate setting process allowed for the recovery of pension costs as measured by SFAS No. 87. Based on the MPSC Staff opinion, management believes that it will be allowed to recover in rates the minimum pension liability associated with its utility operations. In 2004 and 2003, we reclassified approximately $605 million ($393 million net of tax) and $585 million ($380 million net of tax), respectively, of other comprehensive loss associated with the minimum pension liability to a regulatory asset (Note 14).

Other

We are unable to predict the outcome of the regulatory matters discussed herein. Resolution of these matters is dependent upon future MPSC orders, which may materially impact the financial position, results of operations and cash flows of the Company.

NOTE 5 - NUCLEAR OPERATIONS

General

Fermi 2, our nuclear generating plant, began commercial operation in 1988. Fermi 2 has a design electrical rating (net) of 1,150 megawatts. This plant represents approximately 10% of Detroit Edison's summer net rated capability. The net book balance of the Fermi 2 plant was written off at December 31, 1998, and an equivalent regulatory asset was established. In 2001, the Fermi 2 regulatory asset was securitized. See Note 4 - Regulatory Matters. Detroit Edison also owns Fermi 1, a nuclear plant that was shut down in 1972 and is currently being decommissioned. The NRC has jurisdiction over the licensing and operation of Fermi 2 and the decommissioning of Fermi 1.

Property Insurance

Detroit Edison maintains several different types of property insurance policies specifically for the Fermi 2 plant. These policies cover such items as replacement power and property damage. The Nuclear Electric Insurance Limited (NEIL) is the primary supplier of these insurance polices.

Detroit Edison maintains a policy for extra expenses, including replacement power costs necessitated by Fermi 2's unavailability due to an insured event. These policies have a 12-week waiting period and provide an aggregate $490 million of coverage over a three-year period.

Detroit Edison has $500 million in primary coverage and $2.25 billion of excess coverage for stabilization, decontamination, debris removal, repair and/or replacement of property and decommissioning. The combined coverage limit for total property damage is $2.75 billion.

For multiple terrorism losses caused by acts of terrorism not covered under the Terrorism Risk Insurance Act (TRIA) of 2002 occurring within one year after the first loss from terrorism, the NEIL policies would make available to all insured entities up to $3.2 billion, plus any amounts recovered from reinsurance, government indemnity, or other sources to cover losses.

Under the NEIL policies, Detroit Edison could be liable for maximum assessments of up to approximately $28 million per event if the loss associated with any one event at any nuclear plant in the United States should exceed the accumulated funds available to NEIL.

Public Liability Insurance

As required by federal law, Detroit Edison maintains $300 million of public liability insurance for a nuclear incident. For liabilities arising from a terrorist act outside the scope of TRIA, the policy is subject to one industry aggregate limit of $300 million. Further, under the Price-Anderson Amendments Act of 1988 (Act), deferred premium charges up to $101 million could be levied against each licensed nuclear facility, but not more than $10 million per year per facility. Thus, deferred premium charges could be levied against all owners of licensed nuclear facilities in the event of a nuclear incident at any of these facilities. The Act expired on August 1, 2002. During 2003, the U.S. Congress extended the Act for commercial nuclear facilities through December 31, 2003. However, provisions of the Act remain in effect for existing commercial reactors. Legislation to extend the Act in conjunction with comprehensive energy legislation is currently under debate in Congress. We cannot predict whether Congress will pass the legislation.

Decommissioning

The NRC has jurisdiction over the decommissioning of nuclear power plants and requires decommissioning funding based upon a formula. The MPSC and FERC regulate the recovery of costs of decommissioning nuclear power plants and both require the use of external trust funds to finance the decommissioning of Fermi 2. Rates approved by the MPSC provide for the recovery of decommissioning costs of Fermi 2. Detroit Edison is continuing to fund FERC jurisdictional amounts for decommissioning even though explicit provisions are not included in FERC rates. We believe the MPSC and FERC collections will be adequate to fund the estimated cost of decommissioning using the NRC formula.

Detroit Edison has established a restricted external trust to hold funds collected from customers for decommissioning and the disposal of low-level radioactive waste. Detroit Edison collected $38 million in 2004, $36 million in 2003 and $42 million in 2002 from customers for decommissioning and low-level radioactive waste disposal. Net unrealized investment gains of $17 million and $62 million in 2004 and 2003, respectively, and $39 million in losses in 2002, were recorded as adjustments to the nuclear decommissioning trust funds and regulatory assets. At December 31, 2004, investments in the external trust consisted of approximately 55% in publicly traded equity securities, 43% in fixed debt instruments and 2% in cash equivalents.

At December 31, 2004 and 2003, Detroit Edison had external decommissioning trust funds of $546 million and $474 million, respectively, for the future decommissioning of Fermi 2. At December 31, 2004 and 2003, Detroit Edison had an additional $18 million and $22 million in trust funds for the decommissioning of Fermi 1. At December 31, 2004 and 2003, Detroit Edison also had an external decommissioning trust fund for low-level radioactive waste disposal costs of $26 million and $22 million, respectively. It is estimated that the cost of decommissioning Fermi 2, when its license expires in 2025, will be $1.0 billion in 2004 dollars and $3.4 billion in 2025 dollars, using a 6% inflation rate. In 2001, the company began the decommissioning of Fermi 1, with the goal of removing the radioactive material and terminating the Fermi 1 license. The decommissioning of Fermi 1 is expected to be complete by 2009.

As a result of adopting SFAS No. 143, Detroit Edison recorded a retirement obligation liability for the decommissioning of Fermi 1 and 2 and reversed previously recognized decommissioning liabilities. At December 31, 2004, we have recorded a liability for the removal of the non-nuclear portion of the plants of $77 million.

Nuclear Fuel Disposal Costs

In accordance with the Federal Nuclear Waste Policy Act of 1982, Detroit Edison has a contract with the U.S. Department of Energy (DOE) for the future storage and disposal of spent nuclear fuel from Fermi 2. Detroit Edison is obligated to pay the DOE a fee of 1 mill per kWh of Fermi 2 electricity generated and sold. The fee is a component of nuclear fuel expense. Delays have occurred in the DOE's program for the acceptance and disposal of spent nuclear fuel at a permanent repository. Until the DOE is able to fulfill its obligation under the contract, Detroit Edison is responsible for the spent nuclear fuel storage. Detroit Edison estimates that existing storage capacity will be sufficient until 2007. Detroit Edison is a party in the litigation against the DOE for both past and future costs associated with the DOE's failure to accept spent nuclear fuel under the timetable set forth in the Act.

NOTE-6 JOINTLY OWNED UTILITY PLANT

Detroit Edison has joint ownership interest in two power plants, Belle River and Ludington Hydroelectric Pumped Storage. Ownership information of the two utility plants as of December 31, 2004 was as follows:

	Belle River	Ludington Hydroelectric Pumped Storage
In-service date	1984-1985	1973
Total plant capacity	1,026 MW	1,872 MW
Ownership interest	*	49 %
Investment (in Millions)	$ 1,581	$ 166
Accumulated depreciation (in Millions)	$ 740	$ 88

*Detroit Edison's ownership interest is 63% in Unit No. 1, 81% of the facilities applicable to Belle River used jointly by the Belle River and St. Clair Power Plants and 75% in common facilities used at Unit No. 2.

Belle River

The Michigan Public Power Agency (MPPA) has an ownership interest in Belle River Unit No. 1 and other related facilities. The MPPA is entitled to 19% of the total capacity and energy of the plant and is responsible for the same percentage of the plant's operation, maintenance and capital improvement costs.

Ludington Hydroelectric Pumped Storage

Consumers Energy Company has an ownership interest in the Ludington Hydroelectric Pumped Storage Plant. Consumers Energy is entitled to 51% of the total capacity and energy of the plant and is responsible for the same percentage of the plant's operation, maintenance and capital improvement costs.

NOTE-7 INCOME TAXES

We file a consolidated federal income tax return.

Total income tax expense (benefit) varied from the statutory federal income tax rate for the following reasons:

(Dollars in Millions)	2004	2003	2002
Effective federal income tax rate	**27.1 %**	(34.4)%	(16.7)%
Income before income taxes and minority interest	**$ 396**	$ 266	$ 465
Less minority interest	**(212)**	(91)	(37)
Income from continuing operations before tax	**$ 608**	$ 357	$ 502
Income tax expense at 35% statutory rate	**$ 213**	$ 125	$ 175
Section 29 tax credits	**(38)**	(241)	(250)
Investment tax credits	**(8)**	(8)	(9)
Depreciation	**(4)**	(4)	2
Employee Stock Ownership Plan dividends	**(5)**	(5)	(4)
Other, net	**7**	10	2
Income tax expense (benefit) from continuing operations	**$ 165**	$ (123)	$ (84)

The minority interest allocation reflects the adjustment to earnings to allocate partnership losses to third party owners. The tax impact of partnership earnings and losses are attributable to the partners instead of the partnerships. The minority interest allocation is therefore removed in computing income taxes associated with continuing operations.

Components of income tax expense (benefit) were as follows:

(Millions)	2004	2003	2002
Continuing Operations			
Current federal and other income tax expense	**$ 31**	$ 14	$ 135
Deferred federal income tax expense (benefit)	**134**	(137)	(219)
	165	(123)	(84)
Discontinued operations	**(4)**	61	25
Cumulative Effect of Accounting Changes	**–**	(15)	–
Total	**$ 161**	$ (77)	$ (59)

Internal Revenue Code Section 29 provides a tax credit for qualified fuels produced and sold by a taxpayer to an unrelated party during the taxable year. Our Section 29 tax credits earned but not utilized totaled $483 million and are carried forward indefinitely as alternative minimum tax credits. The majority of our tax credit properties, including all of our synfuel projects, have received private letter rulings from the Internal Revenue Service (IRS) that provide assurance as to the appropriateness of using these credits to offset taxable income, however, these tax credits are subject to IRS audit and adjustment.

We have a net operating loss carryforward of $203 million that expires in years 2018 through 2020. We do not believe that a valuation allowance is required, as we expect to utilize the loss carryforward prior to its expiration.

Deferred tax assets and liabilities are recognized for the estimated future tax effect of temporary differences between the tax basis of assets or liabilities and the reported amounts in the financial statements. Deferred tax assets and liabilities are classified as current or noncurrent according to the classification of the related assets or liabilities. Deferred tax assets and liabilities not related to assets or liabilities are classified according to the expected reversal date of the temporary differences.

Deferred tax assets (liabilities) were comprised of the following at December 31:

(Millions)	2004	2003
Property	**$ (1,193)**	$(1,124)
Securitized regulatory assets	**(778)**	(827)
Alternative minimum tax credit carryforward	**483**	497
Merger basis differences	**125**	132
Pension and benefits	**(56)**	(50)
Net operating loss	**71**	84
Other	**317**	380
	$ (1,031)	$ (908)
Deferred income tax liabilities	**$ (2,527)**	$(2,525)
Deferred income tax assets	**1,496**	1,617
	$ (1,031)	$ (908)

The IRS is currently conducting audits of our federal income tax returns for the years 1998 through 2001. In addition, one of our synfuel facilities is under audit by the IRS for 2001. Audits of four of our synfuel facilities for the years 2001 and 2002 were completed successfully during 2004. The Company accrues tax and interest related to tax uncertainties that arise due to actual or potential disagreements with governmental agencies about the tax treatment of specific items. At December 31, 2004, the Company had accrued approximately $53 million for such uncertainties. We believe that our accrued tax liabilities are adequate for all years.

NOTE-8 COMMON STOCK AND EARNINGS PER SHARE

Common Stock

In March 2004, we issued 4,344,492 shares of DTE Energy common stock, valued at $170 million. The common stock was contributed to a defined benefit retirement plan.

Under the DTE Energy Company Long-Term Incentive Plan, we grant non-vested stock awards to key employees, primarily management. At the time of grant, we record the fair value of the non-vested awards as unearned compensation, which is reflected as a reduction in common stock. The number of non-vested stock awards is included in the number of common shares outstanding; however, for purposes of computing basic earnings per share, non-vested stock awards are excluded.

Shareholders' Rights Agreement

We have a Shareholders' Rights Agreement designed to maximize shareholder value should DTE Energy be acquired. Under certain triggering events, each right entitles the holder to purchase from DTE Energy one one-hundredth of a share of Series A Junior Participating Preferred Stock of DTE Energy at a price of $90.00, subject to adjustment as provided for in the Shareholders' Rights Agreement. The rights expire in October 2007.

Earnings per Share

We report both basic and diluted earnings per share. Basic earnings per share is computed by dividing income from continuing operations by the weighted average number of common shares outstanding during the period. Diluted earnings per share assumes the issuance of potentially dilutive common shares outstanding during the period and the repurchase of common shares that would have occurred with proceeds from the assumed issuance. Diluted earnings per share assume the exercise of stock options, vesting of non-vested stock awards, and the issuance of performance share awards. A reconciliation of both calculations is presented in the following table:

(in Millions, except per share amounts)	2004	2003	2002
Basic Earnings per Share			
Income from continuing operations	$ 442.6	$ 480.4	$ 585.7
Average number of common shares outstanding	172.6	167.7	164.0
Income per share of common stock based on average number of shares outstanding	$ 2.56	$ 2.87	$ 3.57
Diluted Earnings per Share			
Income from continuing operations	$ 442.6	$ 480.4	$ 585.7
Average number of common shares outstanding	172.6	167.7	164.0
Incremental shares from stock-based awards	.7	.6	.8
Average number of dilutive shares outstanding	173.3	168.3	164.8
Income per share of common stock assuming issuance of incremental shares	$ 2.55	$ 2.85	$ 3.55

Options to purchase approximately one million shares of common stock in 2004, five million shares in 2003 and one million shares in 2002 were not included in the computation of diluted earnings per share because the options' exercise price was greater than the average market price of the common shares, thus making these options anti-dilutive. Common stock to be issued in August 2005 associated with the equity-linked securities is not included in the computation of diluted earnings per share as these shares were not dilutive (Note 9).

NOTE-9 LONG-TERM DEBT AND PREFERRED SECURITIES

Long-Term Debt

Our long-term debt outstanding and weighted average interest rates* of debt outstanding at December 31 was:

(in Millions)	2004	2003
DTE Energy Debt, Unsecured		
6.1% due 2006 to 2033	$ 1,945	$ 2,005
Detroit Edison Taxable Debt, Principally Secured		
6.1% due 2005 to 2032	1,672	1,485
Detroit Edison Tax Exempt Revenue Bonds		
5.6% due 2008 to 2032	1,145	1,175
MichCon Taxable Debt, Principally Secured		
6.2% due 2006 to 2033	785	772
Quarterly Income Debt Securities (QUIDS)		
7.5% due 2026 to 2038	385	385
Non-Recourse Debt	56	78
Other Long-Term Debt	95	106
	6,083	6,006
Less amount due within one year	(410)	(382)
	$ 5,673	$ 5,624
Securitization Bonds	$ 1,496	$ 1,585
Less amount due within one year	(96)	(89)
	$ 1,400	$ 1,496
Equity-Linked Securities	$ 178	$ 185
Trust Preferred - Linked Securities		
8.625% due 2038	$ –	$ 103
7.8% due 2032	186	186
7.5% due 2044	103	–
	$ 289	$ 289

* Weighted average interest rates as of December 31, 2004

We issued and optionally redeemed long-term debt consisting of the following:

2005

- Issued $400 million of Detroit Edison senior notes in two series, $200 million of 4.8% series due 2015 and $200 million of 5.45% series due 2035. The proceeds were used to redeem the $385 million of 7.5% Quarterly Income Debt Securities due 2026 to 2028.
- Detroit Edison redeemed $76 million of 7.5% senior notes and $100 million of 7.0% remarketed secured notes, which matured February 2005.

2004

- MCN Financing II, an unconsolidated affiliate, redeemed $100 million of 8.625% Trust Originated Preferred Securities due 2038. Accordingly, the underlying trust preferred-linked securities were also simultaneously redeemed.

- Redeemed $60 million of MCN Energy Enterprises 7.12% medium term notes.
- Issued $36 million of Detroit Edison 4-7/8% tax-exempt bonds due 2029, the proceeds of which were used to redeem $36 million of Detroit Edison 6.55% tax-exempt bonds due 2024.
- Issued $32 million of Detroit Edison 4.65% tax-exempt bonds due in 2028, the proceeds of which were used to redeem the following Detroit Edison tax-exempt issues: $11.5 million of 6.05% bonds due 2023, $7.5 million of 5.875% bonds due 2024, and $13 million of 6.45% bonds due 2024.
- DTE Energy Trust II, an unconsolidated affiliate, issued an aggregate of $100 million of 7.50% Trust Originated Preferred Securities. The proceeds from the issuance were loaned to DTE Energy in exchange for debt securities with essentially the same terms as the related preferred securities.
- Issued $250 million of DTE Energy floating rate notes due in 2007. The floating rate is based on 3 month LIBOR plus 0.95%. These notes may be called at par in June 2005. The proceeds were used to repay short-term borrowings incurred in connection with the June 2004 redemption of $250 million DTE Energy 6.0% senior notes.
- Issued $200 million of Detroit Edison 5.40% senior notes due in 2014. The proceeds were used to repay short-term borrowings and for general corporate purposes.
- Issued $120 million of MichCon 5.0% senior notes due in 2019. The proceeds were used to redeem the following two issues: $52 million of 6.85% senior notes due 2038 and $55 million of 6.85% senior notes due 2039.

2003

- Issued $400 million of DTE Energy 6-3/8% senior notes maturing in April 2033. In conjunction with this issuance, DTE Energy exchanged $100 million principal amount of existing DTE Enterprises, Inc. debt due April 2008. The exchange premium and other costs associated with the original debt were deferred and are being amortized to interest expense over the term of the new debt.
- Redeemed $100 million of DTE Energy 6.17% Remarketed Notes maturing in 2038.
- Issued $49 million of Detroit Edison 5.5% tax exempt bonds maturing in 2030.
- Redeemed $49 million of Detroit Edison 6.55% tax-exempt bonds maturing in 2024.
- Issued $200 million of MichCon 5.7% senior notes maturing in March 2033.
- Redeemed $314 million of Detroit Edison taxable debt with an average interest rate of 7.4% and maturities from 2003-2023.
- Redeemed $34 million of Detroit Edison 6.875% tax-exempt bonds maturing in 2022.

In the years 2005 - 2009, our long-term debt maturities are $507 million, $680 million, $597 million, $455 million and $361 million, respectively.

Remarketable Securities

At December 31, 2004, $175 million of notes of Detroit Edison and MichCon were subject to periodic remarketings. The $100 million scheduled to remarket in February 2005 was optionally redeemed by Detroit Edison, and no remarketings will take place in 2005. We direct the remarketing agents to remarket these securities at the lowest interest rate necessary to produce a par bid. In the event that a remarketing fails, we would be required to purchase the securities.

Quarterly Income Debt Securities (QUIDS)

Detroit Edison had three series of QUIDS outstanding at December 31, 2004. Detroit Edison redeemed all of its outstanding QUIDS on March 4, 2005.

Equity-Linked Securities

In June 2002, DTE Energy issued 6.9 million equity security units with gross proceeds from the issuance of $172.5 million. An equity security unit consists of a stock purchase contract and a senior note of DTE Energy. Under the stock purchase contracts, we will sell, and equity security unit holders must buy, shares of DTE Energy common stock in August 2005 for $172.5 million. The issue price per share and the exact number of common shares to be sold is dependent on the market value of a share in August 2005. The issue price will be not less than $43.25 or more than $51.90 per common share, with the corresponding number of shares issued of not more than 4.0 million or less than 3.3 million shares. We are also obligated to pay the security unit holders a quarterly contract adjustment payment at an annual rate of 4.15% of the stated amount until the purchase contract settlement date. We recorded the present value of the contract adjustment payments of $26 million in long-term debt with an offsetting reduction in shareholders' equity. The liability is reduced as the contract adjustment payments are made.

Each senior note has a stated value of $25, pays an annual interest rate of 4.60% and matures in August 2007. The senior notes are pledged as collateral to secure the security unit holders' obligation to purchase DTE Energy common stock under the stock purchase contracts. The security unit holders may satisfy their obligations under the stock purchase contracts by allowing the senior notes to be remarketed with proceeds being paid to DTE Energy as consideration for the purchase of stock under the stock purchase contracts. Alternatively, holders may choose to continue holding the senior notes and use cash as consideration for the purchase of stock under the stock purchase contracts.

Net proceeds from the equity security unit issuance totaled $167 million. Expenses incurred in connection with this issuance totaled $5.6 million and were allocated between the senior notes and the stock purchase contracts. The amount allocated to the senior notes was deferred and will be recognized as interest expense over the term of the notes. The amount allocated to the stock purchase contracts was charged to equity.

Trust Preferred-Linked Securities

DTE Energy has interests in various unconsolidated trusts that were formed for the sole purpose of issuing preferred securities and lending the gross proceeds to us. The sole assets of the trusts are debt securities of DTE Energy with terms similar to those of the related preferred securities. Payments we make are used by the trusts to make cash distributions on the preferred securities it has issued.

We have the right to extend interest payment periods on the debt securities. Should we exercise this right, we cannot declare or pay dividends on, or redeem, purchase or acquire, any of our capital stock during the deferral period.

DTE Energy has issued certain guarantees with respect to payments on the preferred securities. These guarantees, when taken together with our obligations under the debt securities and related indenture, provide full and unconditional guarantees of the trusts' obligations under the preferred securities.

Financing costs for these issuances were paid for and deferred by DTE Energy. These costs are being amortized using the straight-line method over the estimated lives of the related securities.

Cross Default Provisions

Substantially all of the net utility properties of Detroit Edison and MichCon are subject to the lien of mortgages. Should Detroit Edison or MichCon fail to timely pay their indebtedness under these mortgages, such failure will create cross defaults in the indebtedness of DTE Energy Corporate.

Preferred and Preference Securities – Authorized and Unissued

At December 31, 2004, DTE Energy had 5 million shares of preferred stock without par value authorized, with no shares issued. Of such amount, 1.5 million shares are reserved for issuance in accordance with the Shareholders' Rights Agreement.

At December 31, 2004, Detroit Edison had approximately 6.75 million shares of preferred stock with a par value of $100 per share and 30 million shares of preference stock with a par value of $1 per share authorized, with no shares issued.

At December 31, 2004, MichCon had 7 million shares of preferred stock with a par value of $1 per share and 4 million shares of preference stock with a par value of $1 per share authorized, with no shares issued.

NOTE-10 SHORT-TERM CREDIT ARRANGEMENTS AND BORROWINGS

In May 2004, DTE Energy entered into a $375 million two-year unsecured revolving credit facility with a group of banks to be utilized for general corporate borrowings. DTE Energy had approximately $148 million of letters of credit outstanding against this facility at December 31, 2004. This agreement requires the company to maintain a debt to total capitalization ratio of no more than .65 to 1 and an "earnings before interest, taxes, depreciation and amortization" (EBITDA) to interest ratio of no less than 2 to 1. DTE Energy is currently in compliance with these financial covenants.

In October 2004, DTE Energy entered into a $525 million, five-year unsecured revolving credit facility and lowered its existing three-year revolving credit facility from $350 million to $175 million. Detroit Edison and MichCon also entered into similar revolving credit facilities. Detroit Edison entered into a $206.25 million, five-year facility and lowered its three-year facility from $137.5 million to $68.75 million. MichCon entered into a $243.75 million, five-year facility and lowered its three-year facility from $162.5 million to $81.25 million. The five-year facilities replace the October 2003 364-day facilities, which expired. The three-year revolving credit facilities expire in October 2006. The five- and three-year credit facilities are with a syndicate of banks and may be utilized for general corporate borrowings, but primarily are intended to provide liquidity support for each of the Companies' commercial paper programs. Borrowings under the facilities will be available at prevailing short-term interest rates. The agreements require each of the Companies to maintain a debt to total capitalization ratio of no more than .65 to 1 and an EBITDA to interest ratio of no less than 2 to 1. The Companies are currently in compliance with these financial covenants. Should either Detroit Edison or MichCon have delinquent debt obligations of at least $25 million to any creditor, such delinquency will be considered a default under DTE Energy's credit agreements.

As of December 31, 2004, we had outstanding commercial paper of $402 million and other short-term borrowings of $1 million.

Detroit Edison also has a $200 million short-term financing agreement secured by customer accounts receivable. This agreement contains certain covenants related to the delinquency of accounts receivable. Detroit Edison is currently in compliance with these covenants. We had no balances outstanding under this financing agreement at December 31, 2004.

The weighted average interest rates for short-term borrowings were 2.4% and 1.9% at December 31, 2004 and 2003, respectively.

NOTE-11 CAPITAL AND OPERATING LEASES

Lessee – We lease various assets under capital and operating leases, including coal cars, a gas storage field, office buildings, a warehouse, computers, vehicles and other equipment. The lease arrangements expire at various dates through 2029. Portions of the office buildings are subleased to tenants.

Future minimum lease payments under non-cancelable leases at December 31, 2004 were:

(in Millions)	Capital Leases	Operating Leases
2005	$ 11	$ 64
2006	13	56
2007	10	47
2008	11	40
2009	11	38
Thereafter	38	378
Total minimum lease payments	94	$ 623
Less imputed interest	(21)	
Present value of net minimum lease payments	73	
Less current portion	(7)	
Non-current portion	$ 66	

Total minimum lease payments for operating leases have not been reduced by future minimum sublease rentals totaling $6 million under non-cancelable subleases expiring at various dates to 2020.

Rental expense for operating leases was $75 million in 2004, $73 million in 2003 and $40 million in 2002.

Lessor – MichCon leases a portion of its pipeline system to the Vector Pipeline Partnership through a capital lease contract that expires in 2020, with renewal options extending for five years. The components of the net investment in the capital lease at December 31, 2004, were as follows:

(in Millions)	
2005	$ 9
2006	9
2007	9
2008	9
2009	9
Thereafter	98
Total minimum future lease receipts	143
Residual value of leased pipeline	40
Less unearned income	(101)
Net investment in capital lease	82
Less current portion	(1)
	$ 81

NOTE-12 FINANCIAL AND OTHER DERIVATIVE INSTRUMENTS

We comply with SFAS No. 133, *"Accounting for Derivative Instruments and Hedging Activities,"* as amended by SFAS No. 138 and SFAS No. 149. Listed below are important SFAS No. 133 requirements:

- All derivative instruments must be recognized as assets or liabilities and measured at fair value, unless they meet the normal purchases and sales exemption.
- The accounting for changes in fair value depends upon the purpose of the derivative instrument and whether it is designated as a hedge and qualifies for hedge accounting.
- Special accounting is allowed for a derivative instrument qualifying as a hedge and designated as a hedge for the variability of cash flow associated with a forecasted transaction. Gain or loss associated with the effective portion of the hedge is recorded in other comprehensive income. The ineffective portion is recorded to earnings. Amounts recorded in other comprehensive income will be reclassified to net income when the forecasted transaction affects earnings. If a cash flow hedge is discontinued because it is likely the forecasted transaction will not occur, net gains or losses are immediately recorded to earnings.
- Special accounting is also allowed for a derivative instrument qualifying as a hedge and designated as a hedge of the changes in fair value of an existing asset, liability or firm commitment. Gain or loss on the hedging instrument is recorded into earnings. An offsetting loss or gain on the underlying asset, liability or firm commitment is also recorded to earnings.

Our primary market risk exposure is associated with commodity prices, credit, interest rates and foreign currency. We have risk management policies to monitor and decrease market risks. We use derivative instruments to manage some of the exposure. Except for the activities of the Energy Marketing & Trading segment, we do not hold or issue derivative instruments for trading purposes. The fair value of all derivatives is shown as "assets or liabilities from risk management and trading activities" in the consolidated statement of financial position.

Commodity Price Risk

Utility Operations

Detroit Edison – Detroit Edison generates, purchases, distributes and sells electricity. Detroit Edison uses forward energy, capacity, and futures contracts to manage changes in the price of electricity and fuel. These derivatives are designated as cash flow hedges or meet the normal purchases and sales exemption and are therefore accounted for under the accrual method. There were no commodity price risk cash flow hedges for utility operations at December 31, 2004.

MichCon – MichCon purchases, stores, transmits and distributes and sells natural gas. MichCon has fixed-priced contracts for portions of its expected gas supply requirements through 2005. These contracts are designated and qualify for the normal purchases and sales exemption and are therefore accounted for under the accrual method.

Commodity price risk associated with our utilities is limited due to the PSCR and GCR mechanisms (Note 1).

Non-Utility Operations

Energy Marketing & Trading – Energy Marketing and Trading markets and trades wholesale electricity and natural gas physical products, trades financial instruments, and provides risk management services utilizing energy commodity derivative instruments. Forwards, futures, options and swap agreements are used to manage exposure to the risk of market price and volume fluctuations on its operations. These derivatives are accounted for by recording changes in fair value to earnings, usually as adjustments to operating revenues or fuel, purchased power and gas expense. This fair value accounting better aligns financial reporting with the way the business is managed and its performance measured.

Energy Marketing & Trading experiences earnings volatility as a result of its gas inventory and other non-derivative assets that do not qualify for fair value accounting under U. S. generally accepted accounting principles. Although the risks associated with these asset positions are substantially offset, requirements to fair value the underlying derivatives result in unrealized gains and losses being recorded to earnings that eventually reverse upon settlement.

Energy Services and Biomass – Our Energy Services and Biomass businesses generate Section 29 tax credits. Additionally, through December 2004, Energy Services has sold majority interests in eight of its nine synthetic fuel production plants. Proceeds from the sales are contingent upon production levels, the production qualifying for Section 29 tax credits, and the value of such credits. Section 29 tax credits are subject to phase out if domestic crude oil prices reach certain levels. See Note 13 for further discussion.

To manage our exposure in 2005 to the risk of an increase in oil prices that could reduce synfuel sales proceeds, we entered into a series of derivative contracts covering a specified number of barrels of oil. The derivatives, coupled with other contracts, economically hedge approximately 65% of our 2005 synfuel cash flow exposure. The derivative contracts involve purchased and written call options that provide for net cash settlement at expiration based on the full year 2005 average New York Mercantile Exchange (NYMEX) trading price of oil in relation to the strike price of each option. If the average NYMEX price of oil in 2005 is less than approximately $56 per barrel, the derivatives will yield no payment. If the average NYMEX price of oil exceeds approximately $56 per barrel, the derivatives will yield a payment equal to the excess of the average NYMEX price over $56 per barrel, multiplied by the number of barrels covered, up to a maximum price of approximately $68 per barrel. The agreements do not qualify for hedge accounting and, as a result, changes in the fair value of the options are recorded currently in earnings. The fair value changes are recorded as adjustments to the gain from selling interests in synfuel facilities and therefore included in the "Asset gains and losses, net" line item in the consolidated statement of operations.

Gas Production – Our Gas Production business is engaged in natural gas exploration, development and production. We use derivative contracts to manage changes in the price of natural gas. These derivatives are designated as cash flow hedges. Amounts recorded in other comprehensive loss will be reclassified to earnings as the related forecasted production affects earnings through 2013. In 2005, we estimate reclassifying $35 million of losses to earnings.

Credit Risk

Our utility and non-utility businesses are exposed to credit risk if customers or counterparties do not comply with their contractual obligations. We maintain credit policies that significantly minimize overall credit risk. These policies include an evaluation of potential customers' and counterparties' financial condition, credit rating, collateral requirements or other credit enhancements such as letters of credit or guarantees. We use standardized agreements that allow the netting of positive and negative transactions associated with a single counterparty.

Interest Rate Risk

We use interest rate swaps, treasury locks and other derivatives to hedge the risk associated with interest rate market volatility. In 2004 and 2000, we entered into a series of interest rate derivatives to limit our sensitivity to market interest rate risk associated with the issuance of long-term debt. Such instruments were designated as cash flow hedges. We subsequently issued long-term debt and terminated these hedges at a cost that is included in other comprehensive loss. Amounts recorded in other comprehensive loss will be reclassified to interest expense as the related interest affects earnings through 2030. In 2005, we estimate reclassifying $6 million of losses to earnings.

Foreign Currency Risk

Energy Marketing and Trading has foreign currency forward contracts to hedge fixed Canadian dollar commitments existing under power purchase and sale contracts and gas transportation contracts. We entered into these contracts to mitigate any price volatility with respect to fluctuations of the Canadian dollar relative to the U.S. dollar. Certain of these contracts are designated as cash flow hedges with changes in fair value recorded to other comprehensive income. Amounts recorded to other comprehensive income are classified to operating revenues or fuel, purchased power and gas expense when the related hedged item affects earnings.

Fair Value of Other Financial Instruments

The fair value of financial instruments is determined by using various market data and other valuation techniques. The table below shows the fair value relative to the carrying value for long-term debt securities. The carrying value of certain other financial instruments, such as notes payable, customer deposits and notes receivable approximate fair value and are not shown.

	2004		2003	
	Fair Value	**Carrying Value**	Fair Value	Carrying Value
Long-Term Debt	**$8.5 billion**	**$ 8.0 billion**	$ 8.5 billion	$ 7.9 billion

NOTE-13 COMMITMENTS AND CONTINGENCIES

Synthetic Fuel Operations

We partially or wholly own nine synthetic fuel production facilities. Synfuel facilities chemically change coal, including waste and marginal coal, into a synthetic fuel as determined under applicable IRS rules. Section 29 of the Internal Revenue Code provides tax credits for the production and sale of solid synthetic fuels produced from coal. To qualify for the Section 29 tax credits, the synthetic fuel must meet three primary conditions: (1) there must be a significant chemical change in the coal feedstock, (2) the product must be sold to an unaffiliated entity, and (3) the production facility must have been placed in service before July 1, 1998. In addition to meeting the qualifying conditions, a taxpayer must have sufficient taxable income to earn the Section 29 tax credits.

In-Service Date – During July 2004, several unaffiliated companies announced that they have been notified that the IRS intends to challenge the placed in service dates for some of their synfuel facilities. If the IRS ultimately prevails, Section 29 credits claimed by these companies would be disallowed. The placed in-service issue is fact-driven and specific to each facility. The in-service dates for eight of our nine synfuel plants have been favorably reviewed by the IRS in conjunction with issuing determination letters and/or recently completed audits. We believe all nine of our synthetic fuel plants meet the required in-service condition.

Through December 31, 2004, we have generated and recorded approximately $512 million in synfuel tax credits.

Oil Prices – To reduce U.S. dependence on imported oil, the Internal Revenue Code provides Section 29 tax credits as an incentive for taxpayers to produce fuels from alternative sources. This incentive is not deemed necessary if the price of oil increases and provides a natural market for these fuels. As such, the tax credit in a given year is reduced if the Reference Price of oil within that year exceeds a threshold price. The Reference Price of a barrel of oil is an estimate of the annual average wellhead price per barrel for domestic crude oil, which in recent years has been $3 - $4 lower than the NYMEX price for light, sweet crude oil. The threshold price at which the credit begins to be reduced was set in 1980 and is adjusted annually for inflation. For 2004, we estimate that the threshold price at which the tax credit would have begun to be reduced was $51.34 and would have been completely phased out if the Reference Price reached $64.45. The Reference Price of oil is estimated to be $37.61 for 2004. We also estimate that the 2005 average wellhead price per barrel of oil would have to exceed approximately $52.37 per barrel to begin phase out and exceed approximately $65.74 per barrel to eliminate the credits. We cannot predict with any accuracy the future price of a barrel of oil.

Numerous recent events have increased domestic crude oil prices, including terrorism, storm-related supply disruptions and worldwide demand. If the credit is reduced or eliminated in future years, our financial statements would be negatively impacted. We continue to evaluate the current volatility in oil prices and alternatives available to mitigate our exposure to oil prices as part of our synfuel-related risk management strategy. To manage our exposure to oil prices in 2005, we entered into oil-related derivative contracts. See Note 12 for further discussion.

Environmental

Air – The EPA issued ozone transport and acid rain regulations and, in December 2003, proposed additional emission regulations relating to ozone, fine particulate and mercury air pollution. The new rules have led to additional controls on fossil-fueled power plants to reduce nitrogen oxide, sulfur dioxide, carbon dioxide and particulate emissions. To comply with these new controls, Detroit Edison has spent approximately $580 million through December 2004, and estimates that it will spend up to $100 million in 2005 and incur from $700 million to $1.3 billion of additional future capital expenditures over the next five to eight years to satisfy both the existing and proposed new control requirements. Under the June 2000 Michigan restructuring legislation, beginning January 1, 2004, annual return of and on this capital expenditure, in excess of current depreciation levels, could be deferred in ratemaking, until after the expiration of the rate cap period, presently expected to end on December 31, 2005 upon MPSC authorization. Under PA 141 and the MPSC's November 2004 final rate order, we believe that prudently incurred capital expenditures, in excess of current depreciation levels, are recoverable in rates.

Water – Detroit Edison is required to examine alternatives for reducing the environmental impacts of the cooling water intake structures at several of its facilities. Based on the results of the studies to be conducted over the next several years, Detroit Edison may be required to install additional control technologies to reduce the impacts of the intakes. It is estimated that we will incur up to $50 million over the next five to seven years in additional capital expenditures for Detroit Edison.

Contaminated Sites – Prior to the construction of major interstate natural gas pipelines, gas for heating and other uses was manufactured locally from processes involving coal, coke or oil. Enterprises (MichCon and Citizens) owns, or previously owned, 18 such former manufactured gas plant (MGP) sites. During the mid-1980's, Enterprises conducted preliminary environmental investigations at former MGP sites, and some contamination related to the by-products of gas manufacturing was discovered at each site. The existence of these sites and the results of the environmental investigations have been reported to the MDEQ.

Enterprises is remediating eight of the former MGP sites and conducting more extensive investigations at five other former MGP sites. Enterprises received MDEQ closure of one site, and a determination that it is not a responsible party for three other sites. Enterprises received closure from the EPA in 2002 for one site.

In 1984, Enterprises established a $12 million reserve for costs associated with environmental investigation and remediation activities. During 1993, MichCon received MPSC approval of a cost deferral and rate recovery mechanism for investigation and remediation costs incurred at former MGP sites in excess of this reserve. Enterprises employed outside consultants to evaluate remediation alternatives for these sites, to assist in estimating its potential liabilities and to review its archived insurance policies. As a result of these studies, Enterprises accrued an additional liability and a corresponding regulatory asset of $35 million during 1995. In early December 2004, Enterprises retained multiple environmental consultants to estimate the projected cost to remediate each MGP facility. The results of the evaluation indicated that the MGP reserve should be set at $24 million.

During 2004, Enterprises spent approximately $2 million investigating and remediating these former MGP sites. At December 31, 2004, the reserve balance was $24 million of which $4.5 million was classified as current. Any significant change in assumptions, such as remediation techniques, nature and extent of contamination and regulatory requirements, could impact the estimate of remedial action costs for the sites and, therefore, have an effect on the Company's financial position and cash flows. However, we anticipate the cost deferral and rate recovery mechanism approved by the MPSC will prevent environmental costs from having a material adverse impact on our results of operations.

Detroit Edison conducted remedial investigations at contaminated sites, including two former MGP sites, the area surrounding an ash landfill and several underground and aboveground storage tank locations. The findings of these investigations indicated that the cost to remediate these sites is approximately $8 million, which is expected to be incurred over the next several years. As a result of the investigation, Detroit Edison accrued an $8 million liability during 2004.

Guarantees

In certain circumstances we enter into contractual guarantees. We may guarantee another entity's obligation in the event it fails to perform. We may provide guarantees in certain indemnification agreements. Finally, we may provide indirect guarantees of the indebtedness of others. Below are the details of specific material guarantees we currently provide. Our other guarantees are not individually material and total approximately $40 million at December 31, 2004.

Sale of Interests in Synfuel Facilities

We have provided certain guarantees and indemnities in conjunction with the sales of interests in our synfuel facilities. The guarantees cover general commercial, environmental and tax-related exposure and will survive until 90 days after expiration of all applicable statute of limitations, or indefinitely, depending on the nature of the guarantee. We estimate that our maximum liability under these guarantees at December 31, 2004 totals $905 million.

Parent Company Guarantee of Subsidiary Obligations

We have issued guarantees for the benefit of various non-utility subsidiary transactions. In the event that DTE Energy's credit rating is downgraded below investment grade, certain of these guarantees would require us to post cash or letters of credit valued at approximately $356 million at December 31, 2004. This estimated amount fluctuates based upon the provisions and maturities of the underlying agreements.

Personal Property Taxes

Prior to 1999, Detroit Edison, MichCon and other Michigan utilities asserted that Michigan's valuation tables result in the substantial overvaluation of utility personal property. Valuation tables established by the Michigan State Tax Commission (STC) are used to determine the taxable value of personal property based on the property's age. In November 1999, the STC approved new valuation tables that more accurately recognize the value of a utility's personal property. The new tables became effective in 2000 and are currently used to calculate property tax expense. However, several local taxing jurisdictions have taken legal action attempting to prevent the STC from implementing the new valuation tables and have continued to prepare assessments based on the superseded tables. The legal actions regarding the appropriateness of the new tables were before the Michigan Tax Tribunal (MTT) which, in April 2002, issued its decision essentially affirming the validity of the STC's new tables. In June 2002, petitioners in the case filed an appeal of the MTT's decision with the Michigan Court of Appeals. In January 2004, the Michigan Court of Appeals upheld the validity of the new tables. With no further appeal by the petitioners available, the MTT began to schedule utility personal property valuation cases for Prehearing General Calls. Detroit Edison and MichCon have filed motions and the MTT agreed to place their cases in abeyance pending the conclusion of settlement negotiations being conducted by State of Michigan Treasury officials. On February 14, 2005, MTT issued a scheduling order that lifts the prior abeyances in a significant number of Detroit Edison and MichCon appeals. The scheduling order sets litigation calendars for these cases extending into mid-2006.

Detroit Edison and MichCon continue to record property tax expense based on the new tables. Detroit Edison and MichCon will continue through settlement or litigation to seek to apply the new tables retroactively and to ultimately resolve the pending tax appeals related to 1997 through 1999. This is a solution supported by the STC in the past. To the extent that settlements cannot be achieved with the jurisdictions, litigation regarding the valuation of utility property will delay any recoveries by Detroit Edison and MichCon.

Other Commitments

Detroit Edison has an Energy Purchase Agreement to purchase steam and electricity from the Greater Detroit Resource Recovery Authority (GDRRA). Under the Agreement, Detroit Edison will purchase steam through 2008 and electricity through June 2024. In 1996, a special charge to income was recorded that included a reserve for steam purchase commitments in excess of replacement costs from 1997 through 2008. The reserve for steam purchase commitments is being amortized to fuel, purchased power and gas expense with non-cash accretion expense being recorded through 2008. We purchased $42 million of steam and electricity in 2004, $39 million in 2003 and $37 million in 2002. We estimate steam and electric purchase commitments through 2024 will not exceed $472 million. As discussed in Note 3 – Dispositions, in January 2003, we sold the steam heating business of Detroit Edison to Thermal Ventures II, LP. Due to terms of the sale, Detroit Edison remains contractually obligated to buy steam from GDRRA until 2008 and recorded an additional liability of $20 million for future commitments. Also, we have guaranteed bank loans that Thermal Ventures II, LP may use for capital improvements to the steam heating system.

In 2004, we modified our future purchase commitments under a transportation agreement with an interstate pipeline company and terminated a related long-term gas exchange (storage) agreement. Under the gas exchange agreement, we received gas from the customer during the summer injection period and redelivered the gas during the winter heating season. The agreements were at rates that were not reflective of current market conditions and had been fair valued under accounting principles generally accepted in the U.S. In 2002, the fair value of the transportation agreement was frozen when it no longer met the definition of a derivative as a result of FERC Order 637. The fair value amounts were being amortized to income over the life of the related agreements, representing a net liability of approximately $75 million as of December 31, 2003. As a result of the contract modification and termination, we recorded an adjustment to the net liability increasing 2004 earnings by $48 million, net of taxes.

At December 31, 2004, we have entered into numerous long-term purchase commitments relating to a variety of goods and services required for our business. These agreements primarily consist of fuel supply commitments and energy trading contracts. We estimate that these commitments will be approximately $7.3 billion through 2027. We also estimate that 2005 base level capital expenditures will be $1.1 billion. We have made certain commitments in connection with expected capital expenditures.

Bankruptcies

We purchase and sell electricity, gas, coal and coke from and to numerous companies operating in the steel, automotive, energy and retail industries. Several customers have filed for bankruptcy protection under Chapter 11 of the U.S. Bankruptcy Code. We have negotiated or are currently involved in negotiations with each of the companies, or their successor companies, that have filed for bankruptcy protection. We regularly review contingent matters relating to purchase and sale contracts and record provisions for amounts considered probable of loss. We believe our previously accrued amounts are adequate for probable losses. The final resolution of these matters is not expected to have a material effect on our financial statements in the period they are resolved.

Other

We are involved in certain legal, regulatory, administrative and environmental proceedings before various courts, arbitration panels and governmental agencies concerning claims arising in the ordinary course of business. These proceedings include certain contract disputes, environmental reviews and investigations, audits, inquiries from various regulators, and pending judicial matters. We cannot predict the final disposition of such proceedings. We regularly review legal matters and record provisions for claims that are considered probable of loss. The resolution of pending proceedings is not expected to have a material effect on our operations or financial statements in the period they are resolved.

See Note 4 and Note 5 for a discussion of contingencies related to Regulatory Matters and Nuclear Operations.

NOTE-14 RETIREMENT BENEFITS AND TRUSTEED ASSETS

Measurement Date

In the fourth quarter of 2004, we changed the date for actuarial measurement of our obligations for benefit programs from December 31 to November 30. We believe the one-month change of the measurement date is a preferable change as it allows time for management to plan and execute its review of the completeness and accuracy of its benefit programs results and to fully reflect the impact on its financial results. The change did not have a material effect on retained earnings as of January 1, 2004, and income from continuing operations, net income and related per share amounts for any interim period in 2004. Accordingly, all amounts reported in the following tables for balances as of December 31, 2004 are based on a measurement date of November 30, 2004. Amounts reported in tables for the year ended December 31, 2004 and for balances as of December 31, 2003 are based on a measurement date of December 31, 2003. Amounts reported in tables for the year ended December 31, 2003 are based on a measurement date of December 31, 2002.

Qualified and Nonqualified Pension Plan Benefits

We have defined benefit retirement plans for eligible represented and nonrepresented employees. The plans are noncontributory, cover substantially all employees and provide retirement benefits based on the employees' years of benefit service, average final compensation and age at retirement. Certain represented and nonrepresented employees are covered under cash balance benefits based on annual employer contributions and interest credits. Our policy is to fund pension costs by contributing the minimum amount required by the Employee Retirement Income Security Act (ERISA) and additional amounts when we deem appropriate. We do not anticipate making a contribution to our qualified pension plans in 2005.

We also maintain supplemental nonqualified, noncontributory, retirement benefit plans for selected management employees. These plans provide for benefits that supplement those provided by DTE Energy's other retirement plans.

Net pension cost (credit) includes the following components:

	Qualified Pension Plans			Nonqualified Pension Plans		
(in Millions)	2004	2003	2002	2004	2003	2002
Service Cost	**$ 58**	$ 48	$ 43	**$ 2**	$ 2	$ 1
Interest Cost	**168**	164	162	**3**	4	3
Expected Return on Plan Assets	**(216)**	(211)	(223)	**–**	–	–
Amortization of						
Net loss	**63**	38	2	**1**	1	1
Prior service cost	**8**	8	9	**–**	–	1
Net transition asset	**–**	–	(2)	**–**	–	–
Net Pension Cost (Credit)	**$ 81**	$ 47	$ (9)	**$ 6**	$ 7	$ 6

The following table reconciles the obligations, assets and funded status of the plans as well as the amounts recognized as prepaid pension cost or pension liability in the consolidated statement of financial position at December 31:

	Qualified Pension Plans		Nonqualified Pension Plans	
(in Millions)	2004	2003	2004	2003
Measurement Date	**Nov. 30**	Dec. 31	**Nov. 30**	Dec. 31
Accumulated Benefit Obligation-End of Period	**$ 2,689**	$ 2,556	**$ 54**	$ 57
Projected Benefit Obligation-Beginning of Period	**$ 2,745**	$ 2,499	**$ 59**	$ 50
Service Cost	**58**	48	**2**	2
Interest Cost	**168**	164	**3**	4
Actuarial Loss (Gain)	**76**	201	**(4)**	6
Benefits Paid	**(149)**	(159)	**(4)**	(3)
Plan Amendments	**1**	(8)	**–**	–
Projected Benefit Obligation-End of Period	**$ 2,899**	$ 2,745	**$ 56**	$ 59
Plan Assets at Fair Value-Beginning of Period	**$ 2,348**	$ 1,845	**$ –**	$ –
Actual Return on Plan Assets	**196**	440	**–**	–
Company Contributions	**170**	222	**4**	3
Benefits Paid	**(149)**	(159)	**(4)**	(3)
Plan Assets at Fair Value-End of Period	**$ 2,565**	$ 2,348	**$ –**	$ –
Funded Status of the Plans	**$ (334)**	$ (397)	**$ (56)**	$ (59)
Unrecognized				
Net loss	**1,043**	1,010	**15**	18
Prior service cost	**34**	41	**1**	3
Net Amount Recognized at Measurement Date	**743**	654	**(40)**	(38)
Company Contribution in December 2004	**–**	–	**1**	–
Net Amount Recognized -End of Period	**$ 743**	$ 654	$ (39)	$ (38)
Amount Recorded as				
Prepaid pension assets	**$ 184**	$ 181	**$ –**	$ –
Accrued pension liability	**(212)**	(287)	**(53)**	(58)
Regulatory asset	**594**	572	**11**	13
Accumulated other comprehensive loss	**139**	147	**2**	4
Intangible asset	**38**	41	**1**	3
	$ 743	$ 654	**$ (39)**	$ (38)

Assumptions used in determining the projected benefit obligation and net pension costs are listed below:

	2004	2003	2002
Projected Benefit Obligation			
Discount rate	**6.00%**	6.25%	6.75%
Annual increase in future compensation levels	**4.0%**	4.0%	4.0%
Net Pension Costs			
Discount rate	**6.25%**	6.75%	7.25%
Annual increase in future compensation levels	**4.0%**	4.0%	4.0%
Expected long-term rate of return on Plan assets	**9.0%**	9.0%	9.5%

At December 31, 2004, the benefits related to our qualified and non-qualified plans expected to be paid in each of the next five years and in the aggregate for the five fiscal years thereafter are as follows:

(in Millions)	
2005	**$ 173**
2006	**177**
2007	**182**
2008	**189**
2009	**194**
2010 - 2014	**1,091**
Total	**$ 2,006**

We employ a consistent formal process in determining the long-term rate of return for various asset classes. We evaluate input from our consultants, including their review of historic financial market risks and returns and long-term historic relationships between the asset classes of equities, fixed income and other assets, consistent with the widely accepted capital market principle that asset classes with higher volatility generate a greater return over the long-term. Current market factors such as inflation, interest rates, asset class risks and asset class returns are evaluated and considered before long-term capital market assumptions are determined. The long-term portfolio return is also established employing a consistent formal process, with due consideration of diversification, active investment management and rebalancing. Peer data is reviewed to check for reasonableness.

We employ a total return investment approach whereby a mix of equities, fixed income and other investments are used to maximize the long-term return of plan assets consistent with prudent levels of risk. The intent of this strategy is to minimize plan expenses over the long-term. Risk tolerance is established through consideration of future plan cash flows, plan funded status, and corporate financial considerations. The investment portfolio contains a diversified blend of equity, fixed income and other investments. Furthermore, equity investments are diversified across U.S. and non-U.S. stocks, growth and value investment styles, and large and small market capitalizations. Other assets such as private equity and absolute return funds are used judiciously to enhance long term returns while improving portfolio diversification. Derivatives may be used to gain market exposure in an efficient and timely manner; however, derivatives may not be used to leverage the portfolio beyond the market value of the underlying investments. Investment risk is measured and monitored on an ongoing basis through annual liability measurements, periodic asset/liability studies, and quarterly investment portfolio reviews.

Our plans' weighted-average asset allocations by asset category at December 31 were as follows:

	2004	2003
Equity Securities	**69%**	67%
Debt Securities	**26**	27
Other	**5**	6
	100%	100%

Our plans' weighted-average asset target allocations by asset category at December 31, 2004 were as follows:

Equity Securities	**65%**
Debt Securities	**28**
Other	**7**
	100%

In December 2002, we recognized an additional minimum pension liability as required under SFAS No. 87, *"Employers' Accounting for Pensions."* An additional pension liability may be required when the accumulated benefit obligation of the plan exceeds the fair value of plan assets. Under SFAS No. 87, we recorded an additional minimum pension liability, an intangible asset and other comprehensive loss. In 2003, we reclassified $572 million of other comprehensive loss related to Detroit Edison's minimum pension liability to a regulatory asset after the MPSC Staff provided an opinion that the MPSC's traditional rate setting process allowed for the recovery of pension costs as measured by SFAS No. 87. The additional minimum pension liability, regulatory asset, intangible asset and other comprehensive loss are adjusted in December of each year based on the plans' funded status.

We also sponsor defined contribution retirement savings plans. Participation in one of these plans is available to substantially all represented and nonrepresented employees. We match employee contributions up to certain predefined limits based upon eligible compensation, the employee's contribution rate and, in some cases, years of credited service. The cost of these plans was $28 million in 2004, $26 million in 2003 and $25 million in 2002.

Other Postretirement Benefits

We provide certain postretirement health care and life insurance benefits for employees who are eligible for these benefits. Our policy is to fund certain trusts to meet our postretirement benefit obligations. Separate qualified Voluntary Employees Beneficiary Association (VEBA) trusts exist for represented and nonrepresented employees.

Net postretirement cost includes the following components:

(in Millions)	2004	2003	2002
Service Cost	**$ 41**	$ 37	$ 30
Interest Cost	**92**	87	78
Expected Return on Plan Assets	**(56)**	(47)	(59)
Amortization of			
Net loss	**43**	31	3
Prior service cost	**(3)**	(3)	(1)
Net transition obligation	**8**	13	19
Net Postretirement Cost	**$ 125**	$ 118	$ 70

The following table reconciles the obligations, assets and funded status of the plans including amounts recorded as accrued postretirement cost in the consolidated statement of financial position at December 31:

(in Millions)	2004	2003
Measurement Date	**Nov. 30**	Dec. 31
Accumulated Postretirement Benefit Obligation-Beginning of Period	**$ 1,582**	$ 1,494
Service Cost	**41**	37
Interest Cost	**92**	87
Actuarial Loss	**146**	162
Plan Amendments	**7**	(126)
Benefits Paid	**(75)**	(72)
Accumulated Postretirement Benefit Obligation-End of Period	**$ 1,793**	$ 1,582
Plan Assets at Fair Value-Beginning of Period	**$ 586**	$ 537
Actual Return on Plan Assets	**53**	114
Company Contributions	**40**	–
Benefits Paid	**–**	(65)
Plan Assets at Fair Value-End of Period	**$ 679**	$ 586
Funded Status of the Plans	**$ (1,114)**	$ (996)
Unrecognized		
Net loss	**811**	705
Prior service cost	**(8)**	(27)
Net transition obligation	**58**	74
Accrued Postretirement Liability at Measurement Date	**(253)**	(244)
Company Contribution And Benefit Payments in December 2004	**(20)**	–
Accrued Postretirement Liability-End of Period	**$ (273)**	$ (244)

Assumptions used in determining the projected benefit obligation and net benefit costs are listed below:

	2004	2003	2002
Projected Benefit Obligation			
Discount rate	**6.00 %**	6.25%	6.75%
Net Benefit Costs			
Discount rate	**6.25 %**	6.75%	7.25%
Expected long-term rate of return on Plan assets	**9.0 %**	9.0%	9.5%

Benefit costs were calculated assuming health care cost trend rates beginning at 9.0% for 2005 and decreasing to 5.0% in 2010 and thereafter for persons under age 65 and decreasing from 8.0% to 5.0% for persons age 65 and over. A one-percentage-point increase in health care cost trend rates would have increased the total service cost and interest cost components of benefit costs by $20 million and increased the accumulated benefit obligation by $177 million at December 31, 2004. A one-percentage-point decrease in the health care cost trend rates would have decreased the total service and interest cost components of benefit costs by $17 million and would have decreased the accumulated benefit obligation by $157 million at December 31, 2004.

Effective 2005, we amended our postretirement health care plan to provide for some enhancements. The changes increased our expected 2005 postretirement cost by $6 million.

At December 31, 2004, the benefits expected to be paid, including prescription drug benefits, in each of the next five years and in the aggregate for the five fiscal years thereafter are as follows:

(in Millions)	
2005	**$ 97**
2006	**106**
2007	**110**
2008	**113**
2009	**120**
2010 - 2014	**665**
Total	**$ 1,211**

The process used in determining the long-term rate of return for assets and the investment approach for our other postretirement benefits plans is similar to those previously described for our qualified pension plans.

Our plans' weighted-average asset allocations by asset category at December 31 were as follows:

	2004	2003
Equity Securities	**68%**	66%
Debt Securities	**28**	30
Other	**4**	4
	100%	100%

Our plans' weighted-average asset target allocations by asset category at December 31, 2004 were as follows:

Equity Securities	**65%**
Debt Securities	**28**
Other	**7**
	100%

In December 2003, the Medicare Act was signed into law which provides for a non-taxable federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least "actuarially equivalent" to the benefit established by law. As discussed in Note 2, we adopted FSP No. 106-2 in 2004, which provides guidance on the accounting for the Medicare Act. As a result of the adoption, our accumulated postretirement benefit obligation for the subsidy related to benefits attributed to past service was reduced by approximately $95 million at January 1, 2004 and was accounted for as an actuarial gain. The effects of the subsidy reduced net periodic postretirement benefit costs by $16 million in 2004. The impact of the Medicare Act on the components of other postretirement benefit costs for the year ended December 31 was as follows:

(in Millions)	
Reduction in service cost	**$ 2**
Reduction in interest cost	**6**
Amortization of actuarial gain	**8**
Decrease in postretirement benefit cost	**$ 16**

At December 31, 2004, the gross amount of federal subsidies expected to be received in each of the next five years and in the aggregate for the five fiscal years thereafter was as follows:

(in Millions)	
2005	**$ –**
2006	**11**
2007	**11**
2008	**12**
2009	**12**
2010 - 2014	**69**
Total	**$ 115**

Grantor Trust

MichCon maintains a Grantor Trust that invests in life insurance contracts and income securities. Employees and retirees have no right, title or interest in the assets of the Grantor Trust, and MichCon can revoke the trust subject to providing the MPSC with prior notification. We account for our investment at fair value with unrealized gains and losses recorded to earnings.

NOTE-15 STOCK-BASED COMPENSATION

The DTE Energy Stock Incentive Plan permits the grant of incentive stock options, non-qualifying stock options, stock awards, performance shares and performance units. A maximum of 18 million shares of common stock may be issued under the plan. Participants in the plan include our employees and members of our Board of Directors. As of December 31, 2004, no performance units have been granted under the plan.

Options

Options are exercisable according to the terms of the individual stock option award agreements and expire 10 years after the date of the grant. The option exercise price equals the fair value of the stock on the date that the option was granted. Stock option activity was as follows:

	Number of Options	Weighted Average Exercise Price
Outstanding at December 31, 2001 (1,678,870 exercisable)	5,281,624	$ 38.51
Granted	1,334,370	$ 42.08
Exercised	(678,715)	$ 34.64
Canceled	(456,684)	$ 38.74
Outstanding at December 31, 2002 (2,285,323 exercisable)	5,480,595	$ 39.87
Granted	1,654,879	$ 40.56
Exercised	(329,528)	$ 35.88
Canceled	(152,824)	$ 42.67
Outstanding at December 31, 2003 (3,506,038 exercisable)	**6,653,122**	**$ 40.18**
Granted	**1,300,900**	**$ 39.41**
Exercised	**(891,353)**	**$ 34.94**
Canceled	**(356,000)**	**$ 43.06**
Outstanding at December 31, 2004 (3,939,939 exercisable at a weighted average exercise price of $40.52)	**6,706,669**	**$ 40.57**

The number, weighted average exercise price and weighted average remaining contractual life of options outstanding were as follows:

Range of Exercise Prices	Number of Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life
$27.62 – $38.04	649,604	$ 31.70	5.02 years
$38.60 – $42.44	4,594,837	$ 40.68	7.65 years
$42.60 – $44.54	690,950	$ 42.70	6.38 years
$45.28 – $46.74	771,278	$ 45.47	6.51 years
	6,706,669	$ 40.57	7.13 years

We account for option awards under APB Opinion 25. Accordingly, no compensation expense has been recorded for options granted. As required by SFAS No. 123, we have determined the fair value for these options at the date of grant using a Black-Scholes based option pricing model and the following assumptions:

	2004	2003	2002
Risk-free interest rate	**3.55 %**	2.93 %	5.33 %
Dividend yield	**5.23 %**	4.97 %	4.90 %
Expected volatility	**20.00 %**	20.89 %	19.79 %
Expected life	**6 years**	6 years	6 years
Fair value per option	**$4.46**	$4.78	$6.25

Stock Awards

Stock awards granted under the plan are restricted for varying periods, which are generally for three years. Participants have all rights of a shareholder with respect to a stock award, including the right to receive dividends and vote the shares. Prior to vesting in stock awards, the participant: (i) may not sell, transfer, pledge, exchange or otherwise dispose of shares; (ii) shall not retain custody of the share certificates; and (iii) will deliver to us a stock power with respect to each stock award.

The stock awards are recorded at cost that approximates fair value on the date of grant. We account for stock awards as unearned compensation, which is recorded as a reduction to common stock. The cost is amortized to compensation expense over the vesting period. Stock award activity for the years ended December 31 was:

	2004	2003	2002
Restricted common shares awarded	**209,650**	102,060	113,410
Weighted average market price of shares awarded	**$ 39.95**	$ 41.39	$ 42.92
Compensation cost charged against income (in thousands)	**$ 5,616**	$ 6,366	$ 4,101

Performance Share Awards

Performance shares awarded under the plan are for a specified number of shares of common stock that entitles the holder to receive a cash payment, shares of common stock or a combination thereof. The final value of the award is determined by the achievement of certain performance objectives. The awards vest at the end of a specified period, usually three years. We account for performance share awards by accruing compensation expense over the vesting period based on: (i) the number of shares expected to be paid which is based on the probable achievement of performance objectives; and (ii) the fair value of the shares. For 2004, 2003 and 2002, we recorded compensation expense totaling $6.1 million, $5.5 million and $3.6 million, respectively.

During the vesting period, the recipient of a performance share award has no shareholder rights. However, recipients will be paid an amount equal to the dividend equivalent on such shares. Performance share awards are nontransferable and are subject to risk of forfeiture. As of December 31, 2004, there were 619,044 performance share awards outstanding.

NOTE-16 SEGMENT AND RELATED INFORMATION

We operate our businesses through three strategic business units (Energy Resources, Energy Distribution and Energy Gas). Each business unit has utility and non-utility operations. The balance of our business consists of Corporate & Other. Based on this structure, we set strategic goals, allocate resources and evaluate performance. This results in the following reportable segments.

Energy Resources

- *Utility – Power Generation* operations include the power generation services of Detroit Edison, the company's electric utility. Electricity is generated from Detroit Edison's numerous fossil plants or its nuclear plant and sold throughout Southeastern Michigan to residential, commercial, industrial and wholesale customers.
- *Non-utility*
  - *Energy Services* is comprised of various businesses that develop, acquire and manage energy-related assets and services. Such projects include coke production, synfuels production, on-site energy projects and merchant generation facilities.
  - *Energy Marketing & Trading* consists of the electric and gas marketing and trading operations of DTE Energy Trading Company and the natural gas marketing and trading operations of DTE Enterprises. Energy Marketing & Trading enters into forwards, futures, swaps and option contracts as part of its trading strategy.
  - *Other Non-utility* operations consist primarily of businesses involved in coal services and landfill gas recovery. Also includes administrative and general expenses not allocated to other non-utility businesses.

Energy Distribution

- *Utility – Power Distribution* operations include the electric distribution services of Detroit Edison. Energy Distribution distributes electricity generated by Energy Resources and alternative energy suppliers to Detroit Edison's 2.1 million residential, commercial and industrial customers.
- *Non-utility* operations include businesses that assemble, market, distribute and service a broad portfolio of distributed generation products, provides application engineering, and monitors and manages system operations.

Energy Gas

- *Utility* operations include gas distribution services provided by MichCon, the company's gas utility that purchases, stores and distributes natural gas throughout Michigan to 1.2 million residential, commercial and industrial customers.
- *Non-utility* operations include the production of gas and the gathering, processing and storing of gas. Certain pipeline and storage assets are supported by the Energy Marketing & Trading segment.

Corporate & Other includes administrative and general expenses, and interest costs of DTE Energy corporate that have not been allocated to the utility and non-utility businesses. Corporate & Other also includes various other non-utility operations, including investments in new emerging energy technologies.

The income tax provisions or benefits of DTE Energy's subsidiaries are determined on an individual company basis and recognize the tax benefit of Section 29 tax credits and net operating losses. The subsidiaries record income tax payable to or receivable from DTE Energy resulting from the inclusion of its taxable income or loss in DTE Energy's consolidated tax return. Inter-segment revenues primarily consist of power sales, gas sales and coal transportation services between Energy Resources Utility-Power Generation, Energy Services, Energy Marketing & Trading and Non-utility Other, and Energy Gas-Non-utility. DTE Energy's interest income totaled $55 million in 2004, $37 million in 2003 and $29 million in 2002, and is primarily associated with the Energy Services and Corporate & Other segments. Financial data of the business segments follows:

2004 *(in Millions)*	Operating Revenue	Depreciation, Depletion & Amortization	Interest Expense	Income Taxes	Net Income	Total Assets	Goodwill	Capital Expenditures
Energy Resources								
Utility – Power Generation	$ 2,210	$ 272	$ 167	$ 23	$ 62	$ 8,288	$ 406	$ 332
Non-utility								
Energy Services	1,089	82	33	64	188	1,790	41	17
Energy Marketing & Trading	665	3	5	46	92	1,098	17	8
Other	576	8	3	(11)	1	126	4	13
Total Non-utility	2,330	93	41	99	281	3,014	62	38
Total Energy Resources	4,540	365	208	122	343	11,302	468	370
Energy Distribution								
Utility – Power Distribution	1,358	251	113	41	88	4,554	796	370
Non-utility	46	2	2	(10)	(19)	64	16	1
	1,404	253	115	31	69	4,618	812	371
Energy Gas								
Utility – Gas Distribution	1,682	103	58	(9)	20	3,128	772	113
Non-utility	119	20	11	11	21	549	15	48
	1,801	123	69	2	41	3,677	787	161
Corporate & Other	16	3	198	10	(10)	2,275	–	2
Reconciliation & Eliminations	(647)	–	(72)	–	–	(584)	–	–
Total from Continuing Operations	$ 7,114	$ 744	$ 518	$165	443	21,288	2,067	904
Discontinued Operations (Note 3)					(12)	9	–	–
Total					$ 431	$21,297	$2,067	$ 904
Electric Utility	$ 3,568	$ 523	$ 280	$ 64	$ 150	$12,842	$1,202	$ 702
Gas Utility	1,682	103	58	(9)	20	3,128	772	113
Non-utility	2,495	115	54	100	283	3,627	93	87
Corporate & Other	16	3	198	10	(10)	2,275	–	2
Reconciliation & Eliminations	(647)	–	(72)	–	–	(584)	–	–
Total from Continuing Operations	$ 7,114	$ 744	$ 518	$165	443	21,288	2,067	904
Discontinued Operations (Note 3)					(12)	9	–	–
Total					$ 431	$21,297	$2,067	$ 904

2003 [illegible]	Operating Revenue	Depreciation, Depletion & Amortization	Interest Expense	Income Taxes	Net Income	Total Assets	Goodwill	Capital Expenditures
Energy Resources								
Utility – Power Generation	$ 2,448	$ 224	$ 157	$135	$ 235	$ 7,216	$ 406	$ 340
Non-utility								
Energy Services	929	84	20	(249)	199	1,644	41	22
Energy Marketing & Trading	764	2	2	20	45	1,067	17	6
Other	297	7	2	(17)	(2)	128	4	11
Total Non-utility	1,990	93	24	(246)	242	2,839	62	39
Total Energy Resources	4,438	317	181	(111)	477	10,055	468	379
Energy Distribution								
Utility – Power Distribution	1,247	249	127	10	17	5,333	796	240
Non-utility	39	2	–	(8)	(15)	65	12	1
	1,286	251	127	2	2	5,398	808	241
Energy Gas								
Utility – Gas Distribution	1,498	101	58	–	29	3,021	776	99
Non-utility	90	18	8	14	29	518	15	28
	1,588	119	66	14	58	3,539	791	127
Corporate & Other	12	–	219	(28)	(57)	2,383	–	4
Reconciliation & Eliminations	(283)	–	(47)	–	–	(636)	–	–
Total from Continuing Operations	$ 7,041	$ 687	$ 546	$(123)	480	20,739	2,067	751
Discontinued Operations (Note 3)					68	14	–	–
Cumulative Effect of Accounting Changes					(27)	–	–	–
Total					$ 521	$20,753	$2,067	$ 751

Electric Utility	$ 3,695	$ 473	$ 284	$145	$ 252	$12,549	$1,202	$ 580
Gas Utility	1,498	101	58	–	29	3,021	776	99
Non-utility	2,119	113	32	(240)	256	3,422	89	68
Corporate & Other	12	–	219	(28)	(57)	2,383	–	4
Reconciliation & Eliminations	(283)	–	(47)	–	–	(636)	–	–
Total from Continuing Operations	$ 7,041	$ 687	$ 546	$(123)	480	20,739	2,067	751
Discontinued Operations (Note 3)					68	14	–	–
Cumulative Effect of Accounting Changes					(27)	–	–	–
Total					$ 521	$20,753	$2,067	$ 751

2002 *(in Millions)*	Operating Revenue	Depreciation, Depletion & Amortization	Interest Expense	Income Taxes	Net Income	Total Assets	Goodwill	Capital Expenditures
Energy Resources								
Utility – Power Generation	$ 2,711	$ 331	$ 184	$120	$ 241	$ 7,334	$ 406	$ 395
Non-utility								
Energy Services	645	81	19	(268)	182	1,536	41	130
Energy Marketing & Trading	681	3	15	13	25	822	17	–
Other	102	9	4	(19)	7	256	4	8
Total Non-utility	1,428	93	38	(274)	214	2,614	62	138
Total Energy Resources	4,139	424	222	(154)	455	9,948	468	533
Energy Distribution								
Utility – Power Distribution	1,343	246	127	58	111	4,154	796	290
Non-utility	39	2	1	(9)	(16)	60	12	2
	1,382	248	128	49	95	4,214	808	292
Energy Gas								
Utility – Gas Distribution	1,369	104	57	36	66	2,857	776	93
Non-utility	87	19	6	14	26	504	16	32
	1,456	123	63	50	92	3,361	792	125
Corporate & Other	16	–	232	(32)	(56)	2,378	–	24
Reconciliation & Eliminations	(264)	(58)	(76)	3	–	(548)	–	–
Total from Continuing Operations	$ 6,729	$ 737	$ 569	$ (84)	586	19,353	2,068	974
Discontinued Operations (Note 3)					46	632	44	10
Total					$ 632	$19,985	$2,112	$ 984

Electric Utility	$ 4,054	$ 577	$ 311	$178	$ 352	$11,488	$1,202	$ 685
Gas Utility	1,369	104	57	36	66	2,857	776	93
Non-utility	1,554	114	45	(269)	224	3,178	90	172
Corporate & Other	16	–	232	(32)	(56)	2,378	–	24
Reconciliation & Eliminations	(264)	(58)	(76)	3	–	(548)	–	–
Total from Continuing Operations	$ 6,729	$ 737	$ 569	$ (84)	586	19,353	2,068	974
Discontinued Operations (Note 3)					46	632	44	10
Total					$ 632	$19,985	$2,112	$ 984

NOTE-17 SUPPLEMENTARY QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Quarterly earnings per share may not total for the years, since quarterly computations are based on weighted average common shares outstanding during each quarter. We account for the operations of ITC and SMGC as discontinued operations (Note 3).

(in Millions, except per share amounts)

2004	First Quarter (1)	Second Quarter	Third Quarter	Fourth Quarter	Year
Operating Revenues	**$ 2,093**	**$ 1,501**	**$ 1,594**	**$ 1,926**	**$ 7,114**
Operating Income	**$ 368**	**$ 95**	**$ 173**	**$ 210**	**$ 846**
Net Income (Loss)					
From continuing operations	**$ 197**	**$ 35**	**$ 93**	**$ 118**	**$ 443**
Discontinued operations	**(7)**	**–**	**–**	**(5)**	**(12)**
Total	**$ 190**	**$ 35**	**$ 93**	**$ 113**	**$ 431**
Basic Earnings (Loss) per Share					
From continuing operations	**$ 1.16**	**$ .20**	**$ .54**	**$ .68**	**$ 2.56**
Discontinued operations	**(0.04)**	**–**	**–**	**(.03)**	**(.06)**
Total	**$ 1.12**	**$ .20**	**$ .54**	**$ .65**	**$ 2.50**
Diluted Earnings (Loss) per Share					
From continuing operations	**$ 1.15**	**$ .20**	**$ .54**	**$ .68**	**$ 2.55**
Discontinued operations	**(0.04)**	**–**	**–**	**(.03)**	**(.06)**
Total	**$ 1.11**	**$ .20**	**$ .54**	**$ .65**	**$ 2.49**

2003					
Operating Revenues	$ 2,095	$ 1,600	$ 1,654	$ 1,692	$ 7,041
Operating Income	$ 217	$ 71	$ 232	$ 227	$ 747
Net Income (Loss)					
From continuing operations	$ 108	$ (37)	$ 180	$ 229	$ 480
Discontinued operations	74	(2)	(4)	–	68
Cumulative effect of accounting changes	(27)	–	–	–	(27)
Total	$ 155	$ (39)	$ 176	$ 229	$ 521
Basic Earnings (Loss) per Share					
From continuing operations	$ .65	$ (.22)	$ 1.07	$ 1.36	$ 2.87
Discontinued operations	.44	(.01)	(.02)	–	.41
Cumulative effect of accounting changes	(.17)	–	–	–	(.17)
Total	$ .92	$ (.23)	$ 1.05	$ 1.36	$ 3.11
Diluted Earnings (Loss) per Share					
From continuing operations	$ .64	$ (.22)	$ 1.06	$ 1.36	$ 2.85
Discontinued operations	.44	(.01)	(.02)	–	.40
Cumulative effect of accounting changes	(.16)	–	–	–	(.16)
Total	$ .92	$ (.23)	$ 1.04	$ 1.36	$ 3.09

(1) Previously reported first quarter 2004 amounts have been adjusted to reflect the retroactive adoption of FSP No. 106-2, relating to the impact of the *Medicare Act on postretirement benefit costs (Note 2).*

statistical review

(Dollars in Millions, Except Common Share Data)	2004	2003	2002	2001
Operating Revenues				
Utility	$ **5,250**	$ 5,193	$ 5,423	$ 4,659
Non-utility (1)	**1,864**	1,848	1,306	1,128
Total	$ **7,114**	$ 7,041	$ 6,729	$ 5,787
Net Income				
Utility	$ **170**	$ 281	$ 418	$ 198
Non-utility (1)	**273**	199	168	111
	443	480	586	309
Discontinued Operations	**(12)**	68	46	20
Cumulative Effect of Accounting Changes	**–**	(27)	–	3
	$ **431**	$ 521	$ 632	$ 332
Diluted Earnings per Share				
Utility	$ **.98**	$ 1.67	$ 2.53	$ 1.29
Non-utility (1)	**1.57**	1.18	1.02	0.72
	2.55	2.85	3.55	2.01
Discontinued Operations	**(0.06)**	.40	.28	.13
Cumulative Effect of Accounting Changes	**–**	(.16)	–	.02
	$ **2.49**	$ 3.09	$ 3.83	$ 2.16
Electric Utility Deliveries *(Millions of kWh)*	**52,416**	53,194	54,105	51,516
Electric Utility Customers at Year End *(Thousands)*	**2,147**	2,132	2,136	2,125
Gas Utility Deliveries *(Bcf)* (2)	**854**	909	837	917
Gas Utility Customers at Year End *(Thousands)* (2)	**1,258**	1,249	1,267	1,235
Financial Position at Year End				
Net property (3)	$ **10,491**	$ 10,324	$ 10,542	$ 10,255
Total assets (3)	$ **21,297**	$ 20,753	$ 19,985	$ 19,587
Long-term debt, including capital leases	$ **7,606**	$ 7,669	$ 7,803	$ 7,928
Total shareholders' equity	$ **5,548**	$ 5,287	$ 4,565	$ 4,589
Common Share Data				
Dividends declared per share	$ **2.06**	$ 2.06	$ 2.06	$ 2.06
Average shares outstanding-diluted *(millions)*	**173**	168	165	154
Book value per share	$ **31.85**	$ 31.36	$ 27.26	$ 28.48
Market price: High	$ **45.49**	$ 49.50	$ 47.70	$ 47.13
Low	$ **37.88**	$ 34.00	$ 33.05	$ 33.13
Year end	$ **43.13**	$ 39.40	$ 46.40	$ 41.94
Miscellaneous Financial Data				
Cash flow from operations	$ **995**	$ 950	$ 996	$ 811
Capital expenditures	$ **904**	$ 751	$ 984	$ 1,096
Employees at year end	**11,207**	11,099	11,095	11,030

(1) Includes Corporate & Other and/or eliminations.
(2) Gas Utility data shown prior to May 2001 is presented for informational purposes only. The Gas Utility business was acquired on May 31, 2001.
(3) In conjunction with adopting SFAS No. 143, we reclassified previously accrued asset removal costs related to our regulated operations, which had been previously netted against accumulated depreciation, to an asset removal cost liability for the years 1999 through 2002. Amounts for years prior to 1999 are not available.

2000	1999	1998	1997	1996	1995	1994
$ 4,129	$ 4,047	$ 3,902	$ 3,657	$ 3,642	$ 3,634	$ 3,519
509	452	272	107	3	2	–
$ 4,638	$ 4,499	$ 4,174	$ 3,764	$ 3,645	$ 3,636	$ 3,519
$ 427	$ 434	$ 412	$ 405	$ 312	$ 406	$ 390
41	49	31	12	(3)	–	–
468	483	443	417	309	406	390
–	–	–	–	–	–	–
–	–	–	–	–	–	–
$ 468	$ 483	$ 443	$ 417	$ 309	$ 406	$ 390
$ 2.99	$ 3.00	$ 2.83	$ 2.79	$ 2.15	$ 2.80	$ 2.67
.28	.33	.22	.09	(.02)	–	–
3.27	3.33	3.05	2.88	2.13	2.80	2.67
–	–	–	–	–	–	–
–	–	–	–	–	–	–
$ 3.27	$ 3.33	$ 3.05	$ 2.88	$ 2.13	$ 2.80	$ 2.67
52,611	55,871	55,286	50,983	48,815	49,298	46,494
2,110	2,089	2,068	2,051	2,025	2,002	1,980
945	866	850	941	895	730	667
1,235	1,220	1,206	1,193	1,183	1,173	1,155
$ 8,081	$ 7,853	$ –	$ –	$ –	$ –	$ –
$ 13,350	$ 13,021	$ –	$ –	$ –	$ –	$ –
$ 4,039	$ 4,091	$ 4,323	$ 3,914	$ 3,894	$ 3,884	$ 3,951
$ 4,009	$ 3,909	$ 3,698	$ 3,706	$ 3,588	$ 3,763	$ 3,706
$ 2.06	$ 2.06	$ 2.06	$ 2.06	$ 2.06	$ 2.06	$ 2.06
143	145	145	145	145	145	146
$ 28.14	$ 26.75	$ 25.49	$ 24.51	$ 23.69	$ 23.62	$ 22.89
$ 41.25	$ 44.69	$ 49.25	$ 34.75	$ 37.25	$ 34.88	$ 30.25
$ 28.44	$ 31.06	$ 33.50	$ 26.13	$ 27.63	$ 25.75	$ 24.25
$ 38.94	$ 31.63	$ 43.06	$ 34.69	$ 32.38	$ 34.50	$ 26.13
$ 1,015	$ 1,084	$ 834	$ 905	$ 1,079	$ 913	$ 923
$ 749	$ 739	$ 589	$ 484	$ 531	$ 454	$ 366
9,144	8,886	8,781	8,732	8,526	8,340	8,494

words our industry uses

glossary

Coke and Coke Battery

Raw coal is heated to high temperatures in ovens to drive off impurities, leaving a carbon residue called coke. Coke is combined with iron ore to create a high metallic iron that is used to produce steel. A series of coke ovens configured in a module is referred to as a battery.

Customer Choice

The customer choice programs are statewide initiatives giving customers in Michigan the option to choose alternative suppliers for electricity and gas.

Gas Cost Recovery (GCR) Mechanism

A GCR mechanism authorized by the MPSC permitting MichCon to pass the cost of natural gas to its customers.

MPSC

The Michigan Public Service Commision regulates the state's energy, telecommunications and transportation services industries.

Power Supply Cost Recovery (PSCR) Mechanism

A PSCR mechanism authorized by the MPSC that allows Detroit Edison to recover through rates its fuel, fuel-related and purchased power expenses. The clause was suspended under Michigan's restructuring legislation (signed into law June 5, 2000), which lowered and froze electric customer rates. The clause was reinstated by the MPSC effective January 1, 2004.

Section 29 Tax Credits

Tax credits authorized under Section 29 of the Internal Revenue Code, designed to stimulate investment in and development of alternative fuel sources. The amount of a Section 29 tax credit can vary each year as determined by the Internal Revenue Service.

Securitization

Detroit Edison financed specific stranded costs at lower interest rates through the sale of rate reduction bonds by a wholly owned special purpose entity, the Detroit Edison Securitization Funding LLC.

Stranded Costs

Costs incurred by utilities in order to serve customers in a regulated environment that absent special regulatory approval would not otherwise expect to be recoverable if customers switch to alternative suppliers of electricity and gas.

Synfuel

The fuel produced through a process involving chemically modifying and binding particles of coal. Synfuels are used for power generation and coke production. Synfuel production generates Section 29 tax credits.

overview

DTE Energy's common stock is listed on the New York Stock Exchange and the Chicago Stock Exchange (symbol DTE). The following table indicates the reported high and low sale prices on the New York Stock Exchange Composite Tape for DTE Energy common stock, and dividends paid per share for each quarterly period during the past two years:

Calendar	Quarter	High	Low	Dividends Paid Per Share
2004	First	$ 42.29	$ 37.92	$ 0.515
	Second	41.58	37.88	0.515
	Third	42.21	39.31	0.515
	Fourth	45.49	41.44	0.515
2003	First	$ 49.50	$ 38.51	$ 0.515
	Second	44.95	38.52	0.515
	Third	38.98	34.00	0.515
	Fourth	39.76	35.12	0.515

As of Dec. 31, 2004, 174,209,034 shares of the company's common stock were outstanding. These shares were held by a total of 99,832 shareholders of record.

distribution of ownership of DTE Energy common stock as of Dec. 31, 2004:

Type of Owner	Owners	Shares
Individuals	40,889	12,636,138
Joint Accounts	37,363	15,386,259
Trust Accounts	1,468	1,047,942
Nominees	38	136,597,601
Institutions/Foundations	40	40,651
Brokers/Security Dealers	46	30,529
Others	19,988	8,469,914
Total	**99,832**	**174,209,034**

State and Country	Owners	Shares
Michigan	51,494	20,538,997
Florida	5,941	2,653,067
California	4,903	1,703,692
New York	3,908	137,904,170
Illinois	3,765	1,380,697
Ohio	3,111	1,029,857
44 other states	26,300	8,865,125
Foreign countries	410	133,429
Total	**99,832**	**174,209,034**

annual meeting of shareholders

The 2005 Annual Meeting of DTE Energy Shareholders will be held Thursday, April 28, 2005, at 10 a.m. (EST) in the DTE Energy Building, 660 Plaza Drive, Detroit, MI.

corporate address

DTE Energy, 2000 Second Ave.
Detroit, MI 48226-1279
Telephone: **313.235.4000** dteenergy.com

independent registered public accounting firm

Deloitte & Touche LLP
600 Renaissance Center, Suite 900
Detroit, MI 48243-1704

form 10-K

We will provide, without charge to shareholders, copies of our Form 10-K filed with the Securities and Exchange Commission. Written requests should be directed to:

Susan M. Beale
Vice President and Corporate Secretary
DTE Energy, 2000 Second Ave.
Detroit, MI 48226-1279
or dteenergy.com/investors

officer certifications

In 2004, our chief executive officer (CEO) submitted to the New York Stock Exchange (NYSE) the annual CEO certification regarding DTE Energy's compliance with the NYSE's corporate governance listing standards, stating that he was not aware of any violation to the NYSE corporate governance listing standards. Our CEO made his annual certification to the NYSE as of May 27, 2004. In addition, we have filed as exhibits to the Annual Report on Form 10-K with the Securities and Exchange Commission, the certifications required under Section 302 of the Sarbanes-Oxley Act of 2002 regarding the quality of the company's public disclosures in the fiscal year-end 2004 reports.

other information about DTE Energy

transfer agent

The Bank of New York
Send certificates for transfer and address changes to:
Receive and Deliver Department, P.O. Box 11002
Church Street Station, New York, NY 10286
Telephone: **866.388.8558** www.stockbny.com

registrar of stock and other information

Address shareholder inquiries to:
The Bank of New York, Shareholder Relations Department
P.O. Box 11258, Church Street Station, New York, NY 10286
or e-mail inquires to: shareowners@bankofny.com

As a service to shareholders of record, DTE Energy offers direct deposit of dividend payments through The Bank of New York. Payments can be electronically transferred directly to the bank or savings and loan account of choice on the payment date. Write to the address above, or call **866.388.8558** to request a Direct Deposit Authorization Form.

Shareholders of record can elect to receive future copies of our Annual Report and Proxy Statement electronically by marking the appropriate box on their proxy card as instructed. By electing electronic delivery, you are stating that you currently have or expect to have access to the Internet.

DTE LISTED NYSE

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