

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

### Overview

DTE Energy is a growing and diversified energy company with 2005 revenues in excess of \$9 billion and approximately \$23 billion in assets. Since 2003, our asset base has increased by 12% and operating revenues have grown by 29%.

We are the parent company of The Detroit Edison Company (Detroit Edison) and Michigan Consolidated Gas Company (MichCon), regulated electric and gas utilities engaged primarily in the business of providing electricity and natural gas sales and distribution services throughout southeastern Michigan. We operate three energy-related non-utility segments with operations throughout the United States.

In 2005, our utilities and Power and Industrial Projects segment generated most of our earnings. The improvement in earnings was due to rate increases at our Michigan utilities, favorable weather and continued asset gains from the synthetic fuel business. Earnings were also impacted by mark-to-market losses in our Fuel Transportation and Marketing segment and losses from discontinued operations.

Our 2005 financial performance improved over 2004. The following table summarizes our income since 2003:

<i>(in millions, except Earnings per Share)</i>	2005	2004	2003
Net Income	\$ 537	\$ 431	\$ 521
Earnings per Diluted Share	\$ 3.05	\$ 2.49	\$ 3.09
<b>Excluding Discontinued Operations and Accounting Changes</b>			
Income from Continuing Operations	\$ 576	\$ 461	\$ 494
Earnings per Diluted share	\$ 3.27	\$ 2.66	\$ 2.93

The items discussed below influenced our 2005 financial performance and may affect future results:

- Effects of weather and accounts receivable on utility operations;
- Electric rate orders, electric Customer Choice program, and coal and uranium supply;
- Gas rate and gas cost recovery orders and gas supply;
- Synfuel-related earnings and the impact of higher oil prices on production credit phase-outs;
- Investments in our unconventional gas production business;
- Mark-to-market losses in our Fuel Transportation and Marketing business; and
- Cost reduction efforts and required capital investment.

### Utility Operations

*Weather* - Earnings at our utility operations are seasonal and very sensitive to weather. Electric utility earnings are dependent on hot summer weather, while the gas utility's results are dependent on cold winter weather. The following table explains the impact of weather relative to 30-year historical normal weather temperatures for each utility.

*(Dollars in Millions)*

Year	Percentage Change from Normal (1)		Estimated Effect on Net Income		
	Electric Utility	Gas Utility	Electric Utility	Gas Utility	Total
2005	47 %	(3) %	\$ 63	\$ (4)	\$ 59
2004	(17) %	(4) %	\$ (40)	\$ (9)	\$ (49)
2003	(13) %	2 %	\$ (24)	\$ 3	\$ (21)

(1) Electric Utility is based on cooling degree days and the Gas Utility is based on heating degree days.

The positive impact of warmer weather was partially mitigated by the rate cap on residential customers which prevented us from passing through increased generation and purchased power costs incurred to serve the higher demand. Additionally, we occasionally experience various types of storms that damage our electric distribution infrastructure resulting in power outages. Restoration and other costs associated with storm-related power outages lowered pretax earnings by \$82 million in 2005, \$48 million in 2004 and \$72 million in 2003.

*Receivables* - Both utilities continue to experience high levels of past due receivables, especially within our Gas Utility operations. The increase is attributable to economic conditions, high natural gas prices and the lack of adequate levels of assistance for low-income customers.

We have taken aggressive actions to reduce the level of past due receivables including, increased 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 2005, we sold previously written-off accounts of \$187 million resulting in a gain and net proceeds of \$6 million. The gain was recorded as a recovery through bad debt expense, which is included within operation and maintenance expense. As a result of these factors, our allowance for doubtful accounts expense for the two utilities decreased to \$98 million in 2005 from \$105 million in 2004.

The April 2005 Michigan Public Service Commission (MPSC) gas rate order provided for an uncollectible tracking mechanism for MichCon. We will file an annual application comparing our actual uncollectible expense to our designated revenue recovery of approximately \$37 million. Ninety percent of the difference from the date of the order will be refunded or surcharged after an annual reconciliation proceeding before the MPSC.

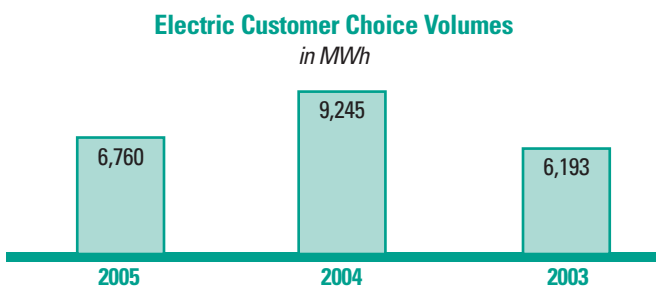
### Electric Utility

*Electric Rate Orders* - In 2004, the MPSC issued interim and final rate orders that authorized electric rate increases totaling \$374 million, 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 MPSC also authorized the recovery of approximately \$385 million in regulatory assets, including stranded costs. As a result of increased rates, our 2005 pretax margins were higher by \$116 million.

*Electric Customer Choice* - Our customers have the option of participating in the electric Customer Choice program where they can select an alternative electric supplier. Due to distorted pricing mechanisms during the initial period of electric Customer Choice, many commercial customers chose alternative electric suppliers. The impact of the final rate order in 2004, that increased base rates including the recovery of lost margins and transition charges, combined with recent higher wholesale electric prices has resulted in many former electric Customer Choice customers migrating back to Detroit Edison for electrical generation service, partially mitigating the financial impact of the electric Customer Choice program.

The return of customers from the electric Customer Choice program resulted in higher gross margins during 2005. The following graph depicts the electric Customer Choice volumes:



We continue to work with the MPSC to address issues associated with the electric Customer Choice program. In February 2005, we filed a revenue-neutral rate restructuring proposal with the MPSC designed to adjust rates for each customer class to be reflective of the full costs incurred to service such customers. In December 2005, the MPSC issued an order that took some initial steps to improve the current competitive imbalance in Michigan's electric Customer Choice program. The December 2005 order establishes cost-based power supply rates for Detroit Edison's full service customers. Electric Customer Choice participants will pay cost-based distribution rates, while Detroit Edison's full service commercial and industrial customers will pay cost-based distribution rates that reflect the cost of the residential rate subsidy. Residential customers pay a subsidized below cost rate for distribution service. These revenue neutral revised rates were effective February 1, 2006.

*Coal Supply* - Our generating fleet produces in excess of 70% of its electricity from coal. Increasing coal demand from domestic and international markets has resulted in significant price increases. In addition, difficulty in recruiting workers, obtaining environmental permits and finding economically recoverable amounts of new coal has resulted in decreasing coal output from the central Appalachian region. Furthermore, as a result of environmental regulation and declining eastern coal stocks, demand for cleaner burning western coal has increased. This increased demand for western coal has also resulted in a corresponding demand for western rail shipping, straining railroad capacity, resulting in longer lead times for western coal shipments.

*Uranium Supply* - We operate one nuclear facility that undergoes a periodic refueling outage approximately every eighteen months. Uranium prices have been rising due to supply concerns. In the future, there may be additional nuclear facilities constructed in the industry that may place additional pressure on uranium supplies and prices.

### Gas Utility

*Gas Final Rate Order* - In April 2005, the MPSC issued a final rate order authorizing MichCon to earn a rate of return on common equity of 11% based on a 50% debt and 50% equity capital structure. Highlights of the order include:

- \$61 million increase in annual base rates;
- base rate increase includes \$25 million to recover safety and training costs;
- deferral as a regulatory liability for the non-capitalized portion of negative pension expense; and
- adoption of a tracking mechanism for uncollectible accounts receivable.

The final rate order from the MPSC denied recovery or required accounting impairment for the following items:

- \$25 million of allocated merger interest from DTE Energy related to the acquisition of MCN Energy;
- \$6 million of internal labor and legal costs to remediate manufactured gas plant (MGP) sites;
- \$5 million as a result of a change to the allocation of historical MGP insurance proceeds;
- \$6 million of computer equipment and related depreciation; and
- \$42 million impairment related to 90% of the cost of a computer billing system in place prior to DTE Energy's acquisition of MCN Energy. This impairment had a minimal earnings impact on DTE Energy because a valuation allowance was established for this asset at the time of the MCN acquisition in 2001.

Additionally, the rate order adjusted MichCon's depreciation rates and the related revenue requirements with no resulting impact on net income.

*Gas Cost Recovery (GCR) order* - Based on rate orders in place for 2001 and 2002, we filed a gas cost recovery case in 2002 and recorded a \$26 million regulatory asset related to unbilled volumes as of December 31, 2001. Over time we recorded \$3 million of interest associated with this regulatory asset. In its April 28, 2005 order, the MPSC disallowed recovery and we recorded the impact of the disallowance in the first quarter of 2005.

*Natural Gas Supply* - Increased demand from natural gas power plants, 2005 hurricane related supply disruptions, regulatory constraints and limited exploration have combined to strain existing natural gas supplies and caused substantial increases in prices.

### Non-utility Operations

We anticipate significant investment opportunities within our non-utility businesses. We employ disciplined investment criteria

when assessing opportunities that will leverage our existing assets, skill and expertise. Specifically, we invest in targeted energy markets with attractive competitive dynamics where meaningful scale is in alignment with our risk profile. Assuming no phase-out of production tax credits, the source of investment capital is the estimated cumulative \$1.2 billion we anticipate from synfuel cash flow which consists of cash from operations, asset sales, and the utilization of current and previously earned production tax credits to reduce tax payments. Tax credit carryforward utilization in part could be extended past 2008, if taxable income is reduced from current forecasts. However, if oil prices remain at current levels or continue to increase, the estimated cash flow from the synfuel business would be significantly less and would adversely impact the success of this strategy, unless we identify alternative sources of cash.

### Power and Industrial Projects

We anticipate building around our core strengths in the markets where we operate. In determining the markets in which to compete, we closely examine the regulatory environment, the number of competitors and our ability to achieve sustainable margins. We plan to maximize the effectiveness of our inter-related businesses as we expand from our current regional focus. As we pursue growth opportunities, our first priority will be to achieve value-added returns.

We plan to focus on the following areas for growth:

- Optimizing the remaining life of our synfuel portfolio;
- Providing operating services to owners of industrial and power plants;
- Acquiring and developing solid fuel-fired power plants;
- Expanding on-site energy projects; and
- Developing new tax advantaged opportunities.

*Synfuel-related Earnings* - We operate nine synthetic fuel production plants throughout the United States. Synfuel plants chemically change coal into a synthetic fuel as determined under the Internal Revenue Code. Production tax credits are provided for the production and sale of solid synthetic fuel produced from coal. These tax credits expire on December 31, 2007. Our synthetic fuel plants generate operating losses which are offset by the resulting production tax credits. We have not had sufficient taxable income to fully utilize production tax credits earned in prior periods. As of December 31, 2005, we have \$484 million in tax credit carry-forwards.

To optimize income and cash flow from our synfuel operations, we have sold interests in all nine of our facilities, representing 91% of our total production capacity as of December 31, 2005. We will continue to evaluate opportunities to sell additional interests in our two remaining majority-owned plants. Proceeds from the sales are contingent upon production levels and the value of such credits. When we sell an interest in a synfuel project, we recognize the gain as the facility produces and sells synfuel and when there is persuasive evidence that the sales proceeds have become fixed or determinable and collectibility is reasonably assured. 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 production tax credit can vary each year and is adjusted annually by an inflation factor as published by the Internal Revenue Service (IRS) in April of the following year. The value of the production 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. During 2005, the monthly average wellhead prices were approximately \$6 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 2004 through 2007 are as follows:

	Reference Price	Beginning Phase-Out Price	Ending Phase-Out Price
2004 (actual)	\$36.75	\$51.35	\$64.46
2005 (estimated)	\$51	\$53	\$66
2006 (estimated)	Not Available	\$53	\$67
2007 (estimated)	Not Available	\$54	\$68

Recent events have increased domestic crude oil prices, including hurricane-related supply disruptions and continued worldwide demand. Through December 31, 2005, the NYMEX daily closing price of a barrel of oil for 2005 averaged approximately \$57, which due to the uncertainty of the wellhead/NYMEX difference, is comparable to an approximate \$51 Reference Price. For the remaining life of the tax credits, if the Reference Price falls within or exceeds the phase-out range, the availability of production tax credits in that year would be reduced or eliminated. Any actual tax credit phase-out for 2006 and available tax credits, if any, will not be certain until published by the IRS in April 2007. As of February 28, 2006, the realized and unrealized NYMEX daily closing price of a barrel of oil was \$65.08, equating to an estimated Reference Price of \$59, which is within the phase-out range. If prices remain at this level throughout 2006, we would experience a phase-out of the production tax credits and our synthetic fuel business would be adversely affected; this could have an impact on our synthetic fuel production plans which, in turn, may have a material adverse impact on our results of operations, cash flow, and financial condition. However, we cannot predict with any certainty the Reference Price for 2006 or beyond.

There is legislation pending in Congress that may impact the potential phase-out of production tax credits for 2006 and 2007. The legislation would use the prior year oil price to determine the current year Reference Price. We are unable to predict the outcome of this legislation.

The gain from the sale of synfuel facilities is comprised of fixed and variable components. The fixed component represents note payments of principal and interest, is not subject to refund, and is recognized as a gain when earned and collectibility is assured. The variable component is based on an estimate of tax credits allocated to our partners, is subject to refund based on the annual oil price phase-out, and is recognized as a gain only when the probability of refund is considered remote and collectibility is assured. Additionally, based on estimates of tax credits allocated, our partners reimburse us (through the project entity) for the operating losses of the synfuel

facilities. In the event that the tax credit is phased out, we are contractually obligated to refund to our partners all or a portion of the operating losses funded by our partners. To assess the probability of refund, we use valuation and analysis models that calculate the probability of surpassing the estimated lower band of the phase-out range for the Reference Price of oil for the year. Due to the rise in oil prices, there was a possibility that the 2005 Reference Price of oil could have reached the threshold at which production tax credits would have begun to phase-out. We deferred all variable gains for the first three quarters of 2005. However, in the fourth quarter of 2005, when there was persuasive evidence that the Reference Price of oil would not surpass the estimated lower band of the phase-out range, we recognized all the variable gains related to 2005, of which \$167 million (pre-tax) were attributable to the first three quarters of 2005.

Due to changes in the agreements with certain of our synfuel partners and the exercise of existing rights by other of our synfuels partners, a higher percentage of the expected payments in 2006 may be variable note payments. As a result, a larger portion of the 2006 synfuel payments may be subject to refund should a phase-out occur. We will likely defer recognition of the quarterly variable and certain indemnified fixed note payments in 2006 until the probability of refund is remote and collectibility is assured.

As discussed in Note 12, we have entered into derivative and other contracts to economically hedge a portion of our 2006 and 2007 synfuel cash flow exposure related to the risk of oil prices increasing. The derivative contracts are marked to market with changes in fair value recorded as an adjustment to synfuel gains. We recorded a pretax mark to market gain of \$48 million during 2005. As part of our synfuel-related risk management strategy, we continue to evaluate alternatives available to mitigate unhedged exposure to oil price volatility. These contracts, and other actions we can take and have taken, will protect approximately 53% of our 2006 cash flow and 31% of our 2007 cash flow. As our risk management position changes due to market volatility or legislative actions, we may adjust our hedging strategy in response to changing conditions.

In addition to entering into economic hedges, we can mitigate our exposure to a tax credit phase-out by shutting down or reducing production at our synfuel facilities, which decreases the amount of operating losses we generate. We regularly monitor oil prices and have created contingency plans to cease synfuel production.

Assuming no synfuel tax credit phase-out, we expect cash flow from our synfuel business will be approximately \$1.2 billion from 2006 to 2008. If prices remain at current levels or increase throughout 2006, synfuel production levels may be reduced, which would reduce the income and cash flow from this business. If the Reference Price results in a complete phase out of the synfuel tax credits for 2006, and assuming the previously discussed current level of economic hedges and an early cessation of synfuel production to avoid operating losses, there is a potential negative impact to net income and cash flow of \$160 million and \$140 million, respectively, before any potential asset impairment and goodwill write-off.

## Unconventional Gas Production

During the past year, natural gas prices have reached historically high levels. These high prices provide attractive opportunities for our Unconventional Gas Production business segment. We are an experienced operator with 15 years of experience in the Antrim shale in northern Michigan, and we recently expanded our operations in the Barnett shale basin in north central Texas. Recent leasehold acquisitions have increased our total leasehold acreage to 452,621 acres (366,693 net of interest of others). Over the next few years, our goal is to expand our existing leasehold acreage position and transform unproved acreage into proved reserves.

*Antrim Shale* - We plan to grow through the extension of existing producing areas and acquisition of other producer's properties. Additionally, we intend to develop existing acreage using the latest horizontal drilling techniques and to continue to search for expansion acreage. Some of our long-term fixed-price obligations for production of Antrim gas begin to expire in 2006. This will create opportunities to remarket Antrim production at significantly higher current market rates.

	2005	2004	2003
<b>Michigan - Antrim Shale</b>			
Net Producing Wells	1,630	1,523	1,471
Production Volume (Bcfe)	21.5	22.5	23.2
Proved Reserves (Bcfe)	338.4	335.4	351.9
Net Developed Acreage	217,643	213,959	212,067
Net Undeveloped Acreage	73,056	79,025	81,133
Capital Expenditures (in millions)	\$ 37	\$ 22	\$ 26
Future Net Cash Flows (in millions) (1)	\$ 1,307	\$ 760	\$ 485
Average gas price with hedges (per Mcf)	\$ 3.10	\$ 3.10	\$ 2.97
Average gas price without hedges (per Mcf) (2)	\$ 7.73	\$ 5.57	\$ 4.98

(1) Represents the standardized measure of discounted future net cash flows as calculated by an independent engineering firm utilizing extensive estimates. The estimated future net cash flow computations should not be considered to represent our estimate of the expected revenues or the current value of existing proved reserves and do not include the impact of hedge contracts.

(2) The gas produced in the Antrim shale is subject to hedges that begin to expire in 2006. In 2006, we expect to remarket 2.0 Bcf at current market pricing. For 2007, we anticipate remarketing an additional 1.8 Bcf.

*Barnett Shale* - We anticipate significant opportunities in our existing Barnett shale acreage and expect continued extension of producing areas within the Fort Worth Basin. We are currently in the test and development phase for unproved and recently acquired Barnett shale acreage. We plan to increase our acreage through small negotiated acquisitions to build scale.

	2005	2004	2003
<b>Texas - Barnett Shale</b>			
Net Producing Wells	55	1	-
Production Volume (Bcfe)	0.7	-	-
Proved Reserves (Bcfe)	58.6	7.9	-
Net Developed Acreage	14,637	316	-
Net Undeveloped Acreage	61,627	48,541	3,156
Capital Expenditures (in millions)	\$ 107	\$ 16	\$ 2
Future Net Cash Flows (in millions) (1)	\$ 127	\$ 7	-
Average gas price (per Mcf)	\$ 9.01	\$ 5.70	-

(1) Represents the standardized measure of discounted future net cash flows as calculated by an independent engineering firm utilizing extensive estimates. The estimated future net cash flow computations should not be considered to represent our estimate of the expected revenues or the current value of existing proved reserves and do not include the impact of hedge contracts.

Due to high natural gas prices and the potential for successes within the Barnett shale, more capital is being invested into the region. The competition for opportunities and goods and services may result in increased operating costs. However, our experience in the Antrim shale and our experienced Barnett shale personnel provide an advantage in addressing potential cost increases. We expect to invest a combined amount of approximately \$100 million to \$130 million in our unconventional gas business in 2006.

### Fuel Transportation and Marketing

Pipelines, Processing and Storage is in the process of expanding our storage capacity in Michigan and expanding and building new pipeline capacity to the northeast United States. Our Coal Transportation and Marketing business will seek to build our capacity to transport greater amounts of western coal and may seek to expand into coal terminals.

Significant portions of the electric and gas marketing and trading portfolio are economically hedged. The portfolio includes financial instruments and gas inventory, as well as owned and contracted natural gas pipelines and storage capacity positions. Most financial instruments are deemed derivatives, whereas the gas inventory, pipelines and storage assets are not derivatives. As a result, this segment may experience dramatic earnings volatility as derivatives are marked to market without revaluing the underlying non-derivative contracts and assets. This results in gains and losses that are recognized in different accounting periods. We incur gains or losses in one period that are subsequently reversed when transactions are settled.

During 2005, our earnings were negatively impacted by the economically favorable decision in early 2005 to delay previously planned withdrawals from gas storage due to a decrease in the current price for natural gas and an increase in the forward price for natural gas. The financial impact of this timing difference has begun to reverse as the gas is withdrawn from storage in the current storage cycle and is sold at prices significantly in excess of the cost of gas in storage. In addition, we entered into forward power contracts to economically hedge certain physical and capacity power contracts. Some of these underlying contracts are not derivatives, while the related economic hedges are derivatives, and therefore marked to market. As a result, these transactions

produce the timing related earnings swings from period to period. We expect the timing difference on the forward power contracts will not be fully realized until 2007.

### Operating System and Performance Excellence Process

We continuously review and adjust our cost structure and seek improvements in our processes. Beginning in 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. Some of these cost reductions may be returned to our customers in the form of lower Power Supply Cost Recovery (PSCR) charges and the remaining amounts may impact our profitability.

As an extension of this effort, in mid-2005, we initiated a company-wide review of our operations called the Performance Excellence Process. The overarching goal has been and remains to become more competitive by reducing costs, eliminating waste and optimizing business processes while improving customer service. Many of our customers are under intense economic pressure and will benefit from our efforts to keep down our costs and their rates. Additionally, we will need significant resources in the future to invest in the infrastructure necessary to compete. Specifically, we began a series of focused improvement initiatives within our Electric and Gas Utilities, and our corporate support function.

The process will be rigorous and challenging and seeks to yield sustainable performance to our customers and shareholders. We have identified the Performance Excellence Process as critical to our long-term growth strategy. We are entering the implementation phase and expect to begin to realize the benefits from the effort in 2006. The cost to execute the Performance Excellence Process could result in non-recurring restructuring charges in 2006.

### Capital Investment

We anticipate significant capital investment across all of our business segments. Most of our capital expenditures will be concentrated within our utility segments. Our electric utility currently expects to invest approximately \$4 billion due to increased environmental requirements and reliability enhancement projects through 2010. Our gas utility currently expects to invest approximately \$900 million on system expansion, pipeline safety and reliability enhancement projects through the same period. We plan to seek regulatory approval to include these capital expenditures within our regulatory rate base.

During 2005, we began the first wave of implementation of DTE2, an enterprise resource planning system initiative to improve existing processes and to implement new core information systems. We anticipate spending \$165 million to \$190 million over the next two years as the remaining system elements are developed and business segments fully adopt DTE2.

In the future, we may build a new base-load electric generating plant. The last base load plant constructed within our electric utility

service territory was approximately twenty years ago. A recently completed study, sponsored by the MPSC, projected that Michigan may need to install 7,000 megawatts (MW) of additional capacity over the next ten years. We estimate that a new base-load plant will cost between \$1 billion and \$2 billion.

## Outlook

The next few years will be a time of rapid change for DTE Energy and for the energy industry. Our strong utility base combined with our integrated non-utility operations position us well for long-term growth. Due to the enactment of the Energy Policy Act of 2005 and the repeal of the Public Utility Holding Company Act of 1935 there are fewer barriers to mergers and acquisitions of utility companies. We anticipate greater industry consolidation over the next few years resulting in the creation of large regional utility providers.

Looking forward, we will focus on several points that we expect will improve future performance:

- continuing to pursue regulatory stability and investment recovery for our utilities;
- managing the growth of our utility asset base;
- enhancing our cost structure across all business segments;
- improving our Electric and Gas Utility customer satisfaction;
- increasing the scale in our three non-utility business segments; and
- investing in businesses that integrate our assets and leverage our skills and expertise.

Along with pursuing a leaner organization, we expect to receive an estimated \$1.2 billion (assuming no phase-out) of synfuel cash flow through 2008, which consists of cash from operations, asset sales, and the utilization of production tax credits to reduce tax payments. Tax credit utilization in part could be extended past 2008, if taxable income is reduced from current forecasts. However, if oil prices remain at current levels or continue to increase, the estimated cash flow from the synfuel business would, as a result of production tax credit phase-out, be significantly less and would adversely impact the success of this strategy, unless we identify alternative sources of cash.

Anticipated redeployment of this expected available cash will reduce DTE Energy's debt and replace the value of synfuel operations inherent in our share price by pursuing investments in targeted energy markets. If adequate investment opportunities are not available, share repurchases may be used to build shareholder value. We remain committed to a strong balance sheet and financial coverage ratios, and paying an attractive dividend.

## Results of Operations

Net income in 2005 was \$537 million, or \$3.05 per diluted share, compared to net income of \$431 million, or \$2.49 per diluted share in 2004 and net income of \$521 million, or \$3.09 per diluted share in 2003. The comparability of earnings was impacted by our discontinued businesses, DTE Energy Technologies (Dtech), Southern Missouri Gas Company and International Transmission Company (ITC), and

the adoption of a new accounting rule in 2005 and two new accounting rules in 2003. Excluding discontinued operations and the cumulative effect of accounting changes, our income from continuing operations in 2005 was \$576 million, or \$3.27 per diluted share, compared to income of \$461 million, or \$2.66 per diluted share in 2004 and income of \$494 million, or \$2.93 per diluted share in 2003. The following sections provide a detailed discussion of our segments, operating performance and future outlook.

<i>(in Millions, except per share data)</i>	2005	2004	2003
<b>Net Income (Loss)</b>			
Electric Utility	\$ 277	\$ 150	\$ 252
Gas Utility	37	20	29
Non-utility Operations:			
Power and Industrial Projects	308	179	197
Unconventional Gas Production	4	6	12
Fuel Transportation and Marketing	2	118	69
Corporate & Other	(52)	(12)	(65)
Income (Loss) from Continuing Operations:			
Utility	314	170	281
Non-utility	314	303	278
Corporate & Other	(52)	(12)	(65)
	576	461	494
Discontinued Operations	(36)	(30)	54
Cumulative Effect of Accounting Changes	(3)	-	(27)
<b>Net Income</b>	<b>\$ 537</b>	<b>\$ 431</b>	<b>\$ 521</b>
<b>Diluted Earnings Per Share</b>			
Total Utility	\$ 1.78	\$.98	\$ 1.67
Non-utility Operations	1.78	1.75	1.65
Corporate & Other	(.29)	(.07)	(.39)
Income from Continuing Operations	3.27	2.66	2.93
Discontinued Operations	(.20)	(.17)	.32
Cumulative Effect of Accounting Changes	(.02)	-	(.16)
<b>Net Income</b>	<b>\$ 3.05</b>	<b>\$ 2.49</b>	<b>\$ 3.09</b>

The earnings per share of any segment does not represent a direct legal interest in the assets and liabilities allocated to any one segment but rather represents a direct or indirect equity interest in DTE Energy's assets and liabilities as a whole.

## Electric Utility

Our Electric Utility segment consists of Detroit Edison, which is engaged in the generation, purchase, distribution and sale of electricity to approximately 2.2 million customers in southeastern Michigan.

*Factors impacting income:* Our net income increased \$127 million to \$277 million in 2005 from \$150 million in 2004. 2004 net income decreased \$102 million from \$252 million in 2003. These results primarily reflect higher rates due to the November 2004 MPSC final rate order, return of customers from the electric Customer Choice program, warmer weather and lower operations and maintenance expenses in 2005, partially offset by a portion of higher fuel and purchased power costs, which were unrecoverable as a result of residential rate caps (which expired January 1, 2006), and increased depreciation and amortization expenses.

<i>(in Millions)</i>	2005	2004	2003
Operating Revenues	\$ 4,462	\$ 3,568	\$ 3,695
Fuel and Purchased Power	1,590	885	939
Gross Margin	2,872	2,683	2,756
Operation and Maintenance	1,308	1,395	1,332
Depreciation and Amortization	640	523	473
Taxes Other Than Income	241	249	257
Asset (Gains) and Losses, Net	(26)	(1)	20
Operating Income	709	517	674
Other (Income) and Deductions	283	303	277
Income Tax Provision	149	64	145
Net Income	\$ 277	\$ 150	\$ 252
Operating Income as a Percent of Operating Revenues	16%	14%	18%

Gross margins increased \$189 million during 2005 and declined \$73 million in 2004. Operating revenues increased due to higher demand resulting from warmer weather in 2005 and increased rates due to the November 2004 MPSC final rate order, partially offset by unrecovered power supply costs as a result of residential rate caps (which expired January 1, 2006) and a poor Michigan economy in 2005. Gross margins were favorably impacted by decreased electric Customer Choice penetration, whereby Detroit Edison lost 12% of retail sales to electric Customer Choice customers in 2005 and 18% of such sales during 2004 as retail customers migrated back to Detroit Edison as their electric generation provider rather than remaining with alternative suppliers. The following table displays changes in various gross margin components relative to the comparable prior period:

<i>(in Millions)</i>	2005	2004
<b>Increase (Decrease) in Gross Margin Components Compared to Prior Year</b>		
Weather related margin	\$ 166	\$ (25)
MPSC 2004 rate orders	116	22
Unrecovered power supply costs - residential customers	(73)	-
Transmission charges (1)	(93)	-
Electric Customer Choice program	79	(82)
Service territory economic performance	(23)	9
Other, net	17	3
Increase (decrease) in gross margin	\$ 189	\$ (73)

(1) Transmission expenses were recorded in operation and maintenance expense in 2004.

Operating revenues and fuel and purchased power costs increased in 2005 reflecting a \$8.79 per megawatthour of electricity (MWh) (58%) increase in fuel and purchased power costs during the year. Fuel and purchased power costs are a pass-through with the reinstatement of the PSCR mechanism, except for residential customers whose rate caps expired in January 2006.

The increase in power supply costs was driven by higher seasonal demand, higher purchased power rates, higher coal prices and increased power purchases due to weather and plant outages. Pursuant to the MPSC final rate order, transmission expense,

previously recorded in operation and maintenance expenses in 2004, is now reflected in purchased power expenses. The PSCR mechanism provides related revenues for the transmission expense.

The decline in 2004 revenues was partially offset by increased base rates resulting from the interim and final rate orders. Revenues in 2004 were adversely impacted by reduced cooling demand resulting from mild summer weather. In addition, operating revenues and fuel and purchased power costs decreased in 2004 reflecting a \$1.27 per MWh (8%) decline in fuel and purchased power costs. 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, 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. Since fuel and purchased power costs are a pass-through with the reinstatement of the PSCR in 2004, a decrease affects both revenues and fuel and purchased power costs but does 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.

<i>(in Thousands of MWh)</i>	2005	2004	2003
<b>Power Generated and Purchased</b>			
Power Plant Generation			
Fossil	40,756 73 %	39,432 75 %	38,052 72 %
Nuclear	8,754 16	8,440 16	8,114 16
	49,510 89	47,872 91	46,166 88
Purchased Power	6,378 11	4,650 9	6,354 12
System Output	55,888 100 %	52,522 100 %	52,520 100 %
Less Line Loss and Internal Use	(3,205)	(3,574)	(3,248)
Net System Output	52,683	48,948	49,272
<b>Average Unit Cost (\$/MWh)</b>			
Generation (1)	\$ 15.47	\$ 12.98	\$ 12.89
Purchased Power	\$ 89.37	\$ 37.06	\$ 41.73
Overall Average Unit Cost	\$ 23.90	\$ 15.11	\$ 16.38

(1) Represents fuel costs associated with power plants.

<i>(in Thousands of MWh)</i>	2005	2004	2003
Electric Sales			
Residential	16,812	15,081	15,074
Commercial	15,618	13,425	15,942
Industrial	12,317	11,472	12,254
Wholesale	2,329	2,197	2,241
Other	390	401	402
	47,466	42,576	45,913
Interconnection sales (1)	5,217	6,372	3,359
Total Electric Sales	52,683	48,948	49,272
Electric Deliveries			
Retail and Wholesale	47,466	42,576	45,913
Electric Choice	6,760	9,245	6,193
Electric Choice - Self Generators (2)	518	595	1,088
Total Electric Sales and Deliveries	54,744	52,416	53,194

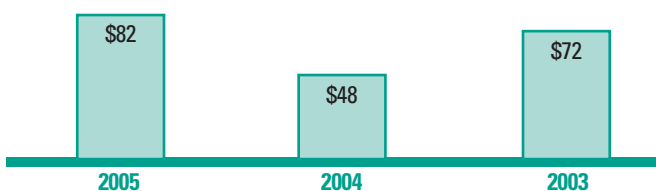
(1) Represents power that is not distributed by Detroit Edison.

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

*Operation and maintenance* expense decreased \$87 million in 2005 and increased \$63 million in 2004. As a result of the MPSC final rate order, transmission and Midwest Independent System Operator (MISO) expenses in 2005 are now included in purchased power expense with related revenues recorded through the PSCR mechanism. In addition, as a result of the MPSC final rate order, merger interest is no longer allocated from the DTE Energy parent company to Detroit Edison. Partially offsetting the lack of merger interest expense and the transmission expense accounting reclassification were higher 2005 storm expenses.

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.

#### Storm Restoration Costs (in millions)



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 cost trend rates, and increased reserves for uncollectible accounts receivable, reflecting high past-due amounts attributable to economic conditions. In addition, we accrued a refund due from the Midwest Independent System Operator in 2004 for transmission services.

*Depreciation and amortization* expense increased \$117 million in 2005 and increased \$50 million in 2004. The increases reflect the income effect of recording regulatory assets, which lowered depreciation and amortization expenses. The regulatory asset deferrals totaled \$46 million in 2005, \$107 million in 2004 and \$153 million in 2003, representing net stranded costs and other costs we believe are recoverable under Public Act (PA) 141. Additionally, higher 2005 sales volumes compared to 2004 resulted in greater amortization of regulatory assets.

*Asset (gains) and losses*, net increased \$25 million in 2005 as a result of our sale of land near our headquarters.

*Other income and deductions* expense decreased \$20 million in 2005 and increased \$26 million in 2004. The 2005 decrease is due primarily to lower interest expense as a result of lower interest rates and a favorable adjustment related to tax audit settlements. 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.

**Outlook** - We continue to improve the operating performance of Detroit Edison. During the past year we have resolved many of our regulatory issues and continue to pursue additional regulatory solutions for structural problems within our competitive environment, mainly electric Customer Choice and the need to adjust rates for each customer class to reflect the full cost of service.

Concurrently, we will move forward in our efforts to improve performance. Looking forward, additional issues, such as rising prices for coal, uranium and health care, continued under-performance of Michigan's economy and capital spending, will result in us taking meaningful action to address our costs while continuing to provide quality customer service. We will utilize the DTE Operating System and the Performance Excellence Process to seek opportunities to improve productivity, remove waste, decrease our costs, while improving customer satisfaction.

Long term, we will be required to invest an estimated \$2.4 billion on emission controls through 2018. Should we be able to recover these costs in future rate cases, we may experience a growth in earnings. Additionally, our service territory may require additional generation capacity. A new base-load generating plant has not been built within the State of Michigan in the last 20 years. Should our regulatory environment be conducive to such a significant capital expenditure, we may build or expand a new base-load facility, with an estimated cost of \$1 billion to \$2 billion.

The following variables, either in combination or acting alone, will impact our future results:

- amount and timing of cost recovery allowed as a result of regulatory proceedings, related appeals, or new legislation;
- our ability to reduce costs;
- variations in market prices of power, coal and gas;
- plant performance;
- economic conditions within the state of Michigan;
- weather, including the severity and frequency of storms; and
- levels of customer participation in the electric Customer Choice program.

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 adequately addressed. We will accrue as regulatory assets any future unrecovered generation-related fixed costs (stranded costs) due to electric Customer Choice that we believe are recoverable under Michigan legislation and MPSC orders. We cannot predict the outcome of these matters. See Note 4.

## Gas Utility

Our Gas Utility segment consists of MichCon and Citizens Fuel Gas Company (Citizens), natural gas utilities subject to regulation by the MPSC. MichCon is engaged in the purchase, storage, transmission, distribution and sale of natural gas to approximately 1.3 million residential, commercial and industrial customers in the State of Michigan. MichCon also has subsidiaries involved in the gathering and transmission of natural gas in northern Michigan. MichCon operates one of the largest natural gas distribution and transmission systems in the United States. Citizens distributes natural gas in Adrian, Michigan.

*Factors impacting income:* Gas Utility's net income increased \$17 million in 2005 and declined \$9 million in 2004, compared to the prior year, primarily reflecting the impact of the MPSC's April 2005 gas cost recovery and final rate orders.

The MPSC final gas rate order disallowed recovery of 90% of the costs of a computer billing system that was in place prior to DTE Energy's acquisition of MCN Energy in 2001. MichCon impaired this asset by approximately \$42 million in the first quarter of 2005. This disallowance was not reflected at the DTE Energy level since this impairment was previously reserved at the time of the MCN acquisition in 2001.

<i>(in Millions)</i>	2005	2004	2003
Operating Revenues	\$ 2,138	\$ 1,682	\$ 1,498
Cost of Gas	1,490	1,071	909
Gross Margins	648	611	589
Operation and Maintenance	424	403	371
Depreciation and Amortization	95	103	101
Taxes Other Than Income	43	49	52
Asset (Gains) and Losses, Net	4	(3)	-
Operating Income	82	59	65
Other (Income) and Deductions	47	48	36
Income Tax Benefit	(2)	(9)	-
Net Income	\$ 37	\$ 20	\$ 29
Operating Income as a Percent of Operating Revenues	4 %	4 %	4 %

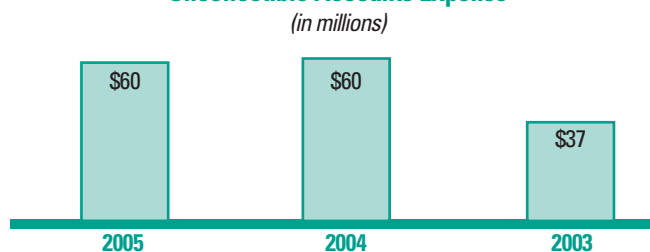
Gross margins increased \$37 million in 2005 and increased \$22 million in 2004, compared to the prior year. Gross margins in 2005 were favorably affected by higher base rates as a result of the interim and final gas rate orders, and revenue associated with the uncollectible expense tracking mechanism authorized by the MPSC. In April 2005, the MPSC issued an order in the 2002 GCR reconciliation case that disallowed \$26 million representing unbilled revenues at December 2001. We recorded the impact of the disallowance during the first quarter of 2005. Operating revenues and cost of gas increased in 2005 reflecting higher gas prices which are recoverable from customers through the GCR mechanism. The 2004 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 GCR plan case. See Note 4.

	2005	2004	2003
<b>Gas Markets (in Millions)</b>			
Gas sales	\$ 1,860	\$ 1,435	\$ 1,242
End user transportation	134	119	136
	1,994	1,554	1,378
Intermediate transportation	58	56	51
Other	86	72	69
	\$ 2,138	\$ 1,682	\$ 1,498
<b>Gas Markets (in Bcf)</b>			
Gas sales	168	173	181
End user transportation	157	145	152
	325	318	333
Intermediate transportation	432	536	576
	757	854	909

*Operation and maintenance* expense increased \$21 million in 2005 and \$32 million in 2004. The 2005 increase is primarily due to the impact of the MPSC rate order that disallowed certain environmental expenses that had been recorded as a regulatory asset and its requirement to defer negative pension expense as a regulatory liability. For 2005, uncollectible accounts receivables expense remained consistent with 2004, reflecting higher past due amounts attributable to an increase in gas prices, continued weak economic conditions and inadequate government-sponsored assistance for low-income customers. The 2005 final rate order provided revenue for an uncollectible expense tracking mechanism to mitigate some of the effect of increasing uncollectible expense. The increase in operation and maintenance expense was partially offset by the DTE Energy parent company no longer allocating merger-related interest to MichCon effective in April 2005, as a result of the disallowance of those costs in the April 2005 final rate order. The increase was also partially offset by a decline in accruals for injuries and damages during 2005.

The 2004 period reflects 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



*Asset (gains) and losses, net* declined \$7 million in 2005 as a result of a write-off of certain computer equipment and related depreciation resulting from the April 2005 final rate order.

*Income taxes* increased by \$7 million in 2005 and decreased by \$9 million in 2004 due to variations in pre-tax earnings.

*Outlook* - Operating results are expected to vary as a result of factors such as regulatory proceedings, weather, changes in economic conditions, cost containment efforts and process improvements. Higher gas prices and economic conditions have resulted in continued pressure on receivables and working capital requirements partially mitigated by the GCR mechanism. We believe our allowance for doubtful accounts is based on reasonable estimates. In the April 2005 final gas rate order, the MPSC adopted MichCon's proposed tracking mechanism for uncollectible accounts receivable. Each year, MichCon will file an application comparing its actual uncollectible expense for the prior calendar year to its designated revenue recovery of approximately \$37 million. Ninety percent of the difference will be refunded or surcharged after an annual reconciliation proceeding before the MPSC.

## Non-utility Operations

### Power and Industrial Projects

Power and Industrial Projects is comprised of Coal-Based Fuels, On-Site Energy Projects, Non-Utility Power Generation, Landfill Gas Recovery and Waste Coal Recovery. Coal-Based Fuels operations include producing synthetic fuel from nine synfuel plants and producing coke from two 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 production tax credits. On-Site Energy Projects include pulverized coal injection, power generation, steam production, chilled water production, wastewater treatment and compressed air supply. Non-Utility Power Generation owns and operates four gas-fired peaking electric generating plants and manages and operates one additional gas-fired power plant under contract. Landfill Gas Recovery develops, owns and operates landfill recovery systems throughout the United States. Waste Coal Recovery uses proprietary technology to produce high quality coal products from fine coal slurries typically discarded from coal mining operations.

*Factors impacting income:* Net income increased \$129 million in 2005 and decreased \$18 million in 2004, compared to 2003. These results primarily reflect higher gains recognized from selling interests in our synfuel plants, gains and losses on synfuel hedges, and varying levels of production tax credits.

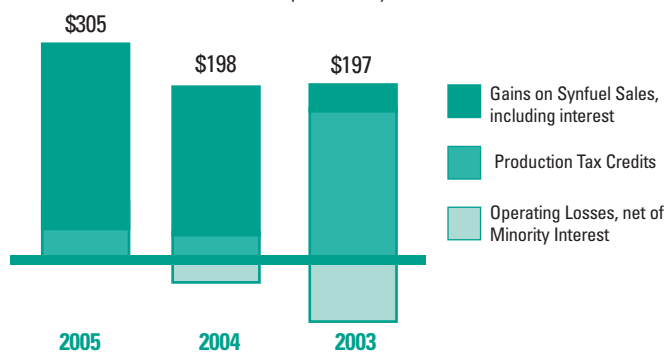
<i>(in Millions)</i>	2005	2004	2003
Operating Revenues	\$ 1,356	\$ 1,100	\$ 938
Operation and Maintenance	1,497	1,216	1,108
Depreciation and Amortization	107	89	90
Taxes other than Income	34	16	18
Asset (Gains) and Losses, Net	(368)	(215)	(114)
Operating Income (Loss)	86	(6)	(164)
Other (Income) and Deductions	(30)	(15)	1
Minority Interest	(281)	(212)	(91)
Income Taxes			
Provision (Benefit)	144	80	(30)
Production Tax Credits	(55)	(38)	(241)
	89	42	(271)
Net Income	\$ 308	\$ 179	\$ 197

*Operating revenues* increased \$256 million in 2005 and \$162 million in 2004 primarily reflecting higher synfuel sales due to increased production, and higher market prices for our coke production. Operating expenses associated with synfuel projects exceed operating revenues and therefore generate operating losses, which have been more than offset by the resulting production 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 have become fixed or determinable and collectibility is reasonably assured.

The improvement in 2004 synfuel revenues results from increased production due to additional sales of project interests in 2004, reflecting our strategy to produce synfuel primarily from plants in which we had sold interests in order to optimize income and cash flow.

### Synfuel Earnings

*(in millions)*



Revenues from on-site energy projects increased in 2005, reflecting the addition of new facilities, 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 \$281 million in 2005 and \$108 million in 2004, reflecting costs associated with increased synfuel production, 2005 acquisitions of three on-site energy projects and coke operations. Partially offsetting 2004 higher synfuel operating costs was the recording of insurance proceeds associated with an accident at one of our coke batteries.

*Asset (gains) and losses*, net increased \$153 million in 2005 and \$101 million in 2004. The improvements are due to increased production and sales volume from our synfuel projects. To economically 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. The derivative contracts are marked to market with changes in their fair value recorded as an adjustment to synfuel gains. We recorded 2005 synfuel hedge mark to market gains of \$48 million, compared to 2004 mark to market losses of \$12 million. See Note 12.

*Minority interest* increased \$69 million in 2005 and \$121 million in 2004, reflecting our partners' share of operating losses associated with synfuel operations. The sale of interests in our synfuel facilities during prior periods resulted in allocating a larger percentage of such losses to our partners.

*Income taxes* increased \$47 million in 2005 and \$313 million in 2004. The increase in 2005 reflects higher taxable earnings, partially offset by higher production tax credits. The increase in 2004 reflects higher taxable earnings and a decline in the level of production tax credits due to the sale of interests in synfuel facilities.

*Outlook* - We may sell additional interests in our synfuel plants and take actions to protect our expected synfuel cash flows from the risk of an oil price-related phase-out. Synfuel-related tax credits expire on December 31, 2007.

In the third quarter of 2005, we executed an agreement to purchase five on-site energy projects and closed on three of the projects in 2005.

Power and Industrial Projects 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 2006.

Production tax credits generated by our Coal-Based Fuels and Landfill Gas Recovery businesses are subject to the same phase out risk if domestic crude oil prices reach certain levels. See Note 13.

### Unconventional Gas Production

Unconventional Gas Production is primarily engaged in natural gas exploration, development and production. Our Unconventional Gas Production business produces gas from the Antrim and Barnett shales and sells most of the gas to the Fuel Transportation and Marketing segment.

Factors impacting income: Net income decreased \$2 million in 2005 and decreased \$6 million in 2004. The decline in 2005 is due to higher operating and Michigan severance tax expenses. The decline in 2004 is due to increased interest costs and a gain that was recognized in 2003 as a result of a sale of a non-core asset.

<i>(in Millions)</i>	2005	2004	2003
Operating Revenues	\$ 74	\$ 71	\$ 70
Operation and Maintenance	30	27	22
Depreciation and Amortization	20	18	17
Taxes Other Than Income	11	7	7
Operating Income	13	19	24
Other (Income) and Deductions	8	10	7
Income Tax Provision	1	3	5
Net Income	\$ 4	\$ 6	\$ 12

*Operating revenues* increased \$3 million in 2005 and increased \$1 million in 2004 due primarily to higher gas prices.

*Operations and maintenance expenses* increased \$3 million in 2005 and increased \$5 million in 2004. Increases are associated with the addition of approximately 300 producing wells during the three year period. The 2004 increase is also due to a \$6 million pretax gain on the sale of non-core assets recorded in 2003.

*Taxes other than income* increased \$4 million in 2005 due to higher severance taxes associated with gas price increases.

*Other (income) and deductions* decreased \$2 million in 2005 and increased \$3 million in 2004. Interest expense was the primary contributor to the variances.

*Outlook* - We expect to continue to develop our proved areas, test unproved areas and prudently add new acreage in Michigan and Texas. During 2005 we increased our acreage holdings by 38,437 acres (24,852 net of the interest of others) in the Antrim and Barnett shales. Results from the Barnett shale test wells drilled during 2005 are expected during the first half of 2006. We expect to invest a combined amount of approximately \$100 million to \$130 million in our unconventional gas business in 2006.

### Fuel Transportation and Marketing

Fuel Transportation and Marketing consists of DTE Energy Trading, Coal Transportation and Marketing and the Pipelines, Processing and Storage business.

DTE Energy Trading focuses on physical power and gas marketing, structured transactions, enhancement of returns from DTE Energy's power plants and the optimization of contracted natural gas pipelines and storage capacity positions. Our customer base is predominantly utilities, local distribution companies, large industrials, and other marketing and trading companies. We enter into derivative financial instruments as part of our marketing and hedging activities. 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. We utilize forwards, futures, swaps and option contracts to mitigate risk associated with our marketing and trading activity as well as for proprietary trading within defined risk guidelines. DTE Energy Trading is integral in providing commodity risk management services to the other unregulated businesses within DTE Energy.

Coal Transportation and Marketing 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. We recently initiated a new business line, coal mine methane extraction, in which we recover methane gas from mine voids for processing and delivery to natural gas pipelines, industrial users, or for small power generation projects.

Pipelines, Processing and Storage 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 operations.

*Factors impacting income:* Net income decreased \$116 million in 2005, consisting primarily of a \$131 million decline at DTE Energy Trading associated with mark-to-market losses on gas storage hedges. Net income increased \$49 million in 2004, consisting primarily of a \$47 million improvement at DTE Energy Trading. The comparability of results is impacted by a \$74 million one-time pretax gain from a contract modification/termination recorded in the first quarter of 2004 and significant 2005 mark-to-market losses on derivative contracts used to economically hedge our gas in storage and forward power contracts.

<i>(in Millions)</i>	2005	2004	2003
Operating Revenues	\$ 1,684	\$ 1,254	\$ 1,061
Fuel, Purchased Power and Gas	970	473	643
Operation and Maintenance	710	596	334
Depreciation and Amortization	7	6	4
Taxes Other Than Income	3	4	2
Operating Income (Loss)	(6)	175	78
Other (Income) and Deductions	(7)	(7)	(32)
Income Tax Provision (Benefit)	(1)	64	41
Net Income	\$ 2	\$ 118	\$ 69

*Operating revenues* increased \$430 million in 2005 and increased \$193 million in 2004. Both Coal Transportation and Marketing and DTE Energy Trading experienced revenue growth in 2005 due to higher demand, higher commodity pricing, the sale of emission credits and increased trading volume. Comparability of 2005 to 2004 is affected because our trading operations recorded an adjustment in 2004 that increased revenue by \$86 million related to the modification of a future purchase commitment under a transportation agreement with an interstate pipeline company. See Note 13.

Coal Transportation and Marketing revenues in 2004 were 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 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.

*Fuel, purchased power* and gas increased \$497 million in 2005 and decreased \$170 million in 2004. During 2005, our earnings have been negatively impacted by the economically favorable decision in early 2005 to delay previously planned withdrawals from gas storage due to a decrease in the current price for natural gas and an increase in the forward price for natural gas. We anticipate the financial impact of this timing difference will reverse when the gas is withdrawn from storage in the current storage cycle and is sold at prices significantly in excess of the cost of gas in storage. In addition, we entered into forward power contracts to economically hedge certain physical and capacity power contracts. We expect the timing difference on the forward power contracts will be fully realized by the end of 2007.

In 2004, our trading operations recorded a gas inventory adjustment that increased expense by \$12 million related to the termination of a long-term gas exchange agreement with an interstate pipeline company. See Note 13. 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.

*Operation and maintenance expenses* increased \$114 million in 2005 and increased \$262 million in 2004. During 2005, our Coal Transportation and Marketing business experienced higher throughput volumes and increased prices for coal. The increase in 2004 was due primarily to increased coal purchases and increased lease expense.

*Other (income) and deductions* for 2005 remained consistent with 2004, and decreased \$25 million in 2004. The decline in 2004 is primarily due to gains recorded in 2003 from selling our 16% pipeline interest in the Portland Natural Gas Transmission System.

*Income tax provision* decreased \$65 million in 2005 and increased \$23 million in 2004 due to variations in earnings.

*Outlook* - We expect to continue to grow our Coal Services and DTE Energy Trading businesses 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 and mitigate risks.

We expect to continue to grow our Pipeline, Processing and Storage business by expanding existing assets and developing new assets. Pipelines, Processing and Storage received MPSC approval in September 2005 and executed long-term contracts for a capacity expansion at one of our Michigan storage fields that will facilitate an additional 14 Bcf of storage service sales starting in April 2006. Vector Pipeline has secured long-term market commitments to support an expansion project, for approximately 200 MMcf per day, with a projected in-service date of November 2007. Vector Pipeline expects to receive Federal Energy Regulatory Commission (FERC) approval in the second quarter of 2006. The Millennium Pipeline filed an application for FERC approval in August 2005. In addition, Pipeline, Processing and Storage owns a 10.5% interest in the Millennium Pipeline and is currently negotiating to increase its equity interest.

Significant portions of the Fuel Transportation and Marketing portfolio are economically hedged. The portfolio includes financial instruments and gas inventory, as well as capacity positions of natural gas storage and pipelines and power transmission contracts. The financial instruments are deemed derivatives, whereas the gas inventory, pipelines and storage assets are not derivatives. As a result, we 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 does not coincide with the calendar and fiscal year, but runs annually from April of one year to March of the next year. Our strategy is to economically hedge the price risk of storage with over-the-counter forwards and futures. 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 generally 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.

## Corporate & Other

Corporate & Other includes various corporate support functions such as accounting, legal and information technology services. As these functions essentially support the entire Company, their costs are fully allocated to the various segments based on services utilized.

Therefore the effect of the allocation on each segment can vary from year to year. Additionally, Corporate & Other holds certain non-utility debt, assets held for sale, and energy related investments.

*Factors impacting income:* Corporate & Other results declined \$40 million in 2005, compared to a \$53 million improvement in 2004. The 2005 decline was primarily a result of the parent company not allocating merger interest to Detroit Edison and MichCon. Partially offsetting 2005 increased expenses were reduced Michigan Single Business Taxes and gains on the sale of non-strategic assets. 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, as well as lower Michigan Single Business Taxes, resulting from tax saving initiatives. Corporate & Other also benefited from lower financing costs.

## Discontinued Operations

*DTE Energy Technologies (Dtech)* - We own Dtech, which assembles, markets, distributes and services distributed generation products, provides application engineering, and monitors and manages on-site generation system operations. In July 2005, management approved the restructuring of this business resulting in the identification of certain assets and liabilities to be sold or abandoned, primarily associated with standby and continuous duty operations. We recognized a net of tax restructuring loss of \$23 million during the third quarter of 2005 primarily representing the write down to fair value of the assets of Dtech, less costs to sell, and the write-off of goodwill. As we execute the restructuring plan, there may be adjustments to amounts recorded related to the impairment and exit costs. We anticipate completing the restructuring plan by mid-2006.

*Southern Missouri Gas Company* - We owned 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 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, 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. Regulatory approval was received in April 2005 and the sale closed in May 2005. During the second quarter of 2005, we recognized a net of tax gain of \$2 million.

*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. Through December 31, 2004, we recorded a gain of \$58 million (net of tax). During the second quarter of 2005, the gain was adjusted to \$56 million (net of tax).

See Note 3.

## Cumulative Effect Of Accounting Changes

In the fourth quarter of 2005, we adopted additional new accounting rules for asset retirement obligations. The cumulative effect of adopting these new accounting rules reduced 2005 earnings by \$3 million.

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.

## Capital Resources and Liquidity

DTE Energy and its subsidiaries require cash to operate and 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, retire and pay interest on long-term debt and pay dividends. Our strategic direction anticipates base level capital investments and expenditures for existing businesses in 2006 of up to \$1.2 billion. The capital needs of our utilities will increase due primarily to environmental related expenditures. We may spend an additional \$200 million to \$400 million on growth-related projects within our non-regulated businesses in 2006.

Capital spending for general corporate purposes will increase in 2006, primarily as a result of DTE2 and environmental spending. During 2005, we began the first wave of implementation of DTE2, an enterprise resource planning system initiative to improve existing processes and to implement new core information systems. We anticipate spending \$165 million to \$190 million over the next two years as the remaining system elements are developed and business segments fully adopt DTE2.

We anticipate environmental capital expenditures of approximately \$250 million in 2006 and up to approximately \$2.3 billion of future capital expenditures to satisfy both existing and proposed new requirements.

We expect non-utility capital spending will approximate \$200 million to \$400 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 2006 totals approximately \$682 million.

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

<i>(in Millions)</i>	2005	2004	2003
<b>Cash and Cash Equivalents</b>			
Cash Flow From (Used For)			
Operating activities:			
Net income	\$ 537	\$ 431	\$ 521
Depreciation, depletion and amortization	872	744	691
Deferred income taxes	147	129	(220)
Gain on sale of ITC, synfuel and other assets, net	(405)	(236)	(228)
Working capital and other	(150)	(73)	186
	<b>1,001</b>	<b>995</b>	<b>950</b>
Investing activities:			
Plant and equipment expenditures - utility	(850)	(815)	(679)
Plant and equipment expenditures - non-utility	(215)	(89)	(72)
Business acquisitions, net of cash acquired	(50)	-	-
Proceeds from sale of ITC, synfuels and other assets, net of cash divested	409	325	758
Restricted cash and other investments	(96)	(102)	3
	<b>(802)</b>	<b>(681)</b>	<b>10</b>
Financing activities:			
Issuance of long-term debt and common stock	1,041	777	571
Redemption of long-term debt	(1,266)	(759)	(1,208)
Short-term borrowings, net	437	33	(44)
Repurchase of common stock	(13)	-	-
Dividends on common stock and other	(366)	(363)	(358)
	<b>(167)</b>	<b>(312)</b>	<b>(1,039)</b>
Net Increase (Decrease) in Cash and Cash Equivalents	\$ 32	\$ 2	\$ (79)

## 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, 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 approximately \$1.2 billion of cash during 2006-2008 (assuming no phase-out), to new startups. These new start-ups include our unconventional gas and waste coal recovery businesses, which we are growing and, if successful, could require significant investment.

Cash from operations totaling \$1.001 billion in 2005 was up \$6 million from the comparable 2004 period. The operating cash flow comparison reflects an increase of over \$83 million in net income, after adjusting for non-cash items (depreciation, depletion, amortization, deferred taxes and gains), substantially offset by a \$77 million increase in working capital and other requirements. Most of the improvement was driven by higher net income at Detroit Edison which was the

result of improved revenues and gross margin stemming from higher rates granted in the 2004 rate orders, warmer weather, and lower customer choice penetration. The offsetting increase in working capital requirements was driven by a \$127 million PSCR under-recovery in 2005 as compared to a \$112 million over-recovery in 2004. Working capital requirements also reflect the higher cost of gas at MichCon and our Fuel Transportation and Marketing segment. MichCon's working capital and other requirements were \$136 million higher in 2005 compared to 2004 primarily due to the impact of higher gas costs. This impact was reflected by accounts receivable balances that were \$198 million higher at December 31, 2005 than the previous year at MichCon. The increase in working capital requirements was mitigated by lower income tax payments in 2005 and company initiatives to improve cash flow, including better inventory management, cash sales transactions and the utilization of letters of credit.

Our net operating cash flow in 2004 was \$995 million, reflecting a \$45 million increase from 2003. 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.

*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, partially offset by higher cash requirements on environmental and other utility capital as well as growth investments in our non-utility portfolio. We are likely to incur costs associated with implementation of our Performance Excellence Process, but we expect to realize long term cost savings. We also may be impacted by the delayed collection of underrecoveries of our PSCR and GCR costs and electric and gas accounts receivable as a result of recent MPSC orders. Gas prices are likely to be a source of volatility with regard to working capital requirements for the foreseeable future. We are continuing our efforts to identify opportunities to improve cash flow through working capital improvement initiatives.

Operating cash flow from our utilities is expected to increase in 2006. Due to the structure of the interim and final rate orders, we will begin to realize the full benefits of interim and final rate relief in 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 cash generation and conservation.

Assuming no production tax credit phase-out, cash flows from our synfuel business are expected to be approximately \$400 million, \$500 million and \$300 million in 2006, 2007 and 2008, respectively, including \$300 million tax credit carryforward utilization by DTE Energy. 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 to improve our current credit rating and outlook, and to replace the value of synfuel operations currently inherent in our share price. However, if oil prices remain at current levels or increase throughout 2006, the expected cash flow from the synfuel business would be less and could adversely impact the success of this strategy, unless the Company identifies alternative sources of cash. Synfuel cash flow consists of variable and fixed payments from partners, proceeds from option and other contracts used to protect us from risk of loss from a tax credit phase-out and the use of prior years' tax credit carry-forwards. Since 2004, we have spent approximately \$105 million hedging our future synfuel cash flow and may spend up to \$50 million in 2006.

Our other operating non-utility businesses are expected to contribute approximately \$500 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 2005, which will have the impact of lowering cash flow in 2006.

### 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 realize 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 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. We start with 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 outflows relating to investing activities increased \$121 million in 2005 and \$691 million in 2004, compared to the prior year. The 2005 change was primarily due to increased capital expenditures, partially offset by higher synfuel proceeds. Spending

on growth project investments increased \$123 million in 2005 while spending on environmental projects was \$44 million higher than the 2004 period. The 2004 change was 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 change was due to variations in cash contractually designated for debt service.

Longer term, with the expected improvement at our utilities and assuming 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 borrowing and long-term financing 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.

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 \$145 million in 2005 and improved \$727 million in 2004, compared to the prior periods. The improvement in 2005 was primarily driven by the issuance of common stock which resulted from the conversion of our equity security units. The change in 2004 was primarily due to higher issuances of long-term debt and levels of short-term debt borrowings which exceeded the requirements of long-term debt redemptions.

See Note 9 - Long-Term Debt and Preferred Securities and Note 10 - Short-Term Credit Arrangements and Borrowings for more information regarding financing activities.

Amounts available under shelf registrations include \$500 million at DTE Energy, \$250 million at Detroit Edison and \$200 million at MichCon. In 2006, we plan on filing new shelf registration statements for DTE Energy and Detroit Edison.

Common stock issuances or repurchases can also be a source or use of cash. In January 2005, we announced that the DTE Energy Board of Directors 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. No share repurchases were made in 2005. As of January 1, 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. In August 2005, we issued 3.7 million shares of common stock in conjunction with the settlement of the stock purchase component of our equity security units.

## Contractual Obligations

The following table details our contractual obligations for debt redemptions, leases, purchase obligations and other long-term obligations as of December 31, 2005:

<i>(in Millions)</i>	Total	Less Than 1 Year	1-3 Years	4-5 Years	After 5 Years
<b>Contractual Obligations</b>					
Long-term debt:					
Mortgage bonds,					
notes and other	\$ 5,821	\$ 577	\$ 634	\$ 1,305	\$ 3,305
Securitization bonds	1,400	105	363	290	642
Equity-linked securities	175	-	175	-	-
Trust preferred-linked securities	289	-	-	-	289
Capital lease obligations	124	16	43	24	41
Interest	6,035	455	1,222	673	3,685
Operating leases	536	63	128	61	284
Electric, gas, fuel, transportation and storage purchase obligations (1)	6,333	3,718	1,747	188	680
Other long-term obligations	337	153	117	21	46
<b>Total obligations</b>	<b>\$ 21,050</b>	<b>\$ 5,087</b>	<b>\$ 4,429</b>	<b>\$ 2,562</b>	<b>\$ 8,972</b>

(1) 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 are 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 the company may affect our ability to access these funding sources or cause an increase in the return required by investors.

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 \$536 million at December 31, 2005. Additionally, upon a downgrade, 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 credit rating agency 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.

Entity	Description	Credit Rating Agency		
		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

## 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, production 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:

<i>(in Millions)</i>	
<b>Utility</b>	
Detroit Edison (1)	\$ (154)
MichCon	(43)
<b>Total</b>	<b>\$ (197)</b>

(1) 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. See 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.

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.

### Production Tax Credits

We generate production tax credits from our synfuel, coke battery and landfill gas recovery operations. We recognize earnings as tax credits are generated at our facilities in one of two ways. First, 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. Second, to the extent we generate credits to our own account, we recognize earnings through reduced tax expense.

All production tax credits are subject to audit by the IRS. However, all of our synfuel facilities have received favorable private letter rulings from the IRS with respect to their operations. Audits of five of our synfuel facilities were successfully completed in the past two years. If production 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 \$617 million in 2005, as compared to \$449 million in 2004 and \$387 million in 2003. The portion of tax credits generated for our own account was \$55 million in 2005, as compared to \$38 million in 2004 and \$241 million in 2003, with the remaining credits generated allocated to third party partners.

### Goodwill

Certain of our business units have goodwill resulting from purchase business combinations. 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, 2005, our goodwill totaled \$2.1 billion. The majority of our goodwill is allocated to our utility reporting units, with \$772 million allocated to the Gas Utility reporting unit. The value of the utility reporting units may be significantly impacted by rate orders and the regulatory environment. The Gas Utility reporting unit is comprised primarily of MichCon. We have made certain assumptions for MichCon that incorporate earnings multiples used in the cash flow valuations. These assumptions may change as regulatory and market conditions change.

We also have \$41 million of goodwill allocated to the Power and Industrial Projects reporting unit. The value of the Power and Industrial Projects reporting unit may be significantly impacted by any phase-out of tax credits related to our synfuel business. We have assumed there will be no phase-out of synfuel tax credits and will monitor the status of any potential phase-out and its impact on our valuation assumptions.

During 2005 we recorded an impairment of \$16 million to goodwill related to discontinuing the operations of Dtech.

Based on our 2005 goodwill impairment test, we determined that the fair value of our remaining operating reporting units exceed their carrying value and no impairment existed. We will continue to monitor our estimates and assumptions regarding future cash flows. 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 \$90 million in 2005, \$81 million in 2004, and \$47 million in 2003. Postretirement benefits costs for all plans were \$155 million in 2005, \$125 million in 2004, and \$118 million in 2003. Pension and postretirement benefits costs for 2005 are 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 2006 expected long-term rate of return on plan assets is based on an asset allocation assumption utilizing active investment management of 66% in equity markets, 25% in fixed income markets, and 9% 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 that 8.75% is a reasonable long-term rate of return on our plan assets for 2006. 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. Accordingly, the future value of assets will be impacted as previously deferred gains or losses are recorded. We have unrecognized net losses due to the performance of the financial markets. As of December 31, 2005, we had \$6 million of cumulative losses 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 yield curve approach and a review of bonds that receive one of the two highest ratings given by a recognized rating agency. The yield curve approach matches projected plan pension and postretirement benefit payment streams with bond portfolios reflecting actual liability duration unique to our plans. The discount rate determined on this basis decreased from 6.0% at December 31, 2004 to 5.9% at December 31, 2005. Due to recent financial market performance, lower discount rates and increased health care trend rates, we estimate that our 2006 pension costs will approximate \$80 million compared to \$96 million in 2005 and our 2006 postretirement benefit costs will approximate \$192 million compared to \$155 million in 2005. 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. In April 2005, the MPSC approved the deferral of the non-capitalized portion of MichCon's negative pension expense. MichCon will record a regulatory liability for any negative pension costs, as determined under generally accepted accounting principles.

Lowering the expected long-term rate of return on our plan assets by one-percentage-point would have increased our 2005 qualified pension costs by approximately \$24 million. Lowering the discount rate and the salary increase assumptions by one-percentage-point would have increased our 2005 pension costs by approximately \$10 million. Lowering the health care cost trend assumptions by one-percentage-point would have decreased our postretirement benefit service and interest costs for 2005 by approximately \$20 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 \$2.9 billion at December 31, 2003 to \$3.3 billion at December 31, 2004. The value at December 31, 2005 was \$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) in 2003, 2004, and 2005. 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 \$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 did not make pension contributions in 2005. We contributed \$80 million to our postretirement plans in 2004. We did not contribute to our postretirement plans in 2003 and 2005. We do not anticipate making a contribution to our qualified pension plans in 2006. At the discretion of management, we may make up to a \$120 million contribution to our postretirement plans in 2006.

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 \$20 million in 2005 and \$16 million in 2004.

See Note 14.

### **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 2004 and 2005. We believe the allowance for doubtful accounts is based on reasonable estimates. As part of the 2005 rate order for MichCon, the MPSC provided for the establishment of an uncollectible accounts tracking mechanism that partially mitigates the impact associated with MichCon uncollectible expenses. However, failure to make continued progress in collecting our past due receivables in light of rising energy prices would unfavorably affect operating results and cash flow.

### **Legal and Tax Reserves**

We are involved in various 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 and claims 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 U.S. Environmental Protection Agency (EPA) and the Michigan Department of

Environmental Quality (MDEQ) have aggressive programs to clean-up contaminated property.

## Electric Utility

*Air* - Detroit Edison is subject to EPA ozone transport and acid rain regulations that limit power plant emissions of sulfur dioxide and nitrogen oxides. In March 2005, EPA issued additional emission reduction regulations relating to ozone, fine particulate, regional haze and mercury air pollution. The new rules will lead to additional controls on fossil-fueled power plants to reduce nitrogen oxide, sulfur dioxide and mercury emissions. To comply with these requirements, Detroit Edison has spent approximately \$644 million through 2005. We estimate Detroit Edison will incur future capital expenditures of up to \$218 million in 2006 and up to \$2.2 billion of additional capital expenditures through 2018 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 was deferred in ratemaking until December 31, 2005, the expiration of the rate cap period.

The EPA has ongoing enforcement actions against several major electric utilities citing violations of 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. In October 2003, the EPA promulgated revised regulations to clarify new source review provisions going forward. Several states and environmental organizations have challenged these regulations and, in December 2003, a stay was issued until the U.S. Court of Appeals D.C. Circuit renders an opinion in the case. We cannot predict the future impact of this issue upon Detroit Edison.

*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 four to six years in additional capital expenditures to comply with these requirements.

*Contaminated Sites* - 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. We have a reserve balance of \$13 million as of December 31, 2005 for the remediation of these sites over the next several years.

## Gas Utility

*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. Gas Utility owns, or previously owned, 15 former MGP sites. Investigations have revealed contamination related to the by-products of gas manufacturing at each site. In addition to the MPG sites, Gas Utility is also in the process of cleaning up other contaminated sites. Cleanup activities associated with these sites will be conducted over the next several years. As a result of these

determinations, we have recorded liabilities of \$35 million and \$1 million for the MGPs and other contaminated sites, respectively. It is estimated that Gas Utility may incur \$5 million in expenses related to cleanup costs in 2006. While we cannot make any assurances, we believe that a cost deferral and rate recovery mechanism for the MGP sites, approved by the MPSC, will prevent these costs from having a material adverse impact on our results of operations.

In 1993, a cost deferral and rate recovery mechanism was approved by the MPSC for investigation and remediation costs incurred at former MGP sites in excess of this reserve. Gas Utility 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, Gas Utility accrued an additional liability and a corresponding regulatory asset of \$35 million during 1995. During 2005, we spent approximately \$4 million investigating and remediating these former MGP sites. In December 2005, we retained multiple environmental consultants to estimate the projected cost to remediate each MGP site. We accrued an additional \$9 million in remediation liabilities associated with two of our MGP sites, to increase the reserve balance to \$35 million at December 31, 2005.

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 thereby affect 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.

## Other

Our non-utility affiliates are subject to a number of environmental laws and regulations dealing with the protection of the environment from various pollutants. We are in the process of installing new environmental equipment at our coke battery facilities in Michigan. We expect the projects to be completed within two years at a cost of approximately \$25 million. Our other non-utility affiliates are substantially in compliance with all environmental requirements.

Various state and federal laws regulate our handling, storage and disposal of waste materials. The EPA and the MDEQ have aggressive programs to manage the clean up of contaminated property. We have extensive land holdings and, from time to time, must investigate claims of improperly disposed contaminants. We anticipate our utility and non-utility companies may periodically be included in various types of environmental proceedings.

## DTE2

In 2003, we began the development of DTE2, an enterprise resource planning (ERP) system initiative to improve existing processes and to implement new core information systems, relating to finance, human resources, supply chain and work management. As part of this initiative, we are implementing Enterprise Business Systems software including, among others, products developed by SAP AG and MRO Software, Inc. The first phase of implementation occurred in 2005 in the regulated electric fossil generation unit. Full implementation throughout the Company is not anticipated until 2007.

The conversion of data and the implementation and operation of the ERP will be continuously monitored and reviewed and should ultimately strengthen our internal control structure and lead to increased cost efficiencies. 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.

We have spent approximately \$210 million through the end of 2005 and expect total spending over the life of the project to be between \$375 million and \$400 million. We expect the benefits of lower costs, faster business cycles, repeatable and optimized processes, enhanced internal controls, improvements in inventory management and reductions in system support costs to outweigh the expense of our investment in this initiative.

## Midwest Independent System Operator (MISO)

The MISO was formed in 1996 by its member transmission owners and in December 2001 received FERC approval as a Regional Transmission Organization (RTO) authorized to provide regional transmission services as prescribed by FERC in its Order 2000. Order 2000 requires an RTO to perform eight functions, including tariff administration, transmission system congestion management, provision of ancillary services to support transmission operations, market monitoring, interregional coordination and the coordination of system planning and expansion. MISO's independence from ownership of either generation or transmission facilities is intended to enable it to ensure fair access to the transmission grid, and through its congestion management role, MISO is also charged with ensuring grid reliability. MISO's initial provision of transmission services in December 2001 was known as Day 1 operations.

In keeping with Order 2000, which permits RTOs to provide real-time energy imbalance services and a market-based mechanism for congestion management, MISO, on April 1, 2005, launched its Midwest Energy Market, or Day 2 operations, and began regional wholesale electric market operations and transmission service throughout its area. A key feature of the Midwest Energy Market is the establishment of Locational Marginal Prices (LMPs) which provide price transparency for the sale and purchase of wholesale electricity at different locations in the market territory. The LMP is the market clearing price at a specific pricing location in the Midwest Energy Market that is equal to the cost of supplying the next increment of load at that location. The value of an LMP is the same whether a purchase or sale is made at that location. Detroit Edison participates in the Midwest Energy Market by offering its generation on a day-ahead and real time basis and by bidding for power in the market to serve its load. The cost of power procured from the market net of any gain realized from generation sold into the market is included and recovered through the PSCR mechanism. In addition, LMPs are expected to encourage new generation to locate where the power produced is of most value to the load and is expected to identify where new transmission facilities are needed to relieve grid congestion.

MISO is compensated for assuring grid reliability and for supporting the energy market through FERC-approved rates charged to load.

Detroit Edison became a non-transmission owning member of MISO in compliance with section 10w (1) of PA 141. The MPSC has ordered that MISO costs charged to Detroit Edison should be recovered through the PSCR mechanism.

## Federal Energy Policy Act of 2005

In August 2005, the Energy Policy Act of 2005 (Energy Act) was signed into law. Among other provisions, the Energy Act:

- establishes mandatory electric reliability standards;
- repeals the Public Utility Holding Company Act of 1935;
- renews the Price Anderson Act for twenty years which provides liability protection for nuclear power plants;
- increases funding levels for the Low-Income Home Energy Assistance Program; and
- increases FERC oversight responsibilities for the electric utility industry.

The implementation of the Energy Act requires proceedings at the state level and development of regulations by the FERC, as well as other federal agencies. The impact of the Energy Act on our results of operations will depend on the implementation of final rules and cannot be fully determined at this time.

## New Accounting Pronouncements

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

## Fair Value of Contracts

The following disclosures are voluntary and provide enhanced transparency of the derivative activities and position of our trading businesses 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 activities", 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 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, gas and oil 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 thereby not impacting 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.
- “Other Non-Trading Activities” primarily represent derivative activity associated with our Michigan gas reserves and synfuel operations. A substantial portion of the price risk associated with the gas reserves has been mitigated through 2013. Changes in the value of the hedges are recorded as “assets or liabilities from risk management and trading activities”, with an offset in other comprehensive income to the extent that the hedges are deemed effective. Oil-related derivative contracts have been executed to economically hedge cash flow risks related to underlying, non-derivative synfuel related positions through 2007. The amounts shown in the following tables exclude the value of the underlying gas reserves and synfuel proceeds including changes therein.

## Roll-Forward of Mark to Market Energy Contract Net Assets

The following tables provide details on changes in our mark to market net asset or (liability) position during 2005:

<i>(in Millions)</i>	Trading Activities			Total	Other Non-Trading Activities	
	Proprietary Trading	Structured Contracts	Economic Hedges		Total	Total
MTM at December 31, 2004	\$ 3	\$ 23	\$ (98)	\$ (72)	\$ (100)	\$ (172)
Reclassified to realized upon settlement	(2)	(16)	32	14	66	80
Changes in fair value recorded to income	6	(91)	(58)	(143)	43	(100)
Amortization of option premiums	-	-	(3)	(3)	(26)	(29)
Amounts recorded to unrealized income	4	(107)	(29)	(132)	83	(49)
Amounts recorded in OCI (Note 1)	-	(54)	17	(37)	(187)	(224)
Option premiums paid and other	(115)	2	-	(113)	64	(49)
MTM at December 31, 2005	\$ (108)	\$ (136)	\$ (110)	\$ (354)	\$ (140)	\$ (494)

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, 2005. Amounts that relate to contracts that become due within twelve months are classified as current and all remaining amounts are classified as noncurrent.

<i>(in Millions)</i>	Trading Activities				Totals	Other Non-Trading Activities	
	Proprietary Trading	Structured Contracts	Economic Hedges	Eliminations		Total Assets (Liabilities)	Total Assets (Liabilities)
Current assets	\$ 295	\$ 161	\$ 205	\$ (3)	\$ 658	\$ 148	\$ 806
Noncurrent assets	9	53	186	(6)	242	74	316
Total MTM assets	304	214	391	(9)	900	222	1,122
Current liabilities	(359)	(232)	(301)	3	(889)	(200)	(1,089)
Noncurrent liabilities	(53)	(118)	(200)	6	(365)	(162)	(527)
Total MTM liabilities	(412)	(350)	(501)	9	(1,254)	(362)	(1,616)
Total MTM net assets (liabilities)	\$ (108)	\$ (136)	\$ (110)	\$ -	\$ (354)	\$ (140)	\$ (494)

## Maturity of Fair Value of MTM Energy Contract Net Assets

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 positions for which broker quotes are available. Although the NYMEX has currently quoted prices for the next 72 months, 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.

As a result of adherence to generally accepted accounting principles, the tables above do not include the expected favorable earnings impacts of certain non-derivative gas storage and power contracts. We entered into economically favorable transactions in early 2005 to delay previously planned withdrawals from gas storage due to a decrease in the current price for natural gas and an increase in the forward price for natural gas. We anticipate the financial impact of this timing difference will reverse when the gas is withdrawn from storage in the current storage cycle and is sold at prices significantly in excess of the cost of gas in storage. In addition, we entered into forward power contracts to economically hedge certain physical and capacity power contracts. We expect the timing difference on the forward power contracts will be fully realized by the end of 2007.

The table below shows the maturity of our MTM positions:

<i>(in Millions)</i>				<b>Total Fair Value</b>
<b>Source of Fair Value</b>	<b>2006</b>	<b>2007</b>	<b>2008</b>	
Proprietary Trading	\$ (64)	\$ (44)	\$ -	\$ (108)
Structured Contracts	(71)	(61)	(4)	(136)
Economic Hedges	(96)	(4)	(10)	(110)
Total Trading Activities	(231)	(109)	(14)	(354)
Other Non-Trading Activities	(52)	(63)	(25)	(140)
<b>Total</b>	<b>\$ (283)</b>	<b>\$ (172)</b>	<b>\$ (39)</b>	<b>\$ (494)</b>

## 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 purchases of coal, uranium, and 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. See Note 1.

Our Coal-Based Fuels and Landfill Gas Recovery businesses are also subject to crude oil price risk. As previously discussed, production tax credits generated by DTE Energy's synfuel, coke battery and

landfill gas recovery operations are subject to phase-out if domestic crude oil prices reach certain levels. We have entered into a series of derivative contracts for 2006 through 2007 to economically hedge the impact of oil prices on a portion of our synfuel cash flow.

See Note 12.

### 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. Certain of our customers have filed for bankruptcy protection under Chapter 11 of the U. S. Bankruptcy Code. We regularly review contingent matters relating to these customers and our purchase and sale contracts and we record provisions for amounts considered at risk of probable loss. We believe our previously accrued amounts are adequate for probable loss. The final resolution of these matters is not expected to have a material effect on our financial statements.

#### Other

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.

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, 2005:

<i>(in Millions)</i>			
	<b>Credit Exposure before Collateral</b>	<b>Cash Collateral</b>	<b>Net Credit Exposure</b>
<b>Investment Grade (1)</b>			
A- and Greater	\$ 444	\$ (46)	\$ 398
BBB+ and BBB	290	(9)	281
BBB-	17	-	17
<b>Total Investment Grade</b>	<b>751</b>	<b>(55)</b>	<b>696</b>
<b>Non-investment grade (2)</b>	<b>52</b>	<b>(13)</b>	<b>39</b>
<b>Internally Rated - investment grade (3)</b>	<b>129</b>	<b>(9)</b>	<b>120</b>
<b>Internally Rated - non-investment grade (4)</b>	<b>11</b>	<b>-</b>	<b>11</b>
<b>Total</b>	<b>\$ 943</b>	<b>\$ (77)</b>	<b>\$ 866</b>

(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 29% 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 5% 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 7% 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, 2005, the Company has a floating rate debt to total debt ratio of approximately 15% (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. Additionally, we may enter into fair value currency hedges to mitigate changes in the value of contracts or loans.

## 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, 2005 by a hypothetical 10% and calculating the resulting change in the fair values. The results of the sensitivity analysis calculations follow:

<i>(in Millions)</i>			
<b>Activity</b>	<b>Assuming a 10% increase in rates</b>	<b>Assuming a 10% decrease in rates</b>	<b>Change in the fair value of</b>
Gas Contracts	\$ (9)	\$ 7	Commodity contracts and options
Power Contracts	\$ (20)	\$ 21	Commodity contracts
Oil Contracts	\$ 39	\$ (40)	Commodity options
Interest Rate Risk	\$ (296)	\$ 318	Long-term debt
Foreign Currency Risk	\$ 3	\$ (3)	Forward contracts