

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

OVERVIEW

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

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

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

Electric Customer Choice Program – Since 2002, Michigan residents and businesses have had the option of participating in the electric Customer Choice program. This program is designed to give all customers added choices and the opportunity to benefit from lower power costs resulting from competition. However, Detroit Edison's rates are regulated by the Michigan Public Service Commission (MPSC), while alternative suppliers can charge market-based rates. This regulation has hindered Detroit Edison's ability to retain customers. In addition, the MPSC has maintained regulated rates for certain groups of customers that exceed the cost of service to those customers. This has resulted in high levels of participation in the electric Customer Choice program by those customers that have the highest rates relative to their cost of service, primarily commercial and industrial businesses. As a result, our margins continue to be affected. To address this issue, we filed a revenue neutral rate

restructuring proposal in February 2005 designed to adjust rates for each customer class to be reflective of the full costs incurred to service such customers. Under the proposal, Detroit Edison's commercial and industrial rates would be lowered in 2006, but residential rates would increase over a five-year period beginning in 2007. The number and mix of customers participating in the electric Customer Choice program could be impacted under the rate restructuring.

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

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

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

In 2004, the MPSC issued interim and final rate orders that authorized electric rate increases totaling \$374 million, and eliminated transition credits and implemented transition

MD&A

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

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

Effect of Interim and Final Rate Orders

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

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

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

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

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

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

the MPSC in February 2005 seeking authority to implement a tracking mechanism for retiree health care costs.

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

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

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

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

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

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

Operating expenses associated with synfuel projects exceed operating revenues and therefore generate operating losses, which have been more than offset by the resulting Section 29 tax credits. In order to recognize Section 29 tax credits, a taxpayer must have sufficient taxable income in the year the tax credit is generated. Once earned, the tax credits are utilized subject to

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

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

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

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

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

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

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

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

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

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

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

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

RESULTS OF OPERATIONS

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

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

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

ENERGY RESOURCES

Utility – Power Generation

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

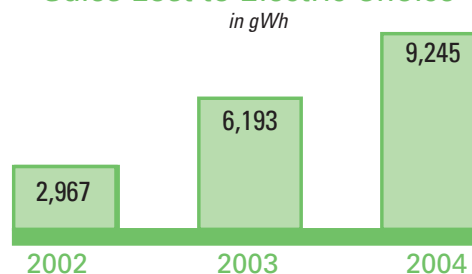
Factors impacting income: Power Generation earnings decreased \$173 million in 2004 and \$6 million in 2003, compared to the prior year. As subsequently discussed, these results primarily reflect reduced gross margins and increased operation and maintenance expenses.

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

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

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

Sales Lost to Electric Choice



Operating revenues and fuel and purchased power costs decreased in 2004 and 2003 reflecting a \$1.27 per megawatt hour (MWh) (8%) decline in fuel and purchased power costs during 2004 and a \$.64 per MWh (4%) decline during 2003. Fuel and purchased power costs are a pass-through with the reinstatement of the PSCR in 2004, and therefore do not affect margins or earnings associated with uncapped customers. The decrease in fuel and purchased power costs is attributable to lower priced purchases and the use of a more favorable power supply mix driven by higher generation output. The favorable mix is due to lower purchases, driven by lost sales under the electric Customer Choice program. The comparison was also affected by higher costs associated with

substitute power purchased to meet customer demand during the August 2003 blackout. We were required to purchase additional power during the 36-day period it took for our generation fleet to return to pre-blackout capacity.

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

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

(1) Represents fuel costs associated with power plants.

(2) Includes amounts associated with hedging activities.

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

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

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

and interest income includes the accrual of carrying charges on environmental-related regulatory assets.

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

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

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

Energy Services

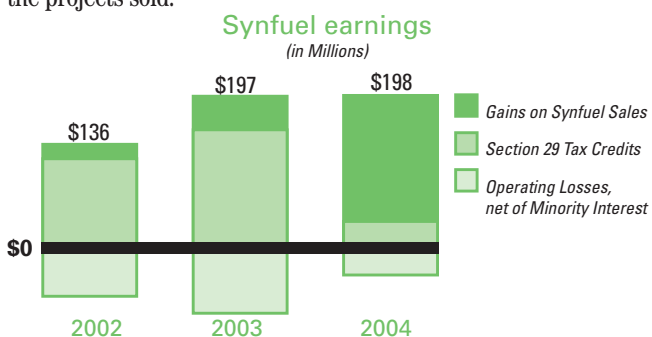
Energy Services is comprised of Coal-Based Fuels, On-Site Energy Projects and non-utility Power Generation. Coal-Based Fuels operations include producing synthetic fuel from nine synfuel plants and producing coke from three coke battery plants. The production of synthetic fuel from all of our synfuel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

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

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

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

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



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

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

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

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

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

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

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

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

Energy Marketing & Trading

Energy Marketing & Trading consists of the electric and gas marketing and trading operations of DTE Energy Trading and CoEnergy. DTE Energy Trading focuses on physical power marketing and structured transactions, as well as the enhancement of returns from DTE Energy's power plants. CoEnergy focuses on physical gas marketing and the optimization of DTE Energy's owned and contracted natural gas pipelines and gas storage capacity. To this end, both companies enter into derivative financial instruments as part of their marketing and hedging strategies, including forwards, futures, swaps and option contracts. Most of the

derivative financial instruments are accounted for under the mark to market method, which results in earnings recognition of unrealized gains and losses from changes in the fair value of the derivatives.

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

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

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

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

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

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

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

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

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

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

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

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

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

Outlook – Energy Marketing & Trading will seek to manage its business in a manner consistent with, and complementary to, the growth of our other business segments. Gas storage and transportation capacity enhances our ability to provide reliable and custom-tailored bundled services to large-volume end users and utilities. This capacity, coupled with the synergies from DTE Energy's other businesses, positions the segment to add value. Significant portions of the Energy Marketing & Trading portfolio are economically hedged. The portfolio includes financial instruments and gas inventory, as well as owned and contracted natural gas pipelines and storage assets. The financial instruments are deemed derivatives, whereas the gas inventory, pipelines and storage assets are not considered derivatives for accounting purposes. As a result, Energy Marketing & Trading will experience earnings volatility as derivatives are marked to market without revaluing the underlying non-derivative contracts and assets. The majority of such earnings volatility is associated with the natural gas storage cycle, which runs annually from April of one year to March of the next year. Our strategy is to economically hedge the price risk of all gas purchases for storage with sales in the over-the-counter (forwards) and futures markets. Current accounting rules require the marking to market of forward sales and futures, but do not allow for the marking to market of the related gas inventory. This results in gains and losses that are recognized in different interim and annual accounting periods. We anticipate the financial impact of this timing difference will reverse by the end of each storage cycle. See "Fair Value of Contracts" section that follows.

Non-utility – Other

Our other non-utility businesses include our Coal Services and Biomass units. Coal Services provides fuel, transportation and rail equipment management services. We specialize in minimizing fuel costs and maximizing reliability of supply for energy-intensive customers. Additionally, we participate in coal trading and

coal-to-power tolling transactions, as well as the purchase and sale of emissions credits. Coal Services has formed a subsidiary, DTE PepTec Inc., which uses proprietary technology to produce high quality coal products from fine coal slurries typically discarded from coal mining operations. Biomass develops, owns and operates landfill recovery systems in the U.S. Gas produced from many of these landfill sites qualifies for Section 29 tax credits.

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

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

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

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

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

ENERGY DISTRIBUTION

Utility - Power Distribution

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

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

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

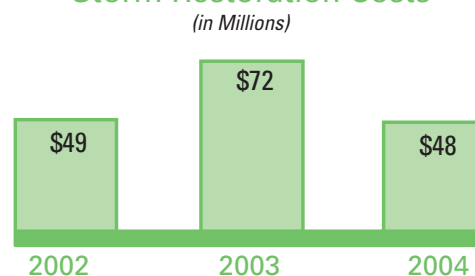
(in Thousands of MWh)	2004	2003	2002
Electric Deliveries			
Residential	15,081	15,074	15,958
Commercial	13,425	15,942	18,395
Industrial	11,472	12,254	13,590
Wholesale	2,197	2,241	2,249
Other	401	402	403
	42,576	45,913	50,595
Electric Choice	9,245	6,193	2,967
Electric Choice – Self Generations*	595	1,088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

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

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

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

Storm Restoration Costs



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

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

Non-Utility

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

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

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

ENERGY GAS

Utility – Gas Distribution

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

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

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

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

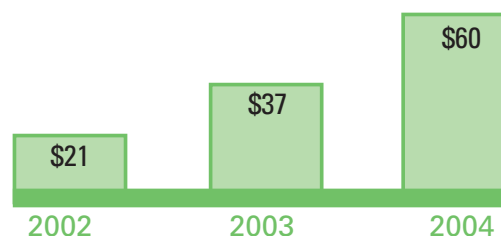
(in Millions)	2004	2003	2002
Gas Markets			
Gas sales	\$ 1,435	\$ 1,242	\$ 1,135
End user transportation	119	136	122
	1,554	1,378	1,257
Intermediate transportation	56	51	48
Other	72	69	64
	\$ 1,682	\$ 1,498	\$ 1,369

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

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

Uncollectible Accounts Expense

(in Millions)



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

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

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

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

Non-utility

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

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

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

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

CORPORATE & OTHER

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

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

DISCONTINUED OPERATIONS

Southern Missouri Gas Company (SMGC) – We own SMGC, a public utility engaged in the distribution, transmission and sale of natural gas in southern Missouri. In 2004, management approved

the marketing of SMGC for sale. Under U.S. generally accepted accounting principles, we classified SMGC as a discontinued operation in 2004 and recognized a net of tax impairment loss of approximately \$7 million, representing the write-down to fair value of the assets of SMGC, less costs to sell, and the write-off of allocated goodwill. In November 2004, we entered into a definitive agreement providing for the sale of SMGC. Following receipt of regulatory approvals and resolution of other contingencies, it is anticipated that the transaction will close in 2005.

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

See Note 3 for further discussion.

CUMULATIVE EFFECT OF ACCOUNTING CHANGES

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

CAPITAL RESOURCES AND LIQUIDITY

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

Cash Requirements

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

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

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

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

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

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

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

Cash from Operating Activities

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

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

Although DTE Energy's overall earnings were \$431 million in 2004, cash from operations totaling \$995 million was up \$45 million from the comparable 2003 period. The operating cash flow comparison

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

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

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

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

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

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

Cash flows from our synfuel business are expected to total approximately \$1.6 billion between 2005 and 2008. The redeployment of this cash represents a unique opportunity to increase shareholder value and strengthen our balance sheet. We expect to use this cash to reduce debt, to continue to pursue growth investments that meet

our strict risk-return and value creation criteria and to potentially repurchase common stock if adequate investment opportunities are not available. Our objectives for cash redeployment are to strengthen the balance sheet and coverage ratios in order to improve our current credit ratings and outlook, and to more than replace the value of synfuels.

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

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

Cash from Investing Activities

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

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

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

Cash from Financing Activities

We rely on both short-term borrowings and longer-term financings as a source of funding for our capital requirements not satisfied by the Company's operations. Short-term borrowings, which are

mostly in the form of commercial paper borrowings, provide us with the liquidity needed on a daily basis. Our commercial paper program is supported by our unsecured credit facilities.

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

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

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

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

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

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

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

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

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

Contractual Obligations

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

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

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

Credit Ratings

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

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

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

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

* Currently on negative outlook

CRITICAL ACCOUNTING ESTIMATES

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

Regulation

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

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

* Excludes securitized regulatory assets

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

Risk Management and Trading Activities

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

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

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

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

Section 29 Tax Credits

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

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

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

Goodwill

Certain of our business units have goodwill resulting from purchase business combinations (Notes 2 and 16). In accordance with SFAS No. 142, *“Goodwill and Other Intangible Assets,”* each of our

reporting units with goodwill is required to perform impairment tests annually or whenever events or circumstances indicate that the value of goodwill may be impaired. In order to perform these impairment tests, we must determine the reporting unit's fair value using valuation techniques, which use estimates of discounted future cash flows to be generated by the reporting unit. These cash flow valuations involve a number of estimates that require broad assumptions and significant judgment by management regarding future performance. To the extent estimated cash flows are revised downward, the reporting unit may be required to write down all or a portion of its goodwill, which would adversely impact our earnings.

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

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

Pension and Postretirement Costs

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

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

We base our determination of the expected return on qualified plan assets on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation recognizes changes in fair value in a systematic manner over a three-year

period. Because of this method, the future value of assets will be impacted as previously deferred gains or losses are recorded. We have unrecognized net gains due to the recent favorable performance of the financial markets. As of December 31, 2004, we had \$63 million of cumulative gains that remain to be recognized in the calculation of the market-related value of assets.

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

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

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

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

pension plans in 2005. At the discretion of management, we anticipate making a \$0 to \$40 million contribution to our postretirement plans in 2005.

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

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

Allowance for Doubtful Accounts

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

Legal and Tax Reserves

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

ENVIRONMENTAL MATTERS

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

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

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

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

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

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

DTE ENERGY OPERATING SYSTEM AND DTE2

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

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

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

NEW ACCOUNTING PRONOUNCEMENTS

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

FAIR VALUE OF CONTRACTS

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

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

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

Contracts we typically classify as derivative instruments are power and gas forwards, futures, options and swaps, as well as foreign currency contracts. Items we do not generally account for as

derivatives (and which are therefore excluded from the following tables) include gas inventory, gas storage and transportation arrangements, full-requirements power contracts and gas and oil reserves. As subsequently discussed, we have fully reserved the value of derivative contracts beyond the liquid trading timeframe and which therefore do not impact income.

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

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

roll forward of mark to market energy contract net assets

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

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

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

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

Maturity of Fair Value of MTM Energy Contract Net Assets

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

The table below shows the maturity of our MTM positions:

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

Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

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

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

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

Credit Risk

Bankruptcies

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

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

Energy Trading & CoEnergy Portfolio

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

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

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

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

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

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

Interest Rate Risk

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

Foreign Currency Risk

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

Summary of Sensitivity Analysis

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

The results of the sensitivity analysis calculations follow:

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

report of management's responsibility

for financial statements and internal control over financial reporting

reports

Financial Statements

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

Internal Control Over Financial Reporting

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

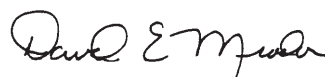
All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Projections of any evaluation of the effectiveness to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

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

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



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



David E. Meador
Executive Vice President and Chief Financial Officer