

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

### Overview

DTE Energy is a diversified energy company with 2007 operating revenues in excess of \$8 billion and approximately \$24 billion in assets. We are the parent company of The Detroit Edison Company (Detroit Edison) and Michigan Consolidated Gas Company (MichCon), regulated electric and gas utilities engaged primarily in the business of providing electricity and natural gas sales, distribution and storage services throughout southeastern Michigan. We operate four energy-related non-utility segments with operations throughout the United States.

The following table summarizes our financial results:

<i>(in Millions, except Earnings per Share)</i>	2007	2006	2005
Income from Continuing Operations	\$ 787	\$ 389	\$ 272
Earnings per Diluted Share	\$ 4.62	\$ 2.18	\$ 1.55
Net Income	\$ 971	\$ 433	\$ 537
Earnings per Diluted Share	\$ 5.70	\$ 2.43	\$ 3.05

The increase for 2007 was primarily due to approximately \$370 million in net income resulting from the gain on the sale of the Antrim shale gas exploration and production business of \$900 million (\$580 million after-tax), partially offset by losses recognized on related hedges of \$323 million (\$210 million after-tax), including recognition of amounts previously recorded in accumulated other comprehensive income. Net income in 2006 was adversely impacted by the temporary idling of synfuel plants along with associated impairments and reserves, and higher levels of deferrals of potential gains from selling interests in the synfuel plants. Impairments within our Power and Industrial Projects segment also had a negative impact on the results of the 2006 period. The 2006 decrease was partially offset by higher earnings at Detroit Edison, and Energy Trading segment mark-to-market losses in 2005 that did not recur in 2006.

The items discussed below influenced our current financial performance and/or may affect future results:

- Effects of weather and collectibility of accounts receivable on utility operations;
- Impact of regulatory decisions on our utility operations;
- Monetization of our Unconventional Gas Production business;
- Monetization of our Power and Industrial Projects business;
- Results in our Energy Trading business;
- Synfuel-related earnings; and
- Cost reduction efforts and required environmental and reliability-related capital investments.

### Utility Operations

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

Our Gas Utility segment consists of MichCon and Citizens Gas Fuel Company (Citizens). MichCon is engaged in the purchase, storage, transmission, distribution and sale of natural gas to approximately 1.3 million residential, commercial and industrial customers throughout Michigan. MichCon also has subsidiaries involved in the gathering and transmission of natural gas in northern Michigan. Citizens distributes natural gas in Adrian, Michigan to approximately 17,000 customers.

**Weather** – Earnings from our utility operations are seasonal and very sensitive to weather. Electric utility earnings are primarily dependent on hot summer weather, while the gas utility's results are primarily dependent on cold winter weather. Restoration and other costs associated with storm-related power outages lowered pre-tax earnings by \$68 million in 2007, \$46 million in 2006 and \$82 million in 2005.

**Receivables** – Both utilities continue to experience high levels of past due receivables, especially within our Gas Utility operations, which is primarily attributable to economic conditions and a lack of adequate levels of governmental assistance for low-income customers.

We have taken aggressive actions to reduce the level of past due receivables, including increasing 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 2006, we sold previously written-off accounts of \$43 million resulting in a gain and net proceeds of \$1.9 million. The gain was recorded as a recovery through doubtful accounts expense, which is included within Operation and maintenance expense.

Our doubtful accounts expense for the two utilities increased to \$135 million in 2007 from \$123 million in 2006 and from \$98 million in 2005.

The April 2005 Michigan Public Service Commission (MPSC) gas rate order provided for an uncollectible true-up mechanism for MichCon. The uncollectible true-up mechanism enables MichCon to recover ninety percent of the difference between the actual uncollectible expense for each year and \$37 million after an annual reconciliation proceeding before the MPSC. The MPSC approved the 2005 annual reconciliation in December 2006, allowing MichCon to surcharge \$11 million beginning in January 2007. The MPSC approved the

2006 annual reconciliation in December 2007, allowing MichCon to surcharge \$33 million beginning in January 2008. We expect to file the 2007 reconciliation in the first quarter of 2008 requesting an additional surcharge of approximately \$33 million including the uncollected balance from 2005 surcharge. We accrue interest income on the outstanding balances.

**Regulatory activity** – Detroit Edison filed a general rate case on April 13, 2007 based on a 2006 historical test year. The filing with the MPSC requested a \$123 million, or 2.9 percent, average increase in Detroit Edison's annual revenue requirement for 2008. On August 31, 2007, Detroit Edison filed a supplement to its April 2007 rate case filing to account for certain recent events. A July 2007 decision by the Court of Appeals of the State of Michigan remanded back to the MPSC the November 2004 order in a prior Detroit Edison rate case that denied recovery of merger control premium costs. Also, the Michigan legislature enacted the Michigan Business Tax (MBT) in July 2007. The supplemental filing addressed the recovery of the merger control premium costs and the enactment of the MBT. The net impact of the supplemental changes results in an additional revenue requirement of approximately \$76 million. On February 20, 2008, Detroit Edison filed an update to its April 2007 rate case filing. The update reflects the use of 2009 as the projected test year and includes a revised 2009 load forecast, and 2009 estimates on environmental and advanced metering infrastructure capital expenditures, and adjustments to the calculation of the MBT. See Note 5 of the Notes to Consolidated Financial Statements.

The MPSC issued an order on August 31, 2006 approving a settlement agreement providing for an annualized rate reduction of \$53 million for 2006 for Detroit Edison, effective September 5, 2006. Beginning January 1, 2007, and continuing until April 13, 2008, one year from the filing of the general rate case on April 13, 2007, rates were reduced by an additional \$26 million, for a total reduction of \$79 million annually. Detroit Edison experienced a rate reduction of approximately \$76 million in 2007, as a result of this order. The revenue reduction is net of the recovery of costs associated with the Performance Excellence Process. The settlement agreement provides for some level of realignment of the existing rate structure by allocating a larger percentage of the rate reduction to the commercial and industrial customer classes than to the residential customer classes.

In August 2006, MichCon filed an application with the MPSC requesting permission to sell base gas that would become accessible with storage facilities upgrades. In December 2006, MichCon filed its 2007-2008 Gas Cost Recovery (GCR) plan case proposing a maximum GCR factor of \$8.49 per thousand cubic feet (Mcf) of gas. In August 2007, a settlement agreement in this proceeding was approved by the MPSC that provides for a sharing with customers of the proceeds from the sale of base gas. In addition, the agreement provides for a rate case filing moratorium until January 1, 2009, unless certain unanticipated changes occur that impact income by more than \$5 million. MichCon's gas storage enhancement projects, the main subject of the aforementioned settlement, will enable 17 billion cubic feet (Bcf) of gas to become available for cycling. Under the settlement terms, MichCon delivered 13.4 Bcf of this gas to its customers through 2007 at a savings to market-priced supplies of approximately \$54 million. This settlement provides for MichCon to retain the proceeds from the sale of 3.6 Bcf of gas, which MichCon expects to sell in 2007, 2008 and 2009. In the fourth quarter of 2007, MichCon sold .75 Bcf of base gas and recognized a pre-tax gain of \$5 million. By enabling MichCon to retain the profit from the sale of this gas, the settlement provides MichCon with the opportunity to earn an 11% return on equity with no customer rate increase for a period of five years from 2005 to 2010.

**Coal Supply** – Our generating fleet produces approximately 79% of its electricity from coal. Increasing coal demand from domestic and international markets has resulted in significant price increases. In addition, difficulty in recruiting workers, obtaining environmental permits and finding economically recoverable amounts of new coal has resulted in decreasing coal output from the central Appalachian region. Furthermore, as a result of environmental regulation and declining eastern coal stocks, demand for cleaner burning western coal has increased. This increased demand for western coal has also resulted in a corresponding demand for western rail shipping, straining railroad capacity and resulting in longer lead times for western coal shipments.

**Nuclear Fuel** – We operate one nuclear facility that undergoes a periodic refueling outage approximately every eighteen months. Uranium prices have been rising due to supply concerns. In the future, there may be additional nuclear facilities constructed in the industry that may place additional pressure on uranium supplies and prices. We have a contract with the U.S. Department of Energy (DOE) for the future storage and disposal of spent nuclear fuel from Fermi 2. We are obligated to pay the DOE a fee of 1 mill per kWh of Fermi 2 electricity generated and sold. The fee is a component of nuclear fuel expense. Delays have occurred in the DOE's program for the acceptance and disposal of spent nuclear fuel at a permanent repository. Until the DOE is able to fulfill its obligation under the contract, we are responsible for the spent nuclear fuel storage. We have begun work on an on-site dry cask storage facility. We are a party in the litigation against the DOE for both past and future costs associated with the DOE's failure to accept spent nuclear fuel under the timetable set forth in the Federal Nuclear Waste Policy Act of 1982.

## Non-Utility Operations

We have made significant investments in non-utility asset-intensive businesses. We employ disciplined investment criteria when assessing opportunities that leverage our assets, skills and expertise. Specifically, we invest in targeted energy markets with attractive competitive dynamics where meaningful scale is in alignment with our risk profile. A number of factors have impacted our non-utility businesses, including the effect of oil prices on the synthetic fuel business, losses and impairments from certain power generation assets, waste coal recovery and landfill gas recovery businesses, and earnings volatility in our energy trading business. As part of a strategic review of our non-utility operations, we have taken and continue to pursue various actions including the sale, restructuring or recapitalization of certain non-utility businesses that generated approximately \$900 million in after-tax cash proceeds in 2007 and is expected to generate an additional \$800 million in 2008. See Note 3 of the Notes to Consolidated Financial Statements for information on the sale of our Antrim shale gas exploration and production business in northern Michigan, the sale of a portion of our Barnett shale properties and the pending financing and sale of a 50 percent ownership interest in select projects within the Power and Industrial Projects segment.

### Coal and Gas Midstream

Our Coal and Gas Midstream segment consists of Coal Transportation and Marketing and the Pipelines, Processing and Storage businesses.

Coal Transportation and Marketing provides fuel, transportation, storage, blending, 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 marketing and coal-to-power tolling transactions, as well as the purchase and sale of emissions credits. We perform coal mine methane extraction, in which we recover methane gas from mine voids for processing and delivery to natural gas pipelines, industrial users, or for small power generation projects. In 2008, we expect to see a decrease in net income since approximately \$11 million of our 2007 Coal Transportation and Marketing net income was dependent upon our Synfuel operations that ceased operations at the end of 2007. We plan to continue to build our capacity to transport greater amounts of western coal, and have expanded our coal storage and blending capacity with the start of commercial operation of our coal terminal in Chicago in April 2007.

Pipelines, Processing and Storage owns a partnership interest in two interstate transmission pipelines, four carbon dioxide processing facilities and two natural gas storage fields. The pipeline and storage assets are primarily supported by stable, long-term, fixed-price revenue contracts. The assets of these businesses are well integrated with other DTE Energy operations. Pursuant to an operating agreement, MichCon provides physical operations, maintenance and technical support for the Washington 28 and Washington 10 storage facilities.

Pipelines, Processing and Storage is continuing its steady growth plan of expansion of storage capacity, with two new expansions and the expanding and building of new pipeline capacity to serve markets in the Midwest and Northeast United States.

## Unconventional Gas Production

Our Unconventional Gas Production business is engaged in natural gas exploration, development and production primarily within the Barnett shale in north Texas.

In 2007, we sold our Antrim shale gas exploration and production business in the northern lower peninsula of Michigan to Atlas Energy Resources LLC for gross proceeds of \$1.262 billion. See Note 3 of the Notes to Consolidated Financial Statements.

In 2007, we continued to develop our position in the Barnett shale basin in north Texas, where our total leasehold acreage (after the January 2008 sale referred to below) is 63,541, net of impairments (58,742 acres, net of interest of others). We continue to acquire select acreage positions in active development areas in the Barnett shale to optimize our existing portfolio.

Our Unconventional Gas Production segment recorded pre-tax impairment losses of \$27 million in 2007, related to the write-off of unproved properties and expiration of leases in Bosque County, which is located in the southern expansion area of the Barnett shale basin in north Texas. The properties were impaired due to the lack of economic and operating viability of the southern expansion area. See Note 4 of the Notes to Consolidated Financial Statements.

As a component of our risk management strategy for our Barnett shale reserves, we hedged a portion of anticipated production from our reserves to secure an attractive investment return. As of December 31, 2007, we have a series of cash flow hedges for approximately 5.5 Bcf of anticipated Barnett gas production through 2010 at an average price of \$7.48 per Mcf.

In August 2007, we announced that we were exploring opportunities to monetize a portion of our interests in the Barnett shale. On January 15, 2008, we sold a portion of our Barnett shale properties for gross proceeds of approximately \$250 million, subject to post-closing adjustments. The Company will recognize a gain on the sale in the first quarter of 2008. The properties in the sale include 186 Bcf of proved and probable reserves on approximately 11,000 net acres in the core area of the Barnett shale.

We plan to retain our holdings in the western portion of the Barnett shale and anticipate significant opportunities to develop our current position while accumulating additional acreage in and around our existing assets.

Current natural gas prices and successes within the Barnett shale are resulting in additional capital being invested into the area. The competition for opportunities and goods and services may result in increased operating costs. However, our experienced Barnett shale personnel provide an advantage in addressing potential cost increases.

	2007	2006	2005
<b>Texas – Barnett Shale</b>			
<b>Net Producing Wells</b>			
Held for sale	33	27	8
Continuing operations	120	83	47
<b>Total</b>	<b>153</b>	<b>110</b>	<b>55</b>
<b>Production Volume (Bcfe)</b>			
Held for sale	4.7	2.8	0.4
Continuing operations	3.0	1.3	0.4
<b>Total</b>	<b>7.7</b>	<b>4.1</b>	<b>0.8</b>
<b>Proved Reserves (Bcfe) (1)</b>			
Held for sale	75	60	11
Continuing operations	144	111	48
<b>Total</b>	<b>219</b>	<b>171</b>	<b>59</b>
<b>Net Developed Acreage (1)</b>			
Held for sale	4,987	3,977	1,349
Continuing operations (2)	9,880	10,693	13,018
<b>Total</b>	<b>14,867</b>	<b>14,670</b>	<b>14,367</b>
<b>Net Undeveloped Acreage (1)</b>			
Held for sale	5,809	6,164	7,801
Continuing operations (2)	38,066	27,613	13,495
<b>Total</b>	<b>43,875</b>	<b>33,777</b>	<b>21,296</b>
<b>Capital Expenditures (in Millions) (3)</b>			
Held for sale	\$ 45	\$ 67	\$ 19
Continuing operations	95	61	76
<b>Total</b>	<b>\$ 140</b>	<b>\$ 128</b>	<b>\$ 95</b>
<b>Future Undiscounted Net Cash Flows (in Millions) (4)</b>			
Held for sale	\$ 282	\$ 167	\$ 63
Continuing operations	521	305	266
<b>Total</b>	<b>\$ 803</b>	<b>\$ 472</b>	<b>\$ 329</b>
<b>Average gas price (per Mcf)</b>	<b>\$ 6.29</b>	<b>\$ 5.66</b>	<b>\$ 9.01</b>

(1) Due to the impairment of acreage and wells in the southern expansion area of the Barnett shale during 2007, the proved reserves and acreage numbers above do not include the southern area. Total net acreage related to impaired leases in the southern expansion area was 23,659 acres, 32,083 acres and 40,332 acres for the years 2007, 2006 and 2005, respectively.

(2) Developed acreage for continuing operations shows a decrease from prior periods, which reflects the Company's experience that spacing of wells in the Barnett shale has been reduced over the years. This reduced spacing estimate drives a shift from developed to undeveloped acreage counts. We continue to expand our total position in the western expansion area of the Barnett shale. During 2007, total net acreage for continuing operations increased by 9,640 acres.

(3) Excludes sold and impaired assets in southern expansion area of the Barnett shale.

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

## Power and Industrial Projects

Power and Industrial Projects is comprised primarily of projects that deliver energy and utility-type products and services to industrial, commercial and institutional customers, and biomass energy projects. This segment provides utility-type services using project assets usually located on or near the customers' premises in the steel, automotive, pulp and paper, airport and other industries. These services include pulverized coal and petroleum coke supply, power

generation, steam production, chilled water production, wastewater treatment and compressed air supply. At December 31, 2007, this segment owned and operated one gas-fired peaking electric generating plant and a biomass-fired electric generating plant. This segment also owned one additional coal-fired power plant that is currently not in service. This segment develops, owns and operates landfill gas recovery systems throughout the United States. In addition, this segment produces metallurgical coke from two coke batteries. The production of coke from these coke batteries generates production tax credits.

We expect to sell a 50 percent interest in a portfolio of select Power and Industrial Projects (Projects). In addition to the proceeds that the Company will receive from the sale of the 50 percent equity interest, the company that will own the Projects will obtain debt financing and the proceeds will be distributed to DTE Energy immediately prior to the sale of the equity interest. The total gross proceeds the Company will receive are expected to approximate \$650 million. The Company expects to complete the transaction in the first half of 2008. This timing, however, is highly dependent on availability of acceptable financing terms in the credit markets. As a result, the Company cannot predict the timing with certainty. The Company expects to recognize a gain upon completion of the transaction. In conjunction with the sale, the Company will enter into a management services agreement to manage the day-to-day operations of the Projects and to act as the managing member of the company that owns the Projects. We plan to account for our 50 percent ownership interest in the company that will own the portfolio of Projects using the equity method. See Note 3 of the Notes to Consolidated Financial Statements.

In July 2007, we sold Georgetown, an 80 Megawatt (MW) natural gas-fired peaking electric generating plant for approximately \$23 million, which approximated our carrying value. In October 2007, we sold our 50 percent interest in Crete, a 320 MW natural gas-fired peaking electric generating plant for approximately \$37 million, and recognized a pre-tax gain of approximately \$8 million (\$5 million after-tax). See Note 3 of the Notes to Consolidated Financial Statements.

## Energy Trading

Energy Trading focuses on physical power and gas marketing and trading, structured transactions, enhancement of returns from DTE Energy's asset portfolio and the optimization of contracted natural gas pipelines and storage, and power transmission and generating capacity positions. Our customer base is predominantly utilities, local distribution companies, pipelines, and other marketing and trading companies. We enter into derivative financial instruments as part of our marketing and hedging activities. Most of the derivative financial instruments are accounted for under the mark-to-market method, which results in the recognition of unrealized gains and losses from changes in the fair value of the derivatives in our results of operations. We utilize forwards, futures, swaps and option contracts to mitigate risk associated with our marketing and trading activity as well as for proprietary trading within defined risk guidelines. Energy Trading provides commodity risk management services to the other businesses within DTE Energy.

Significant portions of the electric and gas marketing and trading portfolio are economically hedged. The portfolio includes financial instruments and gas inventory, as well as contracted natural gas

pipelines and storage and power generation capacity positions. Most financial instruments are deemed derivatives, whereas the gas inventory, power transmission, pipelines and storage assets are not derivatives. As a result, this segment may experience earnings volatility as derivatives are marked-to-market without revaluing the underlying non-derivative contracts and assets. This results in gains and losses that are recognized in different accounting periods. We may incur mark-to-market accounting gains or losses in one period that could reverse in subsequent periods.

## Discontinued Operations

### Synthetic Fuel

The Synthetic Fuel business had been shown as a non-utility segment through the third quarter of 2007. Due to the expiration of synfuel production tax credits at the end of 2007, the Synthetic Fuel business ceased operations and has been classified as a discontinued operation as of December 31, 2007. Synfuel plants chemically changed coal and waste coal into a synthetic fuel as determined under the Internal Revenue Code. Production tax credits were provided for the production and sale of solid synthetic fuel produced from coal and were available through December 31, 2007. To optimize income and cash flow from the synfuel operations, we had sold interests in all nine of the facilities, representing 91% of the total production capacity as of December 31, 2007. The synthetic fuel plants generated operating losses that were substantially offset by production tax credits.

The value of a production tax credit is adjusted annually by an inflation factor and published annually by the Internal Revenue Service (IRS). The value is reduced if the Reference Price of a barrel of oil exceeds certain thresholds. The actual tax credit phase-out for 2007 will not be certain until the Reference Price is published by the IRS in April 2008.

## Operating System And Performance Excellence Process

We continuously review and adjust our cost structure and seek improvements in our processes. Beginning in 2002, we adopted the DTE Energy Operating System, which is the application of tools and operating practices that have resulted in operating efficiencies, inventory reductions and improvements in technology systems, among other enhancements.

As an extension of this effort, in mid-2005, we initiated a company-wide review of our operations called the Performance Excellence Process. The overarching goal has been and remains to become more competitive by reducing costs, eliminating waste and optimizing business processes while improving customer service. Many of our customers are under intense economic pressure and will benefit from our efforts to keep down our costs and their rates. Additionally, we will need significant resources in the future to invest in the infrastructure required to provide safe, reliable and affordable energy. Specifically, we began a series of focused improvement initiatives within our Electric and Gas Utilities, and our corporate support function. The process is rigorous and challenging and seeks to yield sustainable performance improvements to our customers and shareholders. We have identified the Performance Excellence Process as critical to our long-term growth strategy. In order to fully

realize the benefits from the Performance Excellence Process, it is necessary to make significant up-front investments in our infrastructure and business processes. The costs to achieve (CTA) in 2006 exceeded our savings, but we began to realize sustained net cost savings in 2007.

In September 2006, the MPSC issued an order approving a settlement agreement that allows Detroit Edison and MichCon, commencing in 2006, to defer the incremental CTA. Further, the order provides for Detroit Edison and MichCon to amortize the CTA deferrals over a ten-year period beginning with the year subsequent to the year the CTA was deferred. Detroit Edison deferred approximately \$102 million of CTA in 2006 as a regulatory asset and began amortizing deferred 2006 costs in 2007 as the recovery of these costs was provided for by the MPSC in the order approving the settlement in the show cause proceeding. Amortization of prior year deferred CTA costs amounted to \$10 million in 2007. During 2007, CTA costs of approximately \$54 million were deferred. MichCon cannot defer CTA costs at this time because a regulatory recovery mechanism has not been established by the MPSC. MichCon expects to seek a recovery mechanism in its next rate case in 2009.

## Capital Investment

We anticipate significant capital investment across all of our business segments. Most of our capital expenditures will be concentrated within our utility segments. Our electric utility segment currently expects to invest approximately \$5.2 billion (excluding investments in new generation capacity, if any), including increased environmental requirements and reliability enhancement projects during the period of 2008 through 2012. Our gas utility segment currently expects to invest approximately \$1.0 billion on system expansion, pipeline safety and reliability enhancement projects through the same period. We plan to seek regulatory approval to include these capital expenditures within our regulatory rate base consistent with prior treatment.

## Enterprise Business Systems

In 2003, we began the development of our Enterprise Business Systems (EBS) project, an enterprise resource planning system initiative to improve existing processes and to implement new core information systems, relating to finance, human resources, supply chain and work management. As part of this initiative, we have implemented EBS software including, among others, products developed by SAP AG. The first phase of implementation occurred in 2005 in the regulated electric fossil generation unit. The second phase of implementation began in April 2007 and was completed by the end of 2007. The total capital cost of implementation was approximately \$385 million. We expect the benefits of lower costs, faster business cycles, repeatable and optimized processes, enhanced internal controls, improvements in inventory management and reductions in system support costs to outweigh the expense of our investment in this initiative.

## Outlook

The next few years will be a period of rapid change for DTE Energy and for the energy industry. Our strong utility base, combined with our integrated non-utility operations, position us well for long-term growth.

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

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

Along with pursuing a leaner organization, we anticipate approximately \$200 million of synfuel-related cash impacts in 2008 and 2009, which consists of cash from operations and proceeds from option hedges, including approximately \$100 million of tax credit carryforward utilization and other tax benefits that are expected to reduce future tax payments. As part of a strategic review of our non-utility operations, we have taken and continue to pursue various actions including the sale, restructuring or recapitalization of certain non-utility businesses that generated approximately \$900 million in after-tax cash proceeds in 2007 and are expected to generate an additional approximately \$800 million in 2008. We have used approximately \$725 million to repurchase common stock and approximately \$500 million to redeem outstanding debt. In 2008, upon completion of our remaining monetization activities, we expect to repurchase an additional approximately \$275 million of common stock and to use approximately \$200 million to redeem outstanding debt, assuming the expected asset sales occur. Our objectives for cash redeployment are to increase shareholder value, strengthen the balance sheet and coverage ratios to improve our current credit rating and outlook, and to have any monetizations be accretive to earnings per share.

We performed an assessment during the fourth quarter of 2007 to determine the impact, if any, of the current conditions in the credit markets on our operations. We believe that our access to financing at reasonable interest rates, the fair value of assets held in trust to satisfy future obligations under our pension plans, and our counterparties' creditworthiness will not be significantly affected by current conditions in the credit market.

## Results Of Operations

Net income in 2007 was \$971 million, or \$5.70 per diluted share, compared to net income of \$433 million, or \$2.43 per diluted share in 2006 and net income of \$537 million, or \$3.05 per diluted share in 2005. Excluding discontinued operations and the cumulative effect of accounting changes, our income from continuing operations in 2007 was \$787 million, or \$4.62 per diluted share, compared to income of \$389 million, or \$2.18 per diluted share in 2006 and income of \$272 million, or \$1.55 per diluted share in 2005. The following sections provide a detailed discussion of our segments' operating performance and future outlook.

Based on the following structure, we set strategic goals, allocate resources and evaluate performance:

- **Electric Utility**, consisting of Detroit Edison;
- **Gas Utility**, primarily consisting of MichCon;
- **Non-utility Operations**
  - **Coal and Gas Midstream**, primarily consisting of coal transportation and marketing, gas pipelines and storage;
  - **Unconventional Gas Production**, primarily consisting of unconventional gas project development and production;
  - **Power and Industrial Projects**, primarily consisting of on-site energy services, steel-related projects and power generation with services;
  - **Energy Trading**, consisting of energy marketing and trading operations; and
- **Corporate & Other**, primarily consisting of corporate staff functions that are fully allocated to the various segments based on services utilized. Additionally, Corporate & Other holds certain non-utility debt and energy-related investments.

The Synthetic Fuel business had been shown as a non-utility segment through the third quarter of 2007. Due to the expiration of synfuel production tax credits at the end of 2007, the Synthetic Fuel business ceased operations and has been classified as a discontinued operation as of December 31, 2007.

<i>(in Millions)</i>	2007	2006	2005
<b>Net Income by Segment:</b>			
Electric Utility	\$ 317	\$ 325	\$ 277
Gas Utility	70	50	37
Non-utility Operations:			
Coal and Gas Midstream	53	50	45
Unconventional Gas Production (1)	(217)	9	4
Power and Industrial Projects	30	(80)	4
Energy Trading	32	96	(43)
Corporate & Other (1)	502	(61)	(52)
<b>Income (Loss) from Continuing Operations:</b>			
Utility	387	375	314
Non-utility	(102)	75	10
Corporate & Other	502	(61)	(52)
	<b>787</b>	<b>389</b>	<b>272</b>
Discontinued Operations	184	43	268
Cumulative Effect of Accounting Changes	–	1	(3)
<b>Net Income</b>	<b>\$ 971</b>	<b>\$ 433</b>	<b>\$ 537</b>

(1) 2007 Net Loss of the Unconventional Gas Production segment resulted principally from the recognition of losses on hedge contracts associated with the Antrim sale transaction. 2007 Net Income of the Corporate & Other segment resulted principally from the gain recognized on the Antrim sale transaction. See Note 3 of the Notes to the Consolidated Financial Statements.

## Electric Utility

Our Electric Utility segment consists of Detroit Edison.

**Factors impacting income:** Our net income decreased \$8 million in 2007 and increased \$48 million in 2006. The 2007 decrease reflects higher operation and maintenance expenses, partially offset by higher gross margins and lower depreciation and amortization expenses. The 2006 increase primarily reflects higher gross margins, partially offset by increased depreciation and amortization expenses.

(in Millions)	2007	2006	2005
Operating Revenues	\$ 4,900	\$ 4,737	\$ 4,462
Fuel and Purchased Power	1,686	1,566	1,590
Gross Margin	3,214	3,171	2,872
Operation and Maintenance	1,422	1,336	1,308
Depreciation and Amortization	764	809	640
Taxes Other Than Income	277	252	241
Asset (Gains) and Losses, Net	8	(6)	(26)
Operating Income	743	780	709
Other (Income) and Deductions	277	294	283
Income Tax Provision	149	161	149
Net Income	\$ 317	\$ 325	\$ 277

Operating Income as a Percent of Operating Revenues	15%	16%	16%
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**Gross margin** increased \$43 million during 2007 and \$299 million in 2006. The increase in 2007 was attributed to higher margins due to returning sales from electric Customer Choice, the favorable impact of a May 2007 MPSC order related to the 2005 Power Supply Cost Recovery (PSCR) reconciliation and weather related impacts, partially offset by lower rates resulting primarily from the August 2006 settlement in the MPSC show cause proceeding and the unfavorable impact of a September 2006 MPSC order related to the 2004 PSCR reconciliation. The 2006 improvement was primarily due to increased rates due to the expiration of the residential rate cap on January 1, 2006 and returning sales from electric Customer Choice, partially offset by milder weather. Revenues include a component for the cost of power sold that is recoverable through the PSCR mechanism.

The following table displays changes in various gross margin components relative to the comparable prior period:

(in Millions)	2007	2006
<b>Increase (Decrease) in Gross Margin Components Compared to Prior Year</b>		
Weather-related margin impacts	\$ 31	\$ (81)
Removal of residential rate caps effective January 1, 2006	—	186
Return of customers from electric Customer Choice	43	156
Service territory economic performance	28	(16)
Impact of 2006 MPSC show cause order	(64)	—
Impact of 2005 MPSC PSCR reconciliation order	38	—
Impact of 2004 MPSC PSCR reconciliation order	(39)	26
Other, net	6	28
Increase in gross margin	\$ 43	\$ 299

(in Thousands of Megawatthours of Electricity (MWh))

	2007		2006		2005	
<b>Power Generated and Purchased</b>						
Power Plant Generation						
Fossil	42,359	72%	39,686	70%	40,756	73%
Nuclear	8,314	14	7,477	13	8,754	16
	50,673	86	47,163	83	49,510	89
Purchased Power	8,422	14	9,861	17	6,378	11
System Output	59,095	100%	57,024	100%	55,888	100%
Less Line Loss and Internal Use	(3,391)		(3,603)		(3,205)	
Net System Output	55,704		53,421		52,683	

### Average Unit Cost (\$/MWh)

Generation (1)	\$ 15.83	\$ 15.61	\$ 15.47
Purchased Power (2)	\$ 62.40	\$ 53.71	\$ 89.37
Overall Average Unit Cost	\$ 22.47	\$ 22.20	\$ 23.90

(1) Represents fuel costs associated with power plants.

(2) The change in purchased power costs were driven primarily by seasonal demand and coal and gas prices.

(in Thousands of MWh)

	2007	2006	2005
<b>Electric Sales</b>			
Residential	16,147	15,769	16,812
Commercial	19,332	17,948	15,618
Industrial	13,338	13,235	12,317
Wholesale	2,902	2,826	2,329
Other	398	402	390
	52,117	50,180	47,466
Interconnection sales (1)	3,587	3,241	5,217
Total Electric Sales	55,704	53,421	52,683

### Electric Deliveries

Retail and Wholesale	52,117	50,180	47,466
Electric Customer Choice	1,690	2,694	6,760
Electric Customer Choice – Self Generators (2)	549	909	518
Total Electric Sales and Deliveries	54,356	53,783	54,744

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

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

**Operation and maintenance** expense increased \$86 million in 2007 and \$28 million in 2006. The increase in 2007 is primarily due to EBS implementation costs of \$30 million, higher storm expenses of \$22 million, increased uncollectible expense of \$22 million and higher corporate support expenses of \$20 million. The 2006 increase was primarily due to increased distribution system maintenance of \$35 million and increased plant outage costs of \$33 million, partially offset by \$36 million of lower storm expenses.

**Depreciation and amortization** expense decreased \$45 million in 2007 and increased \$169 million in 2006. The 2007 decrease was due primarily to a 2006 net stranded cost write-off of \$112 million related to the September 2006 MPSC order regarding stranded costs and a \$13 million decrease in our asset retirement obligation at our Fermi 1 nuclear facility, partially offset by \$58 million of increased

amortization of regulatory assets and \$13 million of higher depreciation expense due to increased levels of depreciable plant assets. Amortization of prior year deferred CTA costs amounted to \$10 million in 2007. The 2006 increase was due to a \$112 million net stranded cost write-off related to the September 2006 MPSC order regarding stranded costs and a \$19 million increase in our asset retirement obligation at our Fermi 1 nuclear facility. In 2006, we also had increased amortization of regulatory assets of \$19 million related to electric Customer Choice and \$8 million related to our securitized assets.

**Asset (gains) and losses, net** gain decreased \$14 million in 2007 due to a \$13 million reserve for a loan guaranty related to Detroit Edison's former ownership of a steam heating business now owned by Thermal Ventures II, LP. The 2006 decrease resulted primarily from our 2005 sale of land near our headquarters in Detroit, Michigan.

**Other (income) and deductions** expense decreased \$17 million in 2007 and increased \$11 million in 2006. The 2007 decrease is attributable to a \$10 million contribution to the DTE Energy Foundation in 2006 that did not re-occur in 2007, \$3 million of higher interest income and \$17 million of increased miscellaneous utility related services, partially offset by \$16 million of higher interest expense. The 2006 increase is primarily attributable to higher interest expense due to increased long-term debt.

**Outlook** – We will move forward in our efforts to continue to improve the operating performance of Detroit Edison. We continue to resolve outstanding regulatory issues and continue to pursue additional regulatory and/or legislative solutions for structural problems within the Michigan electric market structure, primarily electric Customer Choice and the need to adjust rates for each customer class to reflect the full cost of service. We are also seeking regulatory reform to insure more timely cost recovery and resolution of rate cases. Looking forward, additional issues, such as rising prices for coal, health care and higher levels of capital spending, will result in us taking meaningful action to address our costs while continuing to provide quality customer service. We will utilize the DTE Energy Operating System and the Performance Excellence Process to seek opportunities to improve productivity, remove waste and decrease our costs while improving customer satisfaction.

Long term, we will be required to invest an estimated \$2.4 billion on emission controls through 2018. We intend to seek recovery of these investments in future rate cases.

Additionally, our service territory may require additional generation capacity. A new base-load generating plant has not been built within the State of Michigan in over 20 years. Should our regulatory environment be conducive to such a significant capital expenditure, we may build, upgrade or co-invest in a base-load coal facility or a new nuclear plant. While we have not decided on construction of a new base-load nuclear plant, in February 2007, we announced that we will prepare a license application for construction and operation of a new nuclear power plant on the site of Fermi 2. By completing the license application before the end of 2008, we may qualify for financial incentives under the Federal Energy Policy Act of 2005. We are also studying the possible transfer of a gas-fired peaking electric generating plant from our non-utility operations to our electric utility to support future power generation requirements.

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

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

We expect cash flows and operating performance will continue to be at risk due to the electric Customer Choice program until the issues associated with this program are adequately addressed. We will accrue as regulatory assets any future unrecovered generation-related fixed costs (stranded costs) due to electric Customer Choice that we believe are recoverable under Michigan legislation and MPSC orders. We cannot predict the outcome of these matters. See Note 5 of the Notes to Consolidated Financial Statements.

In January 2007, the MPSC submitted the State of Michigan's 21st Century Energy Plan to the Governor of Michigan. The plan recommends that Michigan's future energy needs be met through a combination of renewable resources and cleanest generating technology, with significant energy savings achieved by increased energy efficiency. The plan also recommends:

- a requirement that all retail electric suppliers obtain at least 10 percent of their energy supplies from renewable resources by 2015;
- an opportunity for utility-built generation, contingent upon the granting of a certificate of need and competitive bidding of engineering, procurement and construction services;
- investigating the cost of a requirement to bury certain power lines; and
- creation of a Michigan Energy Efficiency Program, administered by a third party under the direction of the MPSC with initial funding estimated at \$68 million.

In December 2007, a package of bills to reform Michigan's electric market was introduced in the Michigan legislature. Key elements of the package would modify Michigan's electric Customer Choice program, begin the process of "de-skewing" regulated electric rates, provide for the creation of economic development rates, establish a process for authorizing the construction of new baseload power plants, provide for regulatory reform to insure more timely cost recovery and resolution of rate cases, establish renewable energy standards and create an energy efficiency program.

We continue to review the energy plan and monitor legislative action on some of its components. Without knowing how or if the plan will be fully implemented, we are unable to predict the impact on the Company of the implementation of the plan.

## Gas Utility

Our Gas Utility segment consists of MichCon and Citizens.

Factors impacting income: Gas Utility's net income increased \$20 million in 2007 and \$13 million in 2006. The 2007 and 2006 increases were due primarily to higher gross margins.

<i>(in Millions)</i>	2007	2006	2005
Operating Revenues	\$ 1,875	\$ 1,849	\$ 2,138
Cost of Gas	1,164	1,157	1,490
Gross Margin	711	692	648
Operation and Maintenance	429	431	424
Depreciation and Amortization	93	94	95
Taxes Other Than Income	56	53	43
Asset (Gains) and Losses, Net	(3)	—	4
Operating Income	136	114	82
Other (Income) and Deductions	43	53	47
Income Tax Provision (Benefit)	23	11	(2)
Net Income	\$ 70	\$ 50	\$ 37
Operating Income as a Percent of Operating Revenues	7%	6%	4%

**Gross margin** increased \$19 million and \$44 million in 2007 and 2006, respectively. The increase in 2007 is primarily due to \$21 million from the favorable effects of weather in 2007 and \$28 million related to an increase in midstream services including storage and transportation, partially offset by a \$26 million unfavorable impact in lost gas recognized and \$7 million in GCR disallowances. The increase in 2006 is primarily due to \$15 million in higher base rates and \$22 million in higher revenue associated with the uncollectible expense tracking mechanism authorized by the MPSC in the April 2005 gas rate order. Additionally, 2006 was impacted by a \$17 million favorable impact in lost gas recognized and an increase of \$24 million in midstream services including storage and transportation. Partially offsetting these increases were declines of \$31 million due to warmer than normal weather and \$26 million as a result of customer conservation and lower volumes. The comparability of 2006 to 2005 is also affected by an adjustment we recorded in the first quarter of 2005 related to an April 2005 MPSC order in our 2002 GCR reconciliation case that disallowed \$26 million representing unbilled revenues at December 31, 2001. Revenues include a component for the cost of gas sold that is recoverable through the GCR mechanism.

	2007	2006	2005
<b>Gas Markets (in Millions)</b>			
Gas sales	\$ 1,536	\$ 1,541	\$ 1,860
End user transportation	140	135	134
	1,676	1,676	1,994
Intermediate transportation	59	69	58
Storage and other	140	104	86
	\$ 1,875	\$ 1,849	\$ 2,138
<b>Gas Markets (in Bcf)</b>			
Gas sales	148	138	168
End user transportation	132	136	157
	280	274	325
Intermediate transportation	399	373	432
	679	647	757

**Operation and maintenance** expense decreased \$2 million in 2007 and increased \$7 million in 2006. The 2007 decrease was attributed to \$4 million of lower uncollectible expense and \$4 million of reduced corporate support expenses, partially offset by \$5 million in increased EBS implementation costs. The 2006 increase is due to \$14 million of higher uncollectible expense and \$24 million in implementation costs associated with our Performance Excellence Process, partially offset by \$9 million of lower injuries and damages expenses and lower labor and employee incentives. The comparability of 2006 to 2005 was affected by an adjustment we recorded in the second quarter of 2005 for the disallowance of \$11 million in environmental costs due to the April 2005 gas rate order and the requirement to defer negative pension expense as a regulatory liability. Additionally, the comparability was impacted by the DTE Energy parent company no longer allocating \$9 million of merger-related interest to MichCon effective in April 2005.

**Asset (gains) and losses, net** gain increased \$3 million in 2007 and increased \$4 million in 2006. The 2007 increase is attributable to the sale of base gas. The 2006 increase is attributable to the write-off of certain computer equipment and related depreciation resulting from the April 2005 gas rate order.

**Outlook** – Operating results are expected to vary due to regulatory proceedings, weather, changes in economic conditions, customer conservation, process improvements and base gas sales. Higher gas prices and economic conditions have resulted in continued pressure on receivables and working capital requirements that are partially mitigated by the MPSC's uncollectible true-up mechanism and GCR mechanism.

We will continue to utilize the DTE Energy Operating System and the Performance Excellence Process to seek opportunities to improve productivity, remove waste and decrease our costs while improving customer satisfaction.

## Non-Utility Operations

### Coal and Gas Midstream

Our Coal and Gas Midstream segment consists of Coal Transportation and Marketing and the Pipelines, Processing and Storage businesses.

**Factors impacting income:** Net income increased \$3 million and \$5 million in 2007 and 2006, respectively. Net income was higher in 2007 due to higher midstream gas storage revenues, offset by increased overhead related to legal expenses.

<i>(in Millions)</i>	2007	2006	2005
Operating Revenues	\$ 837	\$ 707	\$ 707
Operation and Maintenance	747	628	653
Depreciation and Amortization	8	4	3
Taxes Other Than Income	5	5	4
Asset (Gains) and Losses, Net	(1)	—	—
Operating Income	78	70	47
Other (Income) and Deductions	(5)	(8)	(20)
Income Tax Provision	30	28	22
Net Income	\$ 53	\$ 50	\$ 45

**Operating revenues** increased \$130 million in 2007 and remained the same in 2006. In 2007, revenues were impacted by increases in our Coal and Transportation business based on higher synfuel related volumes and increases in trading volumes related to both coal and emissions. Revenues were also favorably impacted by higher midstream gas storage revenues in our Pipelines, Processing and Storage business. In 2006, our Coal Transportation and Marketing business experienced lower synfuel related volumes, which were offset by an increase in storage revenues in the Pipelines, Processing and Storage business.

**Operation and maintenance expense** increased \$119 million in 2007 and decreased \$25 million in 2006. The 2007 increase was due to increased Coal Transportation and Marketing volume related to higher synfuel related volumes and higher trading volumes related to coal and emissions.

The 2006 decrease was due to decreased expenses at our Coal Transportation and Marketing business due to decreased marketing volume.

**Other (income) and deductions** income decreased \$3 million in 2007 and \$12 million in 2006. The 2007 and 2006 decreases are primarily attributable to higher interest expense as a result of our expansion of owned storage.

**Outlook** – In 2008, we expect to see a decrease in net income since approximately \$11 million of our 2007 Coal Transportation and Marketing net income was dependent upon our Synfuel operations that ceased operations at the end of 2007. Beyond 2008, we expect to continue to grow our Coal Transportation and Marketing business in a manner consistent with, and complementary to, the growth of our other business segments.

Our Pipelines, Processing and Storage business expects to continue its steady growth plan. In April 2007, Washington 28 received MPSC approval to increase working gas storage capacity by over 6 Bcf to a total of 16 Bcf by April 2008. In June 2007, Washington 10 received MPSC approval to develop the Shelby 2 storage field which will increase the working gas storage capacity of Washington 10 over the next two years by 8 Bcf to a total of 74 Bcf. Vector Pipeline placed into service its Phase 1 expansion for approximately 200 MMcf/d in November 2007. This project is fully supported by customers with long-term agreements. In addition, Vector Pipeline requested permission from the FERC in the fourth quarter of 2007 to build one more compressor station and to expand the Vector Pipeline by approximately 100 MMcf/d, with a proposed in-service date of November 1, 2009. Adding another compressor station will bring the system from its current capacity of about 1.2 Bcf/d up to 1.3 Bcf/d in 2009. Pipelines, Processing and Storage has a 26 percent ownership interest in Millennium Pipeline which commenced construction in June 2007 and is scheduled to be in service in late 2008. We plan to expand existing assets and develop new assets which are typically supported with long-term customer commitments.

### Unconventional Gas Production

Our Unconventional Gas Production business is engaged in natural gas exploration, development and production primarily within the Barnett shale in north Texas. On June 29, 2007, we sold our Antrim shale gas exploration and production business in the northern lower peninsula of Michigan for gross proceeds of \$1.262 billion. The gain

on sale is included in the Corporate & Other segment. See Note 3 of the Notes to Consolidated Financial Statements.

**Factors impacting income:** Net income decreased \$226 million in 2007 and increased \$5 million in 2006. The significant decline in results in 2007 reflects the recording of losses on financial contracts that hedged our price risk exposure related to expected Antrim gas production and sales and impairments of our southern expansion area of the Barnett shale in 2007. The 2006 results were primarily impacted by an increase in Barnett shale production and an increase in net gas prices for Antrim shale. Partially offsetting these revenue increases were higher operating and depletion expenses associated with increased production and the operation of new wells.

<i>(in Millions)</i>	<b>2007</b>	2006	2005
Operating Revenues	\$ (228)	\$ 99	\$ 74
Operation and Maintenance	36	37	30
Depreciation, Depletion and Amortization	22	27	20
Taxes Other Than Income	8	11	11
Asset (Gains) and Losses, Net	27	(3)	–
Operating Income (Loss)	(321)	27	13
Other (Income) and Deductions	13	13	8
Income Tax Provision (Benefit)	(117)	5	1
Net Income (Loss)	\$ (217)	\$ 9	\$ 4

**Operating revenues** decreased \$327 million in 2007. The decrease for 2007 was due to the recording of \$323 million of losses on financial contracts that hedged our price risk exposure related to expected Antrim gas production and sales through 2013. These financial contracts were accounted for as cash flow hedges, with changes in estimated fair value of the contracts reflected in other comprehensive income. Upon the sale of Antrim, the financial contracts no longer qualified as cash flow hedges. The contracts were retained and offsetting financial contracts were put into place to effectively settle these positions. As a result of these transactions and market research performed by the Company, we gained additional insight and visibility into the value ascribed to these contracts by third party market participants for the duration of the contracts. In conjunction with the Antrim sale and effective settlement of these contract positions, Antrim reclassified amounts held in Accumulated other comprehensive income and recorded the effective settlements, reducing operating revenues in 2007 by \$323 million. Operating revenues increased \$25 million in 2006 due to increased Barnett shale production.

**Assets (gains) and losses, net** decreased \$30 million in 2007 primarily due to the recording of impairment losses of \$27 million in 2007 related to the write-off of unproved properties and the expiration of leases in the southern expansion area of the Barnett shale.

**Outlook** – On January 15, 2008, we sold a portion of our Barnett shale properties for gross proceeds of approximately \$250 million, subject to post-closing adjustments. We will recognize a gain on the sale in the first quarter of 2008. The properties in the sale included 186 Bcf of proved and probable reserves on approximately 11,000 net acres in the core area of the Barnett shale.

We plan to retain our holdings in the western portion of the Barnett shale and anticipate significant opportunities to develop our current position while accumulating additional acreage in and around our existing assets.

Current natural gas prices and successes within the Barnett shale are resulting in additional capital being invested into the area. The competition for opportunities and goods and services may result in increased operating costs, however, our experienced Barnett shale personnel provide an advantage in addressing potential cost increases.

We invested approximately \$140 million in the Barnett shale in 2007. During 2007, Barnett shale production was approximately 7.7 Bcfe of natural gas compared with approximately 4.1 Bcfe in 2006.

## Power and Industrial Projects

The Power and Industrial Projects segment is comprised primarily of projects that deliver utility-type products and services to industrial, commercial and institutional customers, and biomass energy projects.

**Factors impacting income:** Net income was \$30 million in 2007 compared to a net loss of \$80 million in 2006. The 2006 period reflects impairments at various businesses and projects.

<i>(in Millions)</i>	2007	2006	2005
Operating Revenues	\$ 473	\$ 409	\$ 428
Operation and Maintenance	409	366	329
Depreciation and Amortization	39	48	48
Taxes other than Income	11	12	14
Asset (Gains) and Losses, Reserves and Impairments, Net	—	75	(1)
Operating Income (Loss)	14	(92)	38
Other (Income) and Deductions	(13)	43	4
Minority Interest	2	1	37
Income Taxes			
Provision (Benefit)	6	(44)	5
Production Tax Credits	(11)	(12)	(12)
	(5)	(56)	(7)
Net Income (Loss)	\$ 30	\$ (80)	\$ 4

**Operating revenues** increased \$64 million in 2007 reflecting a new long-term utility services contract with a large automotive company, higher coke prices and sales volumes in addition to higher volumes at several other projects. Additionally, revenue was earned for a one-time success fee from the sale of an asset we operated for a third party. Revenues in 2006 decreased \$19 million due primarily to lower coke prices and lower pulverized coal sales. The 2006 decrease was partially offset by increased revenue from our on-site energy projects, reflecting the addition of new facilities, completion of new long-term utility services contracts with a large automotive company and a large manufacturer of paper products.

**Operation and maintenance** expense increased \$43 million in 2007 and \$37 million in 2006. The increases resulted from higher costs related to the addition of new facilities, a new long-term utility services contract with a large automotive company and higher volumes at several other projects.

**Depreciation and amortization** expense decreased \$9 million in 2007 due primarily to the suspension of \$6 million of depreciation expense in the fourth quarter of 2007 related to the assets held for sale, the sale of a generation facility during the year and reduced depreciation expense as a result of asset impairments at several biomass landfill sites in 2006.

**Asset (gains) and losses, reserves and impairments, net** expense decreased \$75 million in 2007 and increased \$76 million in 2006. In 2006, we recorded a \$42 million impairment for one of our 100% owned natural gas-fired generating plants and a \$14 million impairment at our landfill gas recovery unit relating to the write-down of long-lived assets at several landfill sites. Also, during 2006, we recorded a pre-tax impairment loss of \$19 million for the write down of fixed assets and patents at our waste coal recovery business.

**Other (income) and deductions** expense decreased \$56 million in 2007 and increased \$39 million in 2006 primarily due to a realized gain of \$8 million on the sale of a 50 percent equity interest in a natural gas-fired generating plant, a \$4 million gain recognized in 2007 on an installment sale of a coke battery facility, a reduction of \$5 million in interest expense and a \$32 million impairment of a 51% equity interest in a natural gas-fired generating plant in 2006.

**Outlook** – We expect to sell a 50 percent interest in a portfolio of select Power and Industrial Projects (Projects). In addition to the proceeds that the Company will receive from the sale of the 50 percent equity interest, the company that will own the Projects will obtain debt financing and the proceeds will be distributed to DTE Energy immediately prior to the sale of the equity interest. The total gross proceeds the Company will receive are expected to approximate \$650 million. The Company expects to complete the transaction in the first half of 2008. This timing, however, is highly dependent on availability of acceptable financing terms in the credit markets. As a result, the Company cannot predict the timing with certainty. The Company expects to recognize a gain upon completion of the transaction. In conjunction with the sale, the Company will enter into a management services agreement to manage the day-to-day operations of the Projects and to act as the managing member of the company that owns the Projects. We plan to account for our 50 percent ownership interest in the company that will own the portfolio of Projects using the equity method. See Note 3 of the Notes to Consolidated Financial Statements.

We have entered into a purchase and sale agreement to acquire the equity interests in a coke battery, with an estimated acquisition price of \$75 million. The closing of this acquisition is contingent upon the signing of a long-term coke sales agreement, which is currently in negotiation. We expect to close on this acquisition in the first half of 2008.

Power and Industrial Projects will continue leveraging its extensive energy-related operating experience and project management capability to develop and grow the on-site energy business.

## Energy Trading

Our Energy Trading segment focuses on physical power and gas marketing, structured transactions, enhancement of returns from DTE Energy's asset portfolio, optimization of contracted natural gas pipelines and storage, and power transmission and generating capacity positions.

Factors impacting income: Net income decreased \$64 million in 2007 and increased \$139 million in 2006. The decrease in 2007 was attributable to lower gross margins and an increase in other deductions. The 2006 increase is attributed to increased mark-to-market and realized power and gas positions that resulted from

significant 2005 mark-to-market losses on derivative contracts used to economically hedge our gas in storage and forward power contracts.

<i>(in Millions)</i>	2007	2006	2005
Operating Revenues	\$ 955	\$ 830	\$ 977
Fuel, Purchased Power and Gas	807	616	984
Gross Margin	148	214	(7)
Operation and Maintenance	58	65	43
Depreciation and Amortization	5	6	4
Taxes Other Than Income	1	1	(1)
Operating Income (Loss)	84	142	(53)
Other (Income) and Deductions	35	(3)	13
Income Tax Provision (Benefit)	17	49	(23)
Net Income (Loss)	\$ 32	\$ 96	\$ (43)

**Gross margin** decreased \$66 million in 2007 and increased \$221 million in 2006. The 2007 decrease is attributed to approximately \$30 million of unrealized losses for gas contracts related to revisions of valuation estimates for the long-dated portion of our energy contracts. Timing differences from 2005 that largely reversed and favorably impacted 2006 margin caused \$11 million of realized unfavorability in 2007. Additionally, margins were unfavorably impacted by \$13 million of lower realized gains from reduced merchant storage capacity in 2007 and \$12 million of unfavorability in realized power positions. The 2006 increase is attributed to a \$168 million mark-to-market increase on power and gas positions and a \$57 million increase in realized power and gas positions. The 2006 results reflect the timing differences from 2005 that largely reversed and favorably impacted earnings.

**Operation and maintenance** expense decreased \$7 million in 2007 and increased \$22 million in 2006. The 2007 decrease was due primarily to lower incentive expenses of \$7 million. The 2006 increase was due to higher incentive expenses of \$14 million resulting from our strong economic performance and higher corporate allocation charges of \$10 million.

**Other (income) and deductions** expense increased by \$38 million in 2007 and decreased by \$16 million in 2006. The 2007 increase is due to mark-to-market unfavorability on foreign currency swaps that economically hedge exposure on anticipated power sales and existing transportation positions that settle in Canadian dollars. The 2006 decrease is attributable to \$6 million of lower intercompany interest expense and \$8 million of higher affiliate interest income resulting from favorable operating cash flows to fund intercompany loans.

**Outlook** – Significant portions of the Energy Trading portfolio are economically hedged. The portfolio includes financial instruments and gas inventory, as well as capacity positions of natural gas storage, natural gas pipelines, and power transmission and full requirements contracts. The financial instruments are deemed derivatives, whereas the owned gas inventory, pipelines, transmission contracts, certain full requirements contracts and storage assets are not derivatives. As a result, we will experience earnings volatility as derivatives are marked-to-market without revaluing the underlying non-derivative assets. The majority of such earnings volatility is associated with the natural gas storage cycle, which does not coincide with the calendar year, but runs annually from April of one year to March of the next year. Our strategy is to economically

manage the price risk of storage with futures and over-the-counter forwards and swaps. This results in gains and losses that are recognized in different interim and annual accounting periods.

See “Fair Value of Contracts” section that follows.

## Corporate & Other

Corporate & Other includes various corporate staff functions. As these functions support the entire Company, their costs are fully allocated to the various segments based on services utilized. Therefore, the effect of the allocation on each segment can vary from year to year. Additionally, Corporate & Other holds certain non-utility debt and energy-related investments.

**Factors impacting income:** Corporate & Other results increased by \$563 million in 2007, which is primarily attributable to the gain on the sale of the Antrim shale gas exploration and production business of approximately \$900 million (\$580 million after-tax). Corporate & Other results declined by \$9 million in 2006, primarily due to higher Michigan Single Business Taxes.

## Discontinued Operations

### Synthetic Fuel

We discontinued the operations of our synthetic fuel production facilities throughout the United States as of December 31, 2007. Synfuel plants chemically changed coal and waste coal into a synthetic fuel as determined under the Internal Revenue Code. Production tax credits were provided for the production and sale of solid synthetic fuel produced from coal and were available through December 31, 2007.

**Factors impacting income:** Synthetic Fuel net income increased \$157 million in 2007 and decreased \$257 million in 2006. The increase in 2007 was due to synfuel production occurring throughout the year in comparison to 2006 when production was idled at all nine of our synfuel facilities from May to October 2006 and higher income from oil price hedges, partially offset by a higher phase-out of production tax credits due to high oil prices. The decline in 2006 was also due to higher oil prices resulting in reduced gains from selling interests in our synfuel plants, lower levels of production tax credits and asset impairments and reserves.

<i>(in Millions)</i>	2007	2006	2005
Operating Revenues	\$ 1,069	\$ 863	\$ 927
Operation and Maintenance	1,265	1,019	1,167
Depreciation and Amortization	(6)	24	58
Taxes other than Income	5	12	20
Asset (Gains) and Losses, Reserves and Impairments, Net (1)	(280)	40	(367)
Operating Income (Loss)	85	(232)	49
Other (Income) and Deductions	(9)	(20)	(34)
Minority Interest	(188)	(251)	(318)
Income Taxes			
Provision	98	14	139
Production Tax Credits	(21)	(23)	(43)
	77	(9)	96
Net Income (1)	\$ 205	\$ 48	\$ 305

(1) Includes intercompany pre-tax gain of \$32 million (\$21 million after-tax) for 2007.

**Operating revenues** increased \$206 million in 2007 and decreased \$64 million in 2006 due to synfuel production occurring throughout 2007 in comparison to 2006 when production was idled at all nine of our synfuel facilities from May to October 2006.

**Operation and maintenance** expense increased \$246 million in 2007 and decreased \$148 million in 2006 due to synfuel production occurring throughout 2007 in comparison to 2006 when production was idled at all nine of our synfuel facilities from May to October 2006.

**Depreciation and amortization** expense was lower by \$30 million in 2007 and \$34 million in 2006 as a result of reductions in asset retirement obligations in 2007 and the impairment of fixed assets at all nine synfuel projects in 2006.

**Asset (gains) and losses, reserves and impairments, net** gain increased \$320 million in 2007 and decreased \$407 million in 2006. The increase in gains in 2007 reflects the annual partner payment adjustment, recognition of certain fixed gains that were reserved during the comparable 2006 period, higher hedge gains and the impact of one-time impairment charges and fixed note reserves recorded in 2006. In 2007 and 2006, we deferred gains from the sale of the synfuel facilities, including a portion of gains related to fixed payments. Due to the increase in oil prices, we recorded accruals for contractual partners' obligations of \$130 million in 2007 and \$79 million in 2006 reflecting the probable refund of amounts equal to our partners' capital contributions or for operating losses that would normally be paid by our partners. In 2007, we reversed \$3 million of other synfuel-related reserves and impairments and in 2006 recorded \$78 million of other synfuel-related reserves and impairments. To economically hedge our exposure to the risk of an increase in oil prices and the resulting reduction in synfuel sales proceeds, we entered into derivative and other contracts. The derivative contracts are marked-to-market with changes in their fair value recorded as an adjustment to synfuel gains. We recorded net 2007 synfuel hedge mark-to-market gains of \$196 million compared with net 2006 synfuel hedge mark-to-market gains of \$60 million. See Note 15 of the Notes to Consolidated Financial Statements.

The following table displays the various pre-tax components that comprise the determination of synfuel gains and losses in 2007, 2006 and 2005.

<i>(in Millions)</i>	<b>2007</b>	2006	2005
<b>Components of Asset (Gains) Losses, Reserves and Impairments, Net</b>			
Gains recognized associated with fixed payments	<b>\$ (172)</b>	\$ (43)	\$ (132)
Gains recognized associated with variable payments	<b>(39)</b>	(14)	(187)
Reserves recorded for contractual partners' obligations	<b>130</b>	79	–
Other reserves and impairments, including partners' share (1)	<b>(3)</b>	78	–
Hedge (gains) losses:			
Hedges for 2005 exposure	–	–	(2)
Hedges for 2006 exposure	–	(66)	(40)
Hedges for 2007 exposure	<b>(196)</b>	6	(6)
	<b>\$ (280)</b>	\$ 40	\$ (367)

(1) Includes \$70 million in 2006, representing our partners' share of the asset impairment, included in Minority Interest.

**Minority interest** decreased by \$63 million and \$67 million in 2007 and 2006, respectively. The amounts reflect our partners' share of operating losses associated with synfuel operations, as well as our partners' \$70 million share of the asset impairment charges in 2006. The 2007 decrease reflects the decreased operating losses due to the 2006 one-time impairment charges, partially offset by increased production in 2007. The decrease in 2006 reflects reduced operating losses due to the idling of production at all nine of our synfuel facilities from May to October 2006, partially offset by our partners' \$70 million share of the asset impairment. The sale of interests in our synfuel facilities during prior periods resulted in allocating a larger percentage of such losses to our partners.

**Income taxes** increased \$86 million in 2007 and decreased \$105 million in 2006, reflecting changes in pre-tax income due to synfuel-related gains, loss reserves and the impairment of fixed assets in 2006.

**Outlook** – Synfuel production ceased on December 31, 2007. The value of a production tax credit is adjusted annually by an inflation factor and published annually by the IRS. The value is reduced if the Reference Price of a barrel of oil exceeds certain thresholds. The actual tax credit phase-out for 2007 will not be certain until the Reference Price is published by the IRS in April 2008, and is not expected to result in a material impact to the 2008 financial statements.

#### **DTE Georgetown (Georgetown)**

In the fourth quarter of 2006, management approved the marketing of Georgetown, an 80 Megawatt (MW) natural gas-fired peaking electric generating plant, for sale. In December 2006, Georgetown met the Statement of Financial Accounting Standards (SFAS) No. 144 criteria of an asset "held for sale" and we reported its operating results as a discontinued operation. The plant was sold in July 2007, resulting in gross proceeds of approximately \$23 million, which approximated our carrying value. Georgetown did not have significant business activity in 2007 and 2006.

#### **DTE Energy Technologies (Dtech)**

Dtech assembled, marketed, distributed and serviced distributed generation products, provided application engineering, and monitored and managed on-site generation system operations. In July 2005, management approved the restructuring of this business, resulting in the identification of certain assets and liabilities to be sold or abandoned, primarily associated with standby and continuous duty generation sales and service. Dtech did not have significant business activity in 2007 or 2006.

See Note 3 of the Notes to Consolidated Financial Statements.

## Cumulative Effect Of Accounting Changes

Effective January 1, 2007, we adopted Financial Accounting Standards Board (FASB) Interpretation No. (FIN) 48, *Accounting for Uncertainty in Income Taxes – an interpretation of FASB Statement No. 109*. The cumulative effect of the adoption of FIN 48 represented a \$5 million reduction to the January 1, 2007 balance of retained earnings.

Effective January 1, 2006, we adopted SFAS No. 123(R), *Share-Based Payment*, using the modified prospective transition method. The cumulative effect of the adoption of SFAS 123(R) was an increase in net income of \$1 million as a result of estimating forfeitures for previously granted stock awards and performance shares.

In the fourth quarter of 2005, we adopted FIN 47, *Accounting for Conditional Asset Retirement Obligations, an interpretation of SFAS No. 143* that required additional new accounting rules for asset retirement obligations. The cumulative effect of adopting these new accounting rules reduced 2005 earnings by \$3 million.

## Capital Resources And Liquidity

### Cash Requirements

We use cash to maintain and expand our electric and gas utilities and to grow our non-utility businesses, retire and pay interest on long-term debt and pay dividends. During 2007, our cash requirements were met primarily through operations and short-term borrowings. We believe that we will have sufficient internal and external capital resources to fund anticipated capital and operating requirements.

Our strategic direction anticipates base level capital investments and expenditures for existing businesses in 2008 of up to \$1.2 billion. The capital needs of our utilities will increase due primarily to environmental related expenditures. We may spend an additional \$300 million on growth-related projects within our non-utility businesses in 2008.

Capital spending is expected to increase in 2008 due to higher environmental expenditures. We incurred environmental expenditures of approximately \$219 million in 2007 and we expect over \$2 billion of future capital expenditures through 2018 to satisfy both existing and proposed new requirements.

We expect non-utility capital spending will approximate \$200 million to \$350 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 or remarketing in 2008 totals approximately \$450 million.

<i>(in Millions)</i>	2007	2006	2005
<b>Cash and Cash Equivalents</b>			
<b>Cash Flow From (Used For)</b>			
Operating activities:			
Net income	\$ 971	\$ 433	\$ 537
Depreciation, depletion and amortization	926	1,014	872
Deferred income taxes	144	28	147
Gain on sale of non-utility business	(900)	–	–
Gain on sale of synfuel and other assets, net and synfuel impairment	(253)	28	(405)
Working capital and other	237	(47)	(150)
	<b>1,125</b>	<b>1,456</b>	<b>1,001</b>
Investing activities:			
Plant and equipment expenditures – utility	(1,035)	(1,126)	(850)
Plant and equipment expenditures – non-utility	(264)	(277)	(215)
Acquisitions, net of cash acquired	–	(42)	(50)
Proceeds from sale of non-utility business	1,262	–	–
Proceeds from sale of synfuels and other assets	417	313	409
Restricted cash and other investments	(50)	(62)	(96)
	<b>330</b>	<b>(1,194)</b>	<b>(802)</b>
Financing activities:			
Issuance of long-term debt and common stock	50	629	1,041
Redemption of long-term debt	(393)	(687)	(1,266)
Short-term borrowings, net	(47)	291	437
Repurchase of common stock	(708)	(61)	(13)
Dividends on common stock and other	(370)	(375)	(366)
	<b>(1,468)</b>	<b>(203)</b>	<b>(167)</b>
Net Increase (Decrease) in Cash and Cash Equivalents	<b>\$ (13)</b>	<b>\$ 59</b>	<b>\$ 32</b>

### Cash from Operating Activities

A majority of our operating cash flow is provided by our electric and gas utilities, which are significantly influenced by factors such as weather, electric Customer Choice, regulatory deferrals, regulatory outcomes, economic conditions and operating costs. Our non-utility businesses also provide sources of cash flow to the enterprise, primarily from the synthetic fuels business, which we believe, subject to considerations discussed below, will provide up to approximately \$200 million of cash impacts in 2008 and 2009. We have reported the business activity of the synthetic fuel business as a discontinued operation as of December 31, 2007. Cash flow related to discontinued operations in 2007 includes a gain on sale of interests in synfuel projects of \$244 million, after adjusting for impairments, partners' share of synfuel project losses of \$188 million, and contributions from synfuel partners of \$229 million.

Cash from operations totaling \$1.1 billion in 2007 decreased \$331 million from the comparable 2006 period. The operating cash flow comparison primarily reflects a decrease in net income after adjusting for non-cash items (depreciation, depletion and amortization and deferred taxes) and gains on sales of businesses. The decrease was mostly driven by taxes attributable to our non-utility monetization program.

Cash from operations totaling \$1.5 billion in 2006 was up \$455 million from the comparable 2005 period. The operating cash flow comparison reflects an increase of \$352 million in net income, after adjusting for non-cash items (depreciation, depletion, amortization, deferred taxes and gains), and a \$103 million decrease in working capital and other requirements. Most of the improvement was driven by higher net income at Detroit Edison that was the result of improved revenues and gross margin stemming from a full year of higher rates granted in the 2004 electric rate orders and lower customer choice penetration. The working capital improvement was driven by MichCon and resulted primarily from declining GCR factors which had the effect of lowering customer accounts receivable balances. This improvement was partially offset by working capital requirements at Detroit Edison that resulted from pension and Voluntary Employees Beneficiary Association (VEBA) contributions totaling \$271 million in 2006.

**Outlook** – We expect cash flow from operations to increase over the long-term primarily due to improvements from higher earnings at our utilities. We have incurred costs associated with implementation of our Performance Excellence Process, but we began to realize sustained net cost savings in 2007. We also may be impacted by the delayed collection of underrecoveries of our PSCR and GCR costs and electric and gas accounts receivable as a result of MPSC orders. Gas prices are likely to be a source of volatility with regard to working capital requirements for the foreseeable future. We are continuing our efforts to identify opportunities to improve cash flow through working capital initiatives.

We anticipate approximately \$200 million of synfuel-related cash impacts in 2008, which consist of the final reconciliation of cash from synthetic fuel operations (related to activity prior to December 31, 2007), proceeds from option hedges, approximately \$100 million of tax credit carryforward utilization and other tax benefits that are expected to reduce future tax payments. The synthetic fuel business is reported as a discontinued operation as of December 31, 2007.

## Cash from Investing Activities

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

Net cash from investing activities increased \$1.5 billion in 2007, due primarily to the sale of our Antrim shale gas exploration and production business and lower capital expenditures.

Net cash outflows relating to investing activities increased \$392 million in 2006 compared to 2005. The 2006 change was primarily due to increased capital expenditures. The increase in capital expenditures was driven by environmental expenditures, EBS development and distribution projects at Detroit Edison, pipeline reliability and inventory management projects at MichCon, and growth-oriented projects across our non-utility segments.

We will continue to pursue opportunities to grow our businesses in a disciplined fashion if we can find opportunities that meet our strategic, financial and risk criteria.

## Cash from Financing Activities

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

Our strategy is to have a targeted debt portfolio blend of fixed and variable interest rates and maturity. We continually evaluate our leverage target, which is currently 50% to 52%, 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.

The current credit situation impacts our short-term financing activities, long-term financing activities, and the funding obligations of our defined benefit pension plans. In response, we have undertaken contingency planning efforts to mitigate any adverse impacts to our businesses resulting from the liquidity issues in the credit markets. We have performed an assessment of our ability to obtain financing and do not anticipate any issues with financing in the public or private markets in 2008. With respect to short-term financing, we have the ability to draw on bank lines if there is a further disruption in the commercial paper market. Additionally, a decrease in the fair value of our pension plan assets, which fluctuates based on current market conditions, could result in increased funding requirements to our pension plans. We will continue to monitor developments in the credit markets and the potential impacts on our business.

Net cash used for financing activities increased \$1.3 billion in 2007 primarily related to the repurchase of common stock, a decrease in short-term borrowings and the issuance of long-term debt, partially offset by lower debt redemptions.

Net cash used for financing activities increased \$36 million during 2006 compared to 2005, due mostly to a decrease in short-term borrowings and the issuance of common stock and long-term debt, partially offset by lower debt redemptions.

See Notes 11, 12, and 13 of the Notes to Consolidated Financial Statements.

We anticipate approximately \$200 million of synfuel-related cash impacts in 2008 and 2009, which consists of cash from operations and proceeds from option hedges, including approximately \$100 million of tax credit carryforward utilization and other tax benefits that are expected to reduce future tax payments. As part of a strategic review of our non-utility operations, we have taken and continue to pursue various actions including the sale, restructuring or recapitalization of certain non-utility businesses that generated approximately \$900 million in after-tax cash proceeds in 2007 and are expected to generate an additional approximately \$800 million in 2008. We have used approximately \$725 million to repurchase common stock and approximately \$500 million to redeem outstanding debt. In 2008, upon completion of our remaining monetization activities, we expect to repurchase an additional approximately \$275 million of common stock and to use approximately \$200 million to redeem outstanding debt, assuming the expected asset sales occur. Our objectives for cash redeployment are to increase shareholder value, strengthen the balance sheet and coverage ratios to improve our current credit rating and outlook, and to have any monetizations be accretive to earnings per share.

As of December 31, 2007, the Company had \$238 million of variable auction rate tax exempt bonds. These bonds, which are subject to rate reset every 7 days, are insured by bond insurers. Overall credit market conditions have resulted in credit rating downgrades and may result in future credit rating downgrades for the bond insurers. This has caused a loss in liquidity in the auction rate markets for their insured bonds. These conditions have negatively impacted interest rates, including default rates in the case of failed auctions. The Company does not expect its interest rate exposure regarding these bonds to be material. The Company plans to purchase and hold the bonds in a weekly rate mode until which time it can either refinance and reissue the bonds or convert the bonds to a longer-term mode.

## Contractual Obligations

The following table details our contractual obligations for debt redemptions, leases, purchase obligations and other long-term obligations as of December 31, 2007:

<i>(in Millions)</i>	Total	Less Than 1 Year	1-3 Years	4-5 Years	After 5 Years
<b>Contractual Obligations</b>					
Long-term debt:					
Mortgage bonds, notes and other (1)	\$ 5,933	\$ 327	\$ 750	\$1,053	\$3,803
Securitization bonds	1,185	120	272	314	479
Trust preferred-linked securities	289	—	—	—	289
Capital lease obligations (1)	106	15	29	21	41
Interest (1)	6,080	453	847	668	4,112
Operating leases (1)	233	44	64	43	82
Electric, gas, fuel, transportation and storage purchase obligations (2)	5,706	2,898	2,002	166	640
Other long-term obligations (1) (3)	154	43	45	27	39
<b>Total obligations</b>	<b>\$19,686</b>	<b>\$3,900</b>	<b>\$4,009</b>	<b>\$2,292</b>	<b>\$9,485</b>

(1) Includes obligations associated with assets held for sale of \$22 million of other long-term debt, \$33 million of capital lease obligations, \$9 million of interest, \$22 million of operating leases and other long-term obligations of \$94 million.

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

(3) Includes liabilities for unrecognized tax benefits of \$19 million.

## Credit Ratings

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

We have issued guarantees for the benefit of various non-utility subsidiaries. In the event that our credit rating is downgraded to below investment grade, certain of these guarantees would require us to post cash or letters of credit valued at approximately \$488 million at December 31, 2007. Additionally, upon a downgrade, our trading business could be required to restrict operations and our access to the short-term commercial paper market could be restricted or eliminated. While we currently do not anticipate such a downgrade, we cannot predict the outcome of current or future credit rating agency reviews. The following table shows our credit rating as determined by three nationally respected credit rating agencies. All ratings are considered investment grade and affect the value of the related securities.

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

## Critical Accounting Estimates

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

## Regulation

A significant portion of our business is subject to regulation. Detroit Edison and MichCon currently meet the criteria of 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. Management believes that currently available facts support the continued application of SFAS No. 71 and that all regulatory assets and liabilities are recoverable or refundable in the current rate environment. See Note 5 of the Notes to Consolidated Financial Statements.

## Risk Management and Trading Activities

Risk management and trading activities are accounted for in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended and interpreted. As amended, SFAS No. 133 establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts and for hedging activities. All derivatives are recorded at fair value and shown as "Assets or liabilities from risk management and trading activities" in the Consolidated Statements of Financial Position. Derivatives are measured at fair value, and changes in the fair value of the derivative instruments are recognized in earnings in the period of change, unless the derivative meets certain defined conditions and qualifies as an effective hedge. SFAS No. 133 also provides a scope exception for contracts that meet the normal purchase and sales criteria specified in the standard. The normal purchases and normal sales exception requires, among other things, physical delivery in quantities expected to be used or sold over a reasonable period in the normal course of business. Contracts that are designated as normal purchases and normal sales are not recorded at fair value. A majority of the contracts entered into by Detroit Edison and MichCon meet the criteria specified for this exception. The fair values of derivative contracts are determined from a combination of active quotes, published indexes and mathematical valuation models. Valuation models require various inputs and assumptions, including forward prices, volatility, interest rates, and exercise periods. The fair values we calculate for our derivatives may change significantly as inputs and assumptions are updated for new information. The cash returns we actually realize on our derivatives may be different from the results we estimate using models.

## 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 electricity and 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 2007 and 2006. We believe the allowance for doubtful accounts is based on reasonable estimates. As part of the 2005 gas rate order for MichCon, the MPSC provided for the establishment of an uncollectible accounts tracking mechanism that partially mitigates the impact associated with MichCon uncollectible expenses. However, failure to make continued progress in collecting our past due receivables in light of rising energy prices would unfavorably affect operating results and cash flow.

## Goodwill

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

As of December 31, 2007, our goodwill totaled \$2 billion. The majority of our goodwill is allocated to our utility reporting units. The value of the utility reporting units may be significantly impacted by rate orders and the regulatory environment.

Based on our 2007 goodwill impairment test, we determined that the fair value of our remaining operating reporting units exceeded their carrying value and no impairment existed. We will continue to monitor our estimates and assumptions regarding future cash flows. While we believe our assumptions are reasonable, actual results may differ from our projections.

## Pension and Postretirement Costs

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

We had pension costs for qualified pension plans of \$67 million in 2007 (including Special Termination Benefits of \$8 million), \$125 million in 2006 (including Special Termination Benefits of \$49 million), and \$90 million in 2005. Postretirement benefits costs for all plans were \$188 million in 2007 (including Special Termination Benefits of \$2 million), \$197 million in 2006 (including Special Termination Benefits of \$8 million), and \$155 million in 2005. Pension and postretirement benefits costs for 2007 are calculated based upon a number of actuarial assumptions, including an expected long-term rate of return on our plan assets of 8.75%. In developing our expected long-term rate of return assumption, we evaluated asset class risk and return expectations, as well as inflation assumptions. Projected returns are based on broad equity and bond markets. Our 2008 expected long-term rate of return on plan assets is based on an asset allocation assumption utilizing active investment management of 55% in equity markets, 20% in fixed income markets, and 25% invested in other assets. Because of market volatility, we periodically review our asset allocation and rebalance our portfolio when considered appropriate. Given market conditions, we believe that 8.75% is a reasonable long-term rate of return on our plan assets for 2008. We will continue to evaluate our actuarial assumptions, including our expected rate of return, at least annually.

We base our determination of the expected return on qualified plan assets on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation recognizes changes in fair value in a systematic manner over a three-year period. Accordingly, the future value of assets will be impacted as previously deferred gains or losses are recorded. We have unrecognized net gains due to the performance of the financial markets. As of December 31, 2007, 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 yield curve approach and a review of bonds that receive one of the two highest ratings given by a recognized rating agency. The yield curve approach matches projected plan pension and postretirement benefit payment streams with bond portfolios reflecting actual liability duration unique to our plans. The discount rate determined on this basis increased from 5.7% at December 31, 2006 to 6.5% at December 31, 2007. Due to recent company contributions, financial market performance and higher discount rates, we estimate that our 2008 total pension costs will approximate \$29 million compared to \$67 million in 2007 and our 2008 postretirement benefit costs will approximate \$146 million compared to \$188 million in 2007. 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 electric rate order. The tracking mechanism provides for the recovery or refunding of pension costs above or below the amount reflected in Detroit Edison's base rates. In April 2005, the MPSC approved the deferral of the non-capitalized portion of MichCon's negative pension expense. MichCon will record a regulatory liability for any negative pension costs, as determined under generally accepted accounting principles.

Lowering the expected long-term rate of return on our plan assets by one-percentage-point would have increased our 2007 qualified pension costs by approximately \$26 million. Lowering the discount rate and the salary increase assumptions by one-percentage-point would have increased our 2007 pension costs by approximately \$10 million. Lowering the health care cost trend assumptions by one-percentage-point would have decreased our postretirement benefit service and interest costs for 2007 by approximately \$24 million.

The market value of our pension and postretirement benefit plan assets has been affected in a positive manner by the financial markets. The value of our plan assets was \$3.5 billion at November 30, 2006 and \$3.8 billion at November 30, 2007. At December 31, 2006, we adopted SFAS No. 158 that required us to recognize the underfunded status of our pension and other postretirement plans. The impact of the adoption of SFAS No. 158 was an increase in pension and postretirement benefit liabilities of approximately \$1.3 billion in 2006. We requested and received agreement from the MPSC to record the additional liability amounts for the Detroit Edison and MichCon benefit plans on the Statements of Financial

Position as a Regulatory asset. As a result, Regulatory assets were increased by approximately \$1.2 billion. The remainder of the increase in pension and postretirement benefit liabilities is included in Accumulated other comprehensive loss, net of tax. At December 31, 2007 our qualified pension plans were overfunded by \$152 million, our non-qualified pension plans were underfunded by \$71 million, and our other postretirement benefit plans were underfunded by \$1.1 billion, reflected in noncurrent assets, current liabilities, and noncurrent liabilities, respectively. The improvement relative to 2006 results from Company contributions, investment performance returns, and increased discount rates.

Pension and postretirement costs and pension cash funding requirements may increase in future years without substantial returns in the financial markets. We made a \$180 million pension contribution in 2006 and made a \$150 million pension contribution in 2007. At the discretion of management and depending upon financial market conditions, we anticipate making up to a \$150 million contribution to our qualified pension plans in 2008 and up to \$400 million over the next five years. Also, we anticipate making up to a \$5 million contribution to our nonqualified benefit plans in 2008 and up to \$25 million over the next five years. We made a \$116 million contribution to our postretirement benefit plans in 2006 and made a \$76 million contribution to our postretirement benefit plans in 2007. At the discretion of management, and depending upon financial market conditions, we anticipate making up to a \$116 million contribution to our postretirement plans in 2008 and up to \$600 million over the next five years.

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 2007, \$17 million in 2006, and \$20 million in 2005.

See Note 17 of the Notes to Consolidated Financial Statements.

## Legal Reserves

We are involved in various legal proceedings, claims and litigation arising in the ordinary course of business. We regularly assess our liabilities and contingencies in connection with asserted or potential matters, and establish reserves when appropriate. Legal reserves are based upon management's assessment of pending and threatened legal proceedings and claims against us.

## Insured and Uninsured Risks

Our comprehensive insurance program provides coverage for various types of risks. Our insurance policies cover risk of loss including property damage, general liability, workers' compensation, auto liability, and directors' and officers' liability. Under our risk management policy, we self-insure portions of certain risks up to specified limits, depending on the type of exposure. The maximum self-insured retention for various risks is as follows: property damage – \$10 million, general liability – \$7 million, workers' compensation – \$8.5 million, and auto liability – \$7 million. We have an actuarially determined estimate of our incurred but not reported (IBNR) liability

prepared annually and we adjust our reserves for self-insured risks as appropriate. As of December 31, 2007, this IBNR liability was approximately \$40 million.

## Accounting for Tax Obligations

We are required to make judgments regarding the potential tax effects of various financial transactions and results of operations in order to estimate our obligations to taxing authorities. Beginning January 1, 2007, we began accounting for uncertain income tax positions using a benefit recognition model with a two-step approach, a more-likely-than-not recognition criterion and a measurement attribute that measures the position as the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement in accordance with FIN 48, *Accounting for Uncertainty in Income Taxes, an Interpretation of FASB Statement No. 109*. If the benefit does not meet the more likely than not criteria for being sustained on its technical merits, no benefit will be recorded. Uncertain tax positions that relate only to timing of when an item is included on a tax return are considered to have met the recognition threshold. Prior to January 1, 2007, we estimated uncertain income tax obligations in accordance with SFAS No. 109, *Accounting for Income Taxes*, SFAS No. 5, *Accounting for Contingencies* and Statement of Financial Accounting Concepts No. 6 (CON 6), *Elements of Financial Statements*. We also have non-income tax obligations related to real estate, sales and use and employment-related taxes and ongoing appeals related to these tax matters that are outside the scope of FIN 48 and accounted for under SFAS No. 5 and CON 6.

Accounting for tax obligations requires judgments, including assessing whether tax benefits are more likely than not to be sustained, and estimating reserves for potential adverse outcomes regarding tax positions that have been taken. We also assess our ability to utilize tax attributes, including those in the form of carryforwards, for which the benefits have already been reflected in the financial statements. We do not record valuation allowances for deferred tax assets related to capital losses that we believe will be realized in future periods. While we believe the resulting tax reserve balances as of December 31, 2007 and December 31, 2006 are appropriately accounted for in accordance with FIN 48, SFAS No. 5, SFAS No. 109 and CON 6 as applicable, the ultimate outcome of such matters could result in favorable or unfavorable adjustments to our consolidated financial statements and such adjustments could be material.

## Production Tax Credits

We generated production tax credits from our synfuel operations through December 31, 2007. Our coke battery and landfill gas recovery operations also generate production tax credits with varying expiration dates. We recognize earnings as tax credits are generated at our facilities in one of two ways. First, to the extent we have sold an interest in our synfuel facilities to third parties, we recognize gains as synfuel is produced and sold, and when there is persuasive evidence that the sales proceeds have become fixed or determinable, when probability of refund is considered remote and collectibility is reasonably assured. Second, to the extent we generate credits to our own account, we recognize earnings through reduced tax expense.

All production tax credits are subject to audit by the IRS. However, all of our synfuel facilities have received favorable private letter rulings from the IRS with respect to their operations. Audits of five of our synfuel facilities were successfully completed in the past two years. If production tax credits were disallowed in whole or in part as a result of an IRS audit, there could be a significant write-off of previously recorded earnings from such tax credits.

Tax credits generated by our facilities were \$217 million in 2007 as compared to \$295 million in 2006, and \$617 million in 2005. The portion of tax credits generated for our own account was \$31 million in 2007, as compared to \$35 million in 2006, and \$55 million in 2005, with the remaining credits generated allocated to third party partners.

Tax credits related to synfuels are classified as income from discontinued operations in our consolidated statement of operations.

## 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 (MDEQ) have aggressive programs to clean up contaminated property.

### Electric Utility

**Air** – Detroit Edison is subject to EPA ozone transport and acid rain regulations that limit power plant emissions of sulfur dioxide and nitrogen oxides. In March 2005, the EPA issued additional emission reduction regulations relating to ozone, fine particulate, regional haze and mercury air pollution. The new rules will lead to additional controls on fossil-fueled power plants to reduce nitrogen oxide, sulfur dioxide and mercury emissions. To comply with these requirements, Detroit Edison has spent approximately \$1.1 billion through 2007. We estimate Detroit Edison will incur future capital expenditures of up to \$282 million in 2008 and up to \$2.4 billion of additional capital expenditures through 2018 to satisfy both the existing and proposed new control requirements.

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

**Global Climate Change** – Proposals for voluntary initiatives and mandatory controls are being discussed in the United States to reduce greenhouse gases such as carbon dioxide, a by-product of burning fossil fuels. There may be legislative action to address the issue of changes in climate that result from the build up of greenhouse gases, including carbon dioxide, in the atmosphere. We cannot predict the impact any legislative or regulatory action may have on our operations and financial position.

**Water** – In response to an EPA regulation, currently under judicial review, Detroit Edison is required to examine alternatives for reducing the environmental impacts of the cooling water intake structures at several of its facilities. Based on the results of the studies to be conducted over the next several years, Detroit Edison may be required to install additional control technologies to reduce the impacts of the intakes. Initially, we estimated that we will incur up to approximately \$55 million over the next four to six years in additional capital expenditures to comply with these requirements. However, a recent court decision remanded back to the EPA several provisions of the federal regulation that has resulted in a delay in compliance requirements. The court decision also raised the possibility that we may have to install cooling towers at some facilities, substantially increasing capital expenditures. We cannot predict the effect on Detroit Edison of this court decision or any resulting regulations.

**Contaminated Sites** – Detroit Edison conducted remedial investigations at contaminated sites, including three former manufactured gas plant (MGP) sites, the area surrounding an ash landfill and several underground and aboveground storage tank locations. We have a reserve balance of \$15 million as of December 31, 2007 for the remediation of these sites over the next several years. In addition, Detroit Edison expects to make approximately \$6 million of capital improvements to the ash landfill in 2008.

## Gas Utility

**Contaminated Sites** – Prior to the construction of major interstate natural gas pipelines, gas for heating and other uses was manufactured locally from processes involving coal, coke or oil. Gas Utility owns, or previously owned, 15 former MGP sites. Investigations have revealed contamination related to the by-products of gas manufacturing at each site. In addition to the MGP sites, Gas Utility is also in the process of cleaning up other contaminated sites. Cleanup activities associated with these sites will be conducted over the next several years. As a result of these determinations, we have recorded liabilities of \$40 million and \$2 million for the MGP and other contaminated sites, respectively. It is estimated that Gas Utility may spend \$6 million in expenses related to cleanup costs in 2008.

A cost deferral and rate recovery mechanism was approved by the MPSC for investigation and remediation costs incurred at former MGP sites. After a study was completed in 1995, Gas Utility accrued an additional liability and a corresponding regulatory asset of \$35 million. During 2007, we spent approximately \$2 million investigating and remediating these former MGP sites. We accrued an additional \$1 million in remediation liabilities associated with former MGP holders to increase the reserve balance to \$40 million as of December 31, 2007.

Any significant change in assumptions, such as remediation techniques, nature and extent of contamination and regulatory requirements, could impact the estimate of remedial action costs for the sites and thereby affect our financial position and cash flows. However, we anticipate the cost deferral and rate recovery mechanism approved by the MPSC will prevent environmental costs from having a material adverse impact on our consolidated results of operations.

## Other

Our non-utility affiliates are subject to a number of environmental laws and regulations dealing with the protection of the environment from various pollutants. We are in the process of installing new environmental equipment at our coke battery facilities in Michigan. We expect the project to be substantially completed during 2009 at a cost of approximately \$15 million. Our non-utility affiliates are substantially in compliance with all environmental requirements.

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

## New Accounting Pronouncements

See Note 2 of the Notes to Consolidated Financial Statements.

## Fair Value Of Contracts

The accounting standards for determining whether a contract meets the criteria for derivative accounting are numerous and complex. Moreover, significant judgment is required to determine whether a contract requires derivative accounting, and similar contracts can sometimes be accounted for differently. If a contract is accounted for as a derivative instrument, it is recorded in the financial statements as "Assets or Liabilities from risk management and trading activities," at the fair value of the contract. The recorded fair value of the contract is then adjusted at each reporting date, in the Consolidated Statements of Operations, to reflect any change in the fair value of the contract, a practice known as mark-to-market (MTM) accounting. Changes in the fair value of a designated derivative that is highly effective as a cash flow hedge are recorded as a component of Accumulated other comprehensive income, net of taxes, until the hedged item affects income. These amounts are subsequently reclassified into earnings as a component of the value of the forecasted transaction, in the same period as the forecasted transaction affects earnings. The ineffective portion of the fair value changes is recognized in the Consolidated Statements of Operations immediately.

Fair value represents the amount at which willing parties would transact an arms-length transaction. To determine the fair value of contracts accounted for as derivative instruments, we use a combination of quoted market prices, broker quotes 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 include power, gas, certain coal, and oil forwards, futures, options and swaps, as well as foreign currency contracts. Items we do not generally account for as derivatives (and which are therefore excluded from the following tables) include gas inventory, gas storage and transportation arrangements, and gas and oil reserves.

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 by originating substantially hedged positions with wholesale energy marketers, producers, end users, 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.

- "Other" primarily represents derivative activity associated with our gas reserves and discontinued synfuel operations. A portion of the price risk associated with anticipated production from the Barnett gas reserves has been mitigated through 2010. Changes in the value of the hedges are recorded as "Assets or Liabilities from risk management and trading activities," with an offset in Other comprehensive income to the extent that the hedges are deemed effective. Oil-related derivative contracts were executed to economically hedge cash flow risks related to underlying, non-derivative synfuel related positions through 2007. The amounts shown in the following tables exclude the value of the underlying gas reserves and synfuel proceeds including changes therein.

### Roll-Forward of MTM Energy Contract Net Assets

The following tables provide details on changes in our MTM net asset (or liability) position during 2007:

<i>(in Millions)</i>	Proprietary Trading	Structured Contracts	Economic Hedges	Other	Total
MTM at December 31, 2006	\$ (9)	\$ (2)	\$ (36)	\$ (24)	\$ (71)
Reclassified to realized upon settlement	22	1	17	16	56
Changes in fair value recorded to income	4	(57)	23	(220) (1)	(250)
Amortization of option premiums	(10)	(2)	—	(101) (2)	(113)
Amounts recorded to unrealized income	16	(58)	40	(305)	(307)
Amounts recorded in Other comprehensive Income	—	—	—	(1)	(1)
Transfer of contracts	—	(323)	—	323	—
Option premiums paid and other	1	37	—	9	47
MTM at December 31, 2007	\$ 8	\$ (346)	\$ 4	\$ 2	\$ (332)

(1) Change in fair value of contracts in Unconventional Gas Production prior to the transfer to Energy Trading as a result of the Antrim sale.

(2) Realized synfuel option premiums by Power and Industrial Projects.

A substantial portion of the Company's price risk related to its Antrim shale gas exploration and production business had been mitigated by financial contracts that hedged our price risk exposure through 2013. These financial contracts were accounted for as cash flow hedges, with changes in estimated fair value of the contracts reflected in Other comprehensive income. Upon the sale of Antrim, the financial contracts no longer qualified as cash flow hedges. The contracts were retained and offsetting financial contracts were put into place to effectively settle these positions.

The following table provides a current and noncurrent analysis of "Assets and Liabilities from risk management and trading activities," as reflected on the Consolidated Statements of Financial Position as of December 31, 2007. Amounts that relate to contracts that become due within twelve months are classified as current and all remaining amounts are classified as noncurrent.

<i>(in Millions)</i>	Proprietary Trading	Structured Contracts	Economic Hedges	Eliminations	Other	Assets (Liabilities)
Current assets	\$ 35	\$ 135	\$ 29	\$ (9)	\$ 5	\$ 195
Noncurrent assets	9	194	8	(4)	—	207
Total MTM assets	44	329	37	(13)	5	402
Current liabilities	(34)	(234)	(23)	9	—	(282)
Noncurrent liabilities	(2)	(441)	(10)	4	(3)	(452)
Total MTM liabilities	(36)	(675)	(33)	13	(3)	(734)
Total MTM net assets (liabilities)	\$ 8	\$ (346)	\$ 4	\$ —	\$ 2	\$ (332)

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

We manage our MTM risk on a portfolio basis based upon the delivery period of our contracts and the individual components of the risks within each contract. Accordingly, we record and manage the energy purchase and sale obligations under our contracts in separate components based on the commodity (e.g. electricity or gas), the product (e.g. electricity for delivery during peak or off-peak hours), the delivery location (e.g. by region), the risk profile (e.g. forward or option), and the delivery period (e.g. by month and year).

We determine the MTM adjustment for our derivative contracts from a combination of active quotes, published indexes and mathematical valuation models. We generally derive the pricing for our contracts from active quotes or external resources. Actively quoted indexes include exchange-traded positions such as the New York Mercantile Exchange and the Intercontinental Exchange, and over-the-counter positions for which broker quotes are available. For periods in which external market data is not readily observable, we estimate value using mathematical valuation models. We periodically update our policy and valuation methodologies for changes in market liquidity and other assumptions which may impact the estimated fair value of our derivative contracts. During 2007, we performed an analysis of the energy markets and its participants, including an evaluation of liquidity. As a result, we revised our policy and valuation estimates for the portions of our contracts that extend beyond the actively traded reporting period. Accordingly, our power and natural gas contracts are marked through 2011 and 2013, respectively. The majority of our long-dated power contracts relate to retail or structured transactions, which require the use of internal models to estimate fair value.

As a result of adherence to generally accepted accounting principles, the tables above do not include the expected earnings impacts of certain non-derivative gas storage and power contracts. Consequently, gains and losses from these positions may not match with the related physical and financial hedging instruments in some reporting periods, resulting in volatility in DTE Energy's reported period-by-period earnings; however, the financial impact of this timing difference will reverse at the time of physical delivery and/or settlement.

The table below shows the maturity of our MTM positions:

(in Millions)

Source of Fair Value	2008	2009	2010	2011 and Beyond	Total Fair Value
Proprietary Trading	\$ 1	\$ 7	\$ —	\$ —	\$ 8
Structured Contracts	(99)	(78)	(52)	(117)	(346)
Economic Hedges	6	—	(2)	—	4
Other	5	(2)	(1)	—	2
<b>Total</b>	<b>\$ (87)</b>	<b>\$ (73)</b>	<b>\$ (55)</b>	<b>\$ (117)</b>	<b>\$ (332)</b>

## Quantitative and Qualitative Disclosures About Market Risk

### Market Price Risk

DTE Energy has commodity price risk in both utility and non-utility businesses arising from market price fluctuations.

The Electric and Gas utility businesses have risks in conjunction with the anticipated purchases of coal, natural gas, uranium, electricity, and base metals to meet their service obligations. Further, changes in the price of electricity can impact the level of exposure of Customer Choice programs and uncollectible expenses at the Electric Utility. In addition, changes in the price of natural gas can impact the valuation of lost gas, storage sales revenue and uncollectible expenses at the Gas Utility.

To limit our exposure to commodity price fluctuations, the utility businesses have applied various approaches including forward energy, capacity, storage and futures contracts, as well as regulatory rate-recovery mechanisms. Regulatory rate-recovery occurs in the form of PSCR and GCR mechanisms (see Note 1 of the Notes to Consolidated Financial Statements) and a tracking mechanism to mitigate some losses from customer migration due to electric Customer Choice programs.

Our Power and Industrial Projects segment is subject to crude oil, electricity, natural gas and coal based product price risk. As previously discussed, production tax credits generated by DTE Energy's coke battery and landfill gas recovery operations are subject to phase-out if domestic crude oil prices reach certain levels. The benefits associated with tax credits may be subject to changes in federal tax law. See Note 15 of the Notes to Consolidated Financial Statements. To manage this exposure, we use forward energy, capacity and futures contracts.

Our Unconventional Gas Production business segment has exposure to natural gas and, to a lesser extent, crude oil price fluctuations. These commodity price fluctuations can impact both current year earnings and reserve valuations. To manage this exposure we use forward energy and futures contracts.

Our Energy Trading business segment has exposure to electricity, natural gas, crude oil, heating oil, and foreign currency price fluctuations. These risks are managed through its energy marketing and trading operations through the use of forward energy, capacity, storage, options and futures contracts, within pre-determined risk parameters.

Our Coal and Gas Midstream business segment has exposure to natural gas and coal price fluctuations. These coal price risks are managed primarily through its coal transportation and marketing operations through the use of forward coal and futures contracts. The Gas Midstream business unit manages its exposure through the sale of long-term storage and transportation contracts.

## Credit Risk

### Bankruptcies

We purchase and sell electricity, gas, coal, coke and other energy products from and to numerous companies operating in the steel, automotive, energy, retail and other industries. Certain of our customers have filed for bankruptcy protection under Chapter 11 of the U.S. Bankruptcy Code. We regularly review contingent matters relating to these customers and our purchase and sale contracts and we record provisions for amounts considered at risk of probable loss. We believe our previously accrued amounts are adequate for probable loss. The final resolution of these matters is not expected to have a material effect on our financial statements.

### Other

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

### Energy Trading

We are exposed to credit risk through trading activities. Credit risk is the potential loss that may result if our trading counterparties fail to meet their contractual obligations. We utilize both external and internally generated credit assessments when determining the credit quality of our trading counterparties. The following table displays the credit quality of our trading counterparties as of December 31, 2007:

<i>(in Millions)</i>	Credit Exposure before Cash Collateral	Cash Collateral	Net Credit Exposure
Investment Grade (1)			
A- and Greater	\$ 612	\$ (100)	\$ 512
BBB+ and BBB	104	–	104
BBB-	46	–	46
Total Investment Grade	762	(100)	662
Non-investment grade (2)	38	(5)	33
Internally Rated – investment grade (3)	98	(1)	97
Internally Rated – non-investment grade (4)	10	(8)	2
<b>Total</b>	<b>\$ 908</b>	<b>\$ (114)</b>	<b>\$ 794</b>

(1) This category includes counterparties with minimum credit ratings of Baa3 assigned by Moody's Investor Service (Moody's) and BBB- assigned by Standard & Poor's Rating Group, a division of the McGraw-Hill Companies, Inc. (Standard & Poor's). The five largest counterparty exposures combined for this category represented approximately 34 percent 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 approximately three percent 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 approximately seven percent 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 approximately one percent of the total 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 may 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, 2007, we had a floating rate debt-to-total debt ratio of approximately 18% (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 January 2012. Additionally, we may enter into fair value currency hedges to mitigate changes in the value of contracts or loans.

## Summary of Sensitivity Analysis

We performed a sensitivity analysis on 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, 2007 by a hypothetical 10% and calculating the resulting change in the fair values.

The results of the sensitivity analysis calculations follow:

<i>(in Millions)</i>	Assuming a 10% increase in rates	Assuming a 10% decrease in rates	Change in the fair value of
<b>Activity</b>			
Coal Contracts	\$ (2)	\$ 2	Commodity contracts
Gas Contracts	\$ (13)	\$ 13	Commodity contracts
Power Contracts	\$ (13)	\$ 13	Commodity contracts
Interest Rate Risk	\$ (290)	\$ 315	Long-term debt
Foreign Currency Risk	\$ 1	\$ (1)	Forward contracts