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

Overview

DTE Energy is a diversified energy company with 2006 revenues in excess of $9 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 five energy-related non-utility segments with operations throughout the United States.

The following table summarizes our financial results:

(in millions, except Earnings per Share)	2006	2005	2004
Income from Continuing Operations	$ 437	$ 577	$ 464
Earnings per Diluted Share	$ 2.45	$ 3.28	$ 2.68
Net Income	$ 433	$ 537	$ 431
Earnings per Diluted share	$ 2.43	$ 3.05	$ 2.49

The decrease in 2006 net income is primarily due to the temporary idling of synfuel plants along with the associated impairments and reserves, and impairments within our Power and Industrial Projects segment. This decrease was partially offset by higher earnings at our electric utility, Detroit Edison, and Energy Trading segment mark-to-market losses in 2005 which did not recur in 2006.

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

- Effects of weather and collectibility of accounts receivable on utility operations;
- Impact of regulatory decisions on our utility operations;
- Investments in our Unconventional Gas Production business;
- Results in our Energy Trading business;
- Synfuel-related earnings and the impact of temporarily idling synfuel facilities in 2006; and
- Cost reduction efforts and required capital investment.

Utility Operations

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. During 2006, we experienced milder than normal weather conditions.

Additionally, we occasionally experience various types of storms that damage our electric distribution infrastructure resulting in power outages. Restoration and other costs associated with storm-related power outages lowered pretax earnings by $46 million in 2006, $82 million in 2005 and $48 million in 2004.

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

We have taken aggressive actions to reduce the level of past due receivables including, increased customer disconnections, contracting with collection agencies and working with the State of Michigan and others to increase the share of low-income funding allocated to our customers. In 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 bad debt expense, which is included within Operation and maintenance expense.

As a result of these factors, our allowance for doubtful accounts expense for the two utilities increased to $123 million in 2006 from $98 million in 2005 and from $105 million in 2004.

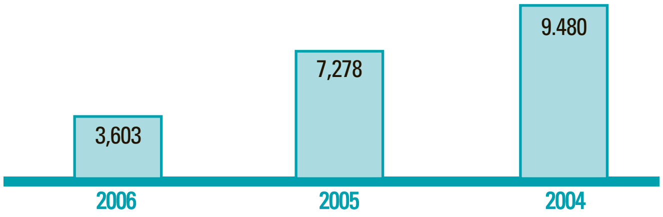
The April 2005 Michigan Public Service Commission (MPSC) gas rate order provided for an uncollectible true-up mechanism for MichCon. We filed the 2005 annual reconciliation, comparing our actual uncollectible expense to our designated revenue recovery of approximately $37 million on an annual basis. The MPSC approved the 2005 annual reconciliation on December 21, 2006 allowing MichCon to surcharge the $11 million excess beginning in January 2007.

We expect to file the 2006 annual reconciliation with the MPSC no later than March 31, 2007 comparing our actual 2006 uncollectible expense to our designated revenue recovery of approximately $37 million. Ninety percent of the difference for the year will be requested to be surcharged as part of the annual reconciliation proceeding before the MPSC. We have accrued $33 million under the 2006 uncollectible true-up mechanism.

Regulatory activity - In accordance with the MPSC's directive in Detroit Edison's November 2004 rate order, in March 2005, Detroit Edison filed a joint application and testimony in its 2004 Power Supply Cost Recovery (PSCR) Reconciliation Case and its 2004 Net Stranded Cost Recovery Case. In September 2006, the MPSC issued an order recognizing $19 million of 2004 net stranded costs that required Detroit Edison to write off $112 million of 2004 net stranded costs. The MPSC order resulted in a $39 million reduction in the 2004 PSCR over-collection by allowing Detroit Edison to retain the benefit of third party wholesale sales required to support the electric Customer Choice program and to offset the recognition of the $19 million of 2004 stranded costs. The MPSC order also resulted in reductions in accrued interest on the 2004 and 2005 PSCR amounts of $15 million. The MPSC directed Detroit Edison to include the remaining 2004 PSCR over-collection amount and related interest in the 2005 PSCR Reconciliation which is in an under-collected position. The order resulted in a reduction of pre-tax income of approximately $58 million.

The following graph depicts the total electric Customer Choice volumes for customers who have purchased power from an alternative electric supplier:

Electric Customer Choice Volumes
in MWh



In March 2006, the MPSC issued an order directing Detroit Edison to show cause by June 1, 2006 why its retail electric rates should not be reduced in 2007. The MPSC issued an order approving the settlement agreement in this proceeding on August 31, 2006. The order provided for an annualized rate reduction of $53 million for 2006, effective September 5, 2006. Beginning January 1, 2007, and continuing until the later of March 31, 2008 or 12 months from the filing date of Detroit Edison's next main rate case, rates will be reduced by an additional $26 million, for a total reduction of $79 million. Detroit Edison experienced a rate reduction of approximately $13 million in 2006 as a result of this order. The revenue reduction is net of the recovery of the amortization of the costs associated with the implementation of the Performance Excellence Process. The settlement agreement provides for some level of realignment of the existing rate structure by allocating a larger percentage share of the rate reduction to the commercial and industrial customer classes than to the residential customer classes.

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

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 are currently expanding the Fermi 2 spent fuel pool capacity to meet our storage requirements through 2009. 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, skill 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 from certain power generation assets, losses from our 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 are considering various actions including the sale, restructuring or recapitalization of various non-utility businesses which we expect may generate over $800 million in cash proceeds in 2007. We plan to continue to invest in focused areas that have the strongest opportunities.

The primary source of recent investment capital has been cash flow from the synfuel business. We have hedged a portion of the risk of an oil price-related phase-out of production tax credits in the synfuel business. We now anticipate approximately $900 million of synfuel-related cash impacts from 2007 through 2009, which consists of cash from operations and proceeds from option hedges, and approximately $500 million of tax credit carryforward utilization and other tax benefits that are expected to reduce future tax payments. Tax credit carryforward utilization in part could be extended past 2009, if taxable income is reduced from current forecasts.

Coal and Gas Midstream

We are continuing to build our capacity to transport greater amounts of western coal and to expand into coal terminals to allow for increased coal storage and blending. We are currently involved in a contract dispute with BNSF Railway Company that has been referred to arbitration. Under this contract, BNSF transports western coal east for Detroit Edison and the Coal Transportation and Marketing business. We have filed a breach of contract claim against BNSF for the failure to provide certain services that we believe are required by the contract. The arbitration hearing is scheduled for mid-2007. While we believe we will prevail on the merits in this matter, a negative decision with respect to the significant issues being heard in the arbitration could have an adverse effect on our ability to grow the Coal Transportation and Marketing business as currently contemplated.

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

Unconventional Gas Production

Current natural gas prices provide attractive opportunities for our Unconventional Gas Production business segment. We are an experienced operator with more than 15 years of experience in the Antrim shale in northern Michigan, and we continue to expand our operations in the Barnett shale basin in north Texas, where recent leasehold acquisitions have increased our total leasehold acreage to 89,808 acres (80,530 net of interest of others) after reduction by opportunistic sales of 11,193 acres.

We are exploring the sale of a portion of our Unconventional Gas Production assets which will allow us to monetize value from our more mature holdings, while retaining the ability to benefit from the upside of our earlier stage holdings.

Antrim shale - We intend to develop existing acreage using the latest vertical and horizontal drilling and fracture stimulation techniques. Our long-term fixed-price obligations for production of Antrim continue to expire in 2007. This will create opportunities to remarket Antrim production at significantly higher current market rates.

	2006	2005	2004
Michigan - Antrim Shale			
Net Producing Wells	1,700	1,630	1,523
Production Volume (Bcfe)	22	22	23
Proved Reserves (Bcfe)	442	338	335
Net Developed Acreage	228,232	217,643	213,959
Net Undeveloped Acreage	66,184	73,056	79,025
Capital Expenditures (in Millions)	$ 49	$ 37	$ 22
Future Undiscounted Net Cash Flows (in Millions) (1)	$ 1,636	$ 1,307	$ 760
Average gas price with hedges (per Mcf)	$ 3.41	$ 3.10	$ 3.10
Average gas price without hedges (per Mcf) (2)	$ 6.61	$ 7.73	$ 5.57

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

(2) The gas produced in the Antrim shale is subject to hedges that began to expire in 2006. For 2007, we anticipate remarketing an additional 1.8 Bcf.

Barnett Shale - We anticipate significant opportunities in our existing Barnett shale acreage and expect continued extension of producing areas within the Fort Worth Basin. We are currently in the test and development phase for unproved and recently acquired Barnett shale acreage.

	2006	2005	2004
Texas - Barnett Shale			
Net Producing Wells	110	55	1
Production Volume (Bcfe)	4	1	–
Proved Reserves (Bcfe)	174	59	8
Net Developed Acreage	16,045	14,637	316
Net Undeveloped Acreage	64,485	61,627	48,541
Capital Expenditures (in Millions)	$ 137	$ 107	$ 16
Future Undiscounted Net Cash Flows (in Millions) (1)	$ 472	$ 127	$ 7
Average gas price (per Mcf)	$ 5.66	$ 9.01	$ 5.70

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

Current natural gas prices and successes within the Barnett shale are resulting in more capital being invested into the region. The competition for opportunities and goods and services may result in increased operating costs. However, our experience in the Antrim shale and our experienced Barnett shale personnel provide an advantage in addressing potential cost increases. We invested $186 million in 2006 and expect to invest a combined amount of approximately $150 million to $170 million in our unconventional gas business in 2007.

As a component of our risk management strategy for our Barnett shale reserves, we hedged a portion of our proved developed producing reserves to secure an attractive investment return. As of December 31, 2006, we entered into a series of cash flow hedges for 4.7 Bcf of anticipated gas production through 2010 at an average price of $8.08 per Mcf.

Power and Industrial Projects

Power and Industrial Projects is comprised primarily of projects that deliver utility-type services to industrial, commercial and institutional customers, and biomass energy projects. We provide utility-type services using project assets usually located on 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. We own and operate three gas-fired peaking electric generating plants and a biomass-fired electric generating plant and operate one additional gas-fired power plant under contract. Additionally, we own a gas-fired peaking electric generating plant that was taken out of service in September 2006. We develop, own and operate landfill gas recovery systems throughout the United States. We produce coke from two coke batteries. The production of coke from our coke batteries generates production tax credits (assuming no phase-out).

We are exploring the combination of a sale of an equity interest in, and recapitalization of, some of the assets of the Power and Industrial Projects business, including the sale or restructuring of the power generation assets. In February 2007, we entered into an agreement to sell our Georgetown peaking electric generating facility. The sale is subject to receipt of regulatory approval and is expected to close in the second half of 2007.

Energy Trading

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 capacity positions. Most financial instruments are deemed derivatives, whereas the gas inventory, pipelines and storage assets are not derivatives. As a result, this segment may experience 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 will reverse in subsequent periods when transactions are settled.

During 2005, our earnings were negatively impacted by the economically favorable decision to delay previously planned withdrawals from gas storage due to a decrease in the current price for natural gas and an increase in the forward price for natural gas. In addition, we entered into forward power contracts to economically hedge certain physical and capacity power contracts. The financial impacts of these timing differences have begun to reverse and have favorably impacted results during 2006. We are exploring strategic options for the energy trading business.

Synthetic Fuel

Synthetic Fuel Operations

Synfuel plants chemically change coal and waste coal into a synthetic fuel as determined under the Internal Revenue Code. Production tax credits are provided for the production and sale of solid synthetic fuel produced from coal and are available through December 31, 2007. The synthetic fuel plants generate operating losses which we expect to be 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.

We are the operator of nine synthetic fuel production facilities throughout the United States. On May 12, 2006, we idled production at all nine of the synthetic fuel facilities. The decision to idle synfuel production was driven by the level and volatility of oil prices at that time. During the idle period, we took various steps to reduce our oil price exposure, including renegotiation of a significant number of commercial agreements. Beginning September 5, 2006 through October 4, 2006, we resumed production at each of the nine synfuel facilities due to these amended commercial agreements and declines in the level of oil prices.

Recognition of Synfuel Gains

To optimize income and cash flow from the synfuel operations, we sold interests in all nine of the facilities, representing 91% of the total production capacity as of December 31, 2006. Proceeds from the sales are contingent upon production levels and the value of credits generated. Gains from the sale of an interest in a synfuel project are recognized when there is persuasive evidence that the sales proceeds have become fixed or determinable, the probability of refund is considered remote and collectibility is assured. In substance, we receive synfuel gains and reduced operating losses in exchange for tax credits associated with the projects sold.

The gain from the sale of synfuel facilities is generally comprised of fixed and variable components. The fixed component represents note payments, is not subject to refund, and is recognized as a gain when earned and collectibility is assured. The variable component is based on an estimate of tax credits allocated to our partners and is subject to refund based on the annual oil price phase-out. The variable component is recognized as a gain only when the probability of refund is considered remote and collectibility is assured. Additionally, our partners reimburse us (through the project entity) for the operating losses of the synfuel facilities, referred to as capital contributions. In the event that the tax credit is phased out, we are contractually obligated to refund an amount equal to all or a portion of the operating losses funded by our partners. To assess the probability and estimate the amount of refund, we use valuation and analysis models that calculate the probability of the Reference Price of oil for the year being within or exceeding the phase-out range. Due to changes in the agreements with certain of our synfuel partners and the exercise of existing rights by other synfuels partners, a higher percentage of the payments in 2006 were variable payments. As a result, a larger portion of the 2006 synfuel payments are subject to refund as a result of the phase-out; and therefore reduced the gain associated with the payments.

Crude Oil Prices

The Reference Price of a barrel of oil is an estimate by the IRS of the annual average wellhead price per barrel for domestic crude oil. The value of the production tax credit in a given year is reduced if the Reference Price of oil over the year exceeds a threshold price and is eliminated entirely if that same Reference Price exceeds a phase-out price. During 2006, the annual average wellhead price is projected to be approximately $6 lower than the New York Mercantile Exchange (NYMEX) price for light, sweet crude oil. The actual or estimated Reference Price and beginning and ending phase-out prices per barrel of oil for 2005 through 2007 are as follows:

	Reference Price	Beginning Phase-Out Price	Ending Phase-Out Price
2005 (actual)	$50.26	$53.20	$66.79
2006 (estimated)	$60	$55	$69
2007 (estimated)	Not Available	$56	$70

The NYMEX daily closing price of a barrel of oil for 2006 averaged approximately $66, which is approximately equal to a Reference Price of $60 per barrel, which we estimate to be within the phase-out range. The actual tax credit phase-out for 2006 will not be certain until the Reference Price is published by the IRS in April 2007. There is a risk of at least a partial phase-out of the production tax credits in 2007, which could adversely impact our results of operations, cash flow, and financial condition.

Hedging of Synfuel Cash Flows

As discussed in Note 2 of the Notes to Consolidated Financial Statements, we have entered into derivative and other contracts to economically hedge a portion of our synfuel cash flow exposure to the risk of oil prices increasing. The derivative contracts are marked-to-market with changes in fair value recorded as an adjustment to synfuel gains. To manage our exposure in 2007 to the risk of an increase in oil prices that could substantially reduce or eliminate synfuel sales proceeds, we entered into a series of derivative contracts covering a specified number of barrels of oil. The derivative contracts involve purchased and written call options that provide for net cash settlement at expiration based on the full years' 2007 average NYMEX trading prices for light, sweet crude oil in relation to the strike prices of each option. If the average NYMEX prices of oil in 2007 are less than approximately $60 per barrel, the derivatives will yield no payment. If the average NYMEX prices of oil exceed approximately $60 per barrel, the derivatives will yield a payment equal to the excess of the average NYMEX price over these initial strike prices, multiplied by the number of barrels covered, up to a maximum price of approximately $76 per barrel. These contracts are based on various terms to take advantage of increases in oil prices. We recorded pretax mark-to-market gains of $60 million during 2006 and $47 million in 2005, and a $12 million loss in 2004. The fair value changes are recorded as adjustments to the gain from selling interests in synfuel facilities and are included in the Asset gains and losses, reserves and impairments, net line item in the Consolidated Statement of Operations. We paid approximately $50 million for 2006 hedges, for which we received payments of approximately $156 million upon settlement of these hedges in January 2007. Through December 31, 2006, we paid approximately $103 million for 2007 hedges which will provide protection for a significant portion of our cash flows related to the synfuel production during 2007. As part of our synfuel-related risk management strategy, we continue to evaluate alternatives available to mitigate unhedged exposure to oil price volatility. As our risk management position changes due to market volatility, we may adjust our hedging strategy in response to changing conditions.

Risks and Exposures

Since there was the likelihood that the Reference Price for a barrel of oil would remain above the threshold at which synfuel-related production tax credits began to phase-out, we deferred gain recognition associated with variable and certain fixed note payments in 2006 until the end of the year when the probability of refund was remote and collectibility was assured. We deferred all variable gains for the first three quarters of 2006 and 2005. We recognized $43 million of fixed gains and $14 million of variable gains in 2006, compared to fixed gains of $132 million and variable gains of $187 million in 2005. All or a portion of the deferred gains will be recognized when and if the gain recognition criteria is met. Additionally, we may establish reserves for potential refunds of amounts related to partners' capital contributions associated with operating losses allocated to their account. As previously discussed, in the event of a tax credit phase-out, we are contractually obligated to refund to our partners all or a portion of the operating losses funded by our partners.

In 2006, we recorded reserves and impairments of $157 million, consisting of a $79 million reserve for capital contributions related to operating losses and an impairment of $78 million for synfuel-related fixed assets and inventory. The fixed asset impairment was partially offset by $70 million included in the Minority Interest line on our Consolidated Statement of Operations, representing our partners' share of the asset write down.

Cash from synfuel activity is at risk of a phase-out of the production tax credits. We expect approximately $900 million of synfuel-related cash impacts from 2007 through 2009, which consists of cash from operations, asset sales and proceeds from option hedges, and approximately $500 million of tax credit carryforward utilization and other tax benefits that are expected to reduce future tax payments. The expected cash flow of approximately $900 million is economically hedged against the movement in oil prices. In addition, a goodwill write-off of up to $4 million will likely be required in 2007 due to the production tax credit phase-out, the inability to generate new production tax credits after 2007 and the resulting discontinuance of synfuel production. We have fixed note receivables associated with the sales of interests in the synfuel facilities. A partial or full phase-out of production tax credits could adversely affect the collectibility of our receivables. The cash flow impact would likely reduce our ability to execute our investment and growth strategy.

OPERATING SYSTEM AND PERFORMANCE EXCELLENCE PROCESS

We continuously review and adjust our cost structure and seek improvements in our processes. Beginning in 2002, we adopted the DTE Energy Operating System, which is the application of tools and operating practices that have resulted in operating efficiencies, inventory reductions and improvements in technology systems, among other enhancements. Some of these cost reductions may be returned to our customers in the form of lower PSCR charges and the remaining amounts may impact our profitability.

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

The process is rigorous and challenging and seeks to yield sustainable performance to our customers and shareholders. We have identified the Performance Excellence Process as critical to our long-term growth strategy. Detroit Edison's costs to achieve (CTA), consisting of project management, consultant support and employee severance, is estimated to total between $160 million and $190 million. MichCon's CTA is estimated to total between $55 million and $60 million. We estimate savings of approximately $45 million in operation and maintenance expenses and capital costs were realized in 2006. In 2006, we recorded CTA of approximately $134 million. CTA in 2006 exceeded our savings, but we expect to realize sustained net cost savings beginning 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 will begin 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. MichCon cannot defer CTA costs at this time because a recovery mechanism has not been established.

CAPITAL INVESTMENT

We anticipate significant capital investment across all of our business segments. Most of our capital expenditures will be concentrated within our utility segments. Our electric utility currently expects to invest approximately $4.3 billion, including increased environmental requirements and reliability enhancement projects through 2011. Our gas utility 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.

In 2005, we launched the first phase of our Enterprise Business Systems project, an enterprise resource planning system initiative to improve existing processes and to implement new core information systems. Through December 2006, we have spent approximately $330 million on this project and we anticipate spending an additional $45 million to $70 million over the next year as the remaining system elements are developed and implemented.

In the future, we may build a new base-load coal or nuclear electric generating plant. The last base-load plant constructed within our electric utility service territory was approximately twenty years ago.

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. Due to the enactment of the Energy Policy Act of 2005 and the repeal of the Public Utility Holding Company Act of 1935, there are fewer barriers to mergers and acquisitions of utility companies at the federal level. However, the expected industry consolidation, resulting in the creation of large regional utility providers, has been recently impacted by actions of regulators in certain states affected by the proposed transactions.

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 $900 million of synfuel-related cash impacts from 2007 through 2009, which consists of cash from operations and proceeds from option hedges, and approximately $500 million of tax credit carryforward utilization and other tax benefits that are expected to reduce future tax payments. The redeployment of this cash represents a unique opportunity to increase shareholder value and strengthen our balance sheet. We expect to use any such cash and the potential cash from monetization of certain of our non-utility assets and operations to reduce debt and repurchase common stock, and to continue to pursue growth investments that meet our strict risk-return and value creation criteria. Our objectives for cash redeployment are to 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.

Results of Operations

Net income in 2006 was $433 million, or $2.43 per diluted share, compared to net income of $537 million, or $3.05 per diluted share in 2005 and net income of $431 million, or $2.49 per diluted share in 2004. Excluding discontinued operations and the cumulative effect of accounting changes, our income from continuing operations in 2006 was $437 million, or $2.45 per diluted share, compared to income of $577 million, or $3.28 per diluted share in 2005 and income of $464 million, or $2.68 per diluted share in 2004. The following sections provide a detailed discussion of our segments' operating performance and future outlook.

Segments realigned – In the third quarter of 2006, we realigned the non-utility segment Power and Industrial Projects business unit to separately present the Synthetic Fuel business. The impending expiration of synfuel tax credits as of December 31, 2007, combined with the sustained volatility of oil prices, increased management focus on synfuels, thereby requiring a separate business segment. In the fourth quarter of 2006, we separated the Fuel Transportation and Marketing segment into Coal and Gas Midstream, and Energy Trading corresponding to additional management focus on the results of these non-utility segments. 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
  - *Synthetic Fuel*, consisting of the operations of nine synfuel plants.
- *Corporate & Other*, primarily consisting of corporate staff functions and certain energy technology investments.

(in Millions, except per share data)	2006	2005	2004
Net Income by Segment			
Electric Utility	$ 325	$ 277	$ 150
Gas Utility	50	37	20
Non-utility Operations:			
Coal and Gas Midstream	50	45	33
Unconventional Gas Production	9	4	6
Power and Industrial Projects	(80)	4	(17)
Energy Trading	96	(43)	85
Synthetic Fuel	48	305	199
Corporate & Other	(61)	(52)	(12)
Income (Loss) from Continuing Operations:			
Utility	375	314	170
Non-utility	123	315	306
Corporate & Other	(61)	(52)	(12)
	437	577	464
Discontinued Operations	(5)	(37)	(33)
Cumulative Effect of Accounting Changes	1	(3)	-
Net Income	$ 433	$ 537	$ 431
Diluted Earnings (Loss) Per Share			
Total Utility	$ 2.10	$ 1.78	$ .98
Non-utility Operations	.69	1.79	1.77
Corporate & Other	(.34)	(.29)	(.07)
Income from Continuing Operations	2.45	3.28	2.68
Discontinued Operations	(.03)	(.21)	(.19)
Cumulative Effect of Accounting Changes	.01	(.02)	-
Net Income	$ 2.43	$ 3.05	$ 2.49

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

Electric Utility

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

Factors impacting income: Our net income increased $48 million and $127 million in 2006 and 2005, respectively. These results primarily reflect higher gross margins, partially offset by increased depreciation and amortization expenses. Additionally, 2005 results were affected by higher rates due to the November 2004 MPSC final rate order, return of customers from the electric Customer Choice program, warmer weather and lower operations and maintenance expenses, partially offset by a portion of higher fuel and purchased power costs, which were unrecoverable as a result of residential rate caps (which expired January 1, 2006), and increased depreciation and amortization expenses.

(in Millions)	2006	2005	2004
Operating Revenues	$ 4,737	$ 4,462	$ 3,568
Fuel and Purchased Power	1,566	1,590	885
Gross Margin	3,171	2,872	2,683
Operation and Maintenance	1,336	1,308	1,395
Depreciation and Amortization	809	640	523
Taxes Other Than Income	252	241	249
Asset (Gains) and Losses, Net	(6)	(26)	(1)
Operating Income	780	709	517
Other (Income) and Deductions	294	283	303
Income Tax Provision	161	149	64
Net Income	$ 325	$ 277	$ 150
Operating Income as a Percent of Operating Revenues	16 %	16 %	14 %

Gross margin increased $299 million during 2006 and $189 million in 2005. 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. The increase in 2005 was due to higher demand resulting from warmer weather and increased rates due to the November 2004 MPSC final rate order, partially offset by unrecovered power supply costs as a result of residential rate caps (which expired January 1, 2006) and a poor Michigan economy. Gross margin was favorably impacted by decreased electric Customer Choice penetration, whereby we lost 6% of retail sales to electric Customer Choice customers in 2006 and 12% of such sales during 2005 as retail customers migrated back to us as their electric generation provider rather than remaining with alternative suppliers. Pursuant to the MPSC final rate order, transmission expense, previously recorded in operation and maintenance expenses in 2004, is now reflected in purchased power expenses. The PSCR mechanism provides related revenues for the transmission expense.

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

(in Millions)	2006	2005
Increase (Decrease) in Gross Margin Components Compared to Prior Year		
Weather-related margin impacts	$ (81)	$ 166
Removal of residential rate caps effective January 1, 2006	186	-
Return of customers from electric Customer Choice	156	79
Service territory economic performance	(16)	(23)
Impact of MPSC 2004 rate orders	26	116
Unrecovered power supply costs - residential customers	-	(73)
Transmission charges	-	(93)
Other, net	28	17
Increase in gross margin performance	$ 299	$ 189

(in Thousands of MWh)	2006		2005		2004	
Power Generated and Purchased						
Power Plant Generation						
Fossil	39,686	70 %	40,756	73 %	39,432	75 %
Nuclear	7,477	13	8,754	16	8,440	16
	47,163	83	49,510	89	47,872	91
Purchased Power	9,861	17	6,378	11	4,650	9
System Output	57,024	100 %	55,888	100 %	52,522	100 %
Less Line Loss and Internal Use	(3,603)		(3,205)		(3,574)	
Net System Output	53,421		52,683		48,948	
Average Unit Cost ($/MWh)						
Generation (1)	$ 15.61		$ 15.47		$ 12.98	
Purchased Power (2)	$ 53.71		$ 89.37		$ 37.06	
Overall Average Unit Cost	$ 22.20		$ 23.90		$ 15.11	

(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)	2006	2005	2004
Electric Sales			
Residential	15,769	16,812	15,081
Commercial	17,948	15,618	13,425
Industrial	13,235	12,317	11,472
Wholesale	2,826	2,329	2,197
Other	402	390	401
	50,180	47,466	42,576
Interconnection sales (1)	3,241	5,217	6,372
Total Electric Sales	53,421	52,683	48,948
Electric Deliveries			
Retail and Wholesale	50,180	47,466	42,576
Electric Customer Choice	2,694	6,760	9,245
Electric Customer Choice-Self Generators (2)	909	518	595
Total Electric Sales and Deliveries	53,783	54,744	52,416

(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 $28 million in 2006 and decreased $87 million in 2005. The 2006 increase was primarily due to increased distribution system maintenance of $35 million and increased plant outages of $33 million which was partially offset by $36 million of lower storm expenses. Pursuant to MPSC authorization, Detroit Edison deferred approximately $102 million of CTA in 2006. The comparability of 2005 to 2004 is affected by the November 2004 MPSC final rate order which required transmission and Midwest Independent System Operator (MISO) expenses to be included in purchased power expense with related revenues to be recorded through the PSCR mechanism. Additionally, the DTE Energy parent company no longer allocated merger-related interest as a result of the November 2004 MPSC final rate order, which was partially offset by higher 2005 storm expenses.

Depreciation and amortization expense increased $169 million and $117 million in 2006 and 2005, respectively. 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. We also had increased amortization of regulatory assets of $19 million related to electric Customer Choice and

$8 million related to our securitized assets. The 2005 increase reflects the income effect of recording regulatory assets in 2004, which lowered depreciation and amortization expenses. The regulatory asset deferrals totaled $46 million in 2005 and $107 million in 2004. Additionally, higher 2005 sales volumes compared to 2004 resulted in greater amortization of regulatory assets.

Asset (gains) and losses, net decreased $20 million in 2006 and increased $25 million in 2005 primarily as a result of our 2005 sale of land near our headquarters in Detroit, Michigan.

Other income and deductions expense increased $11 million in 2006 and decreased $20 million in 2005. The 2006 increase is attributable to higher interest expense due to increased long-term debt. The 2005 decrease is due primarily to lower interest expense as a result of lower interest rates and a favorable adjustment related to tax audit settlements.

Outlook – We continue to improve the operating performance of Detroit Edison. During the past year, we have resolved a portion of our regulatory issues and continue to pursue additional regulatory and/or legislative solutions for structural problems within the Michigan market structure, primarily electric Customer Choice and the need to adjust rates for each customer class to reflect the full cost of service.

Concurrently, we will move forward in our efforts to continue to improve performance. 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. Should we be able to recover these costs in future rate cases, we may experience a growth in earnings.

Additionally, our service territory may require additional generation capacity. A new base-load generating plant has not been built within the State of Michigan in the last 20 years. Should our regulatory environment be conducive to such a significant capital expenditure, we may build or expand a new base load coal or nuclear facility. While we have not decided on construction of a new base-load nuclear facility, 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 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; and
- levels of customer participation in the electric Customer Choice program.

We expect cash flows and operating performance will continue to be at risk due to the electric Customer Choice program until the issues associated with this program are adequately addressed. We will accrue as regulatory assets any future unrecovered generation-related fixed costs (stranded costs) due to electric Customer Choice that we believe are recoverable under Michigan legislation and MPSC orders. We cannot predict the outcome of these matters. See Note 6 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.

We continue to review the energy plan and 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 Fuel Gas Company (Citizens), natural gas utilities subject to regulation by the MPSC. MichCon is engaged in the purchase, storage, transmission, distribution and sale of natural gas to approximately 1.3 million residential, commercial and industrial customers in the State of Michigan. MichCon also has subsidiaries involved in the gathering and transmission of natural gas in northern Michigan. MichCon operates one of the largest natural gas distribution and transmission systems in the United States. Citizens distributes natural gas in Adrian, Michigan to approximately 17,000 customers.

Factors impacting income: Gas Utility's net income increased $13 million in 2006 and increased $17 million in 2005. The variances were primarily attributable to increased rates and the impacts in 2005 of the MPSC's April 2005 gas cost recovery and gas rate orders and the effect of milder weather in 2006.

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

(in Millions)	2006	2005	2004
Operating Revenues	$ 1,849	$ 2,138	$ 1,682
Cost of Gas	1,157	1,490	1,071
Gross Margin	692	648	611
Operation and Maintenance	431	424	403
Depreciation and Amortization	94	95	103
Taxes Other Than Income	53	43	49
Asset (Gains) and Losses, Net	-	4	(3)
Operating Income	114	82	59
Other (Income) and Deductions	53	47	48
Income Tax Provision (Benefit)	11	(2)	(9)
Net Income	$ 50	$ 37	$ 20
Operating Income as a Percent of Operating Revenues	6 %	4 %	4%

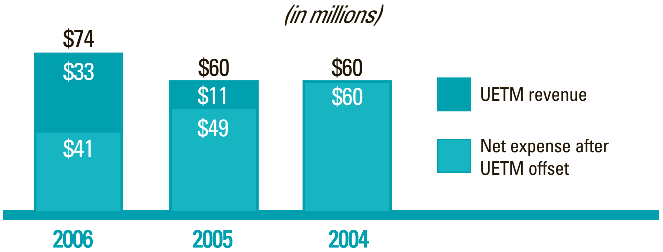
Gross margin increased $44 million and $37 million in 2006 and 2005, respectively. Gross margins were favorably affected by higher base rate revenues of $15 million and $42 million in 2006 and 2005, respectively. Revenue associated with the uncollectible expense tracking mechanism authorized by the MPSC in the April 2005 gas rate order, increased $22 million and $11 million in 2006 and 2005, respectively. 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 Gas Cost Recovery (GCR) reconciliation case that disallowed $26 million representing unbilled revenues at December 2001.

	2006	2005	2004
Gas Markets *(in Millions)*			
Gas sales	$ 1,541	$ 1,860	$ 1,435
End user transportation	135	134	119
	1,676	1,994	1,554
Intermediate transportation	69	58	56
Other	104	86	72
	$ 1,849	$ 2,138	$ 1,682
Gas Markets *(in Bcf)*			
Gas sales	138	168	173
End user transportation	136	157	145
	274	325	318
Intermediate transportation	373	432	536
	647	757	854

The 2005 final rate order provided revenue for an uncollectible expense true-up mechanism (UETM) to mitigate the effect of increasing uncollectible expense. The revenue recorded related to the UETM was $33 million for 2006 and $11 million for 2005.

Uncollectible Accounts Expense

(in millions)



Operation and maintenance expense increased $7 million and $21 million in 2006 and 2005, respectively. The 2006 increase is due to a $14 million increase in uncollectible accounts receivable expense, reflecting higher past due amounts attributable to an increase in gas prices, continued weak economic conditions, and inadequate government-sponsored assistance for low-income customers. In 2006, we recorded $24 million in implementation costs associated with our Performance Excellence Process and we recognized $9 million of lower injuries and damages expenses and lower labor and employee incentives. The comparability of 2006 to 2005 and the comparability of 2005 to 2004 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 final 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 increased $4 million and decreased $7 million in 2006 and 2005, respectively. The 2006 change was due to a $3 million gain on the sale of investment rights related to storage field construction which was offset by a $3 million loss due to a reduction to MichCon's 2004 GCR underrecovery related to the accounting treatment of the injected base gas remaining in the New Haven storage field when it was sold in early 2004. The $7 million decline in 2005 was primarily the result of a write-off of certain computer equipment and related depreciation resulting from the April 2005 final rate order.

Income tax provision increased by $13 million in 2006 and income tax benefit decreased $7 million in 2005 primarily due to variations in pre-tax earnings.

Outlook – Operating results are expected to vary due to regulatory proceedings, weather, changes in economic conditions, customer conservation and process improvements. Higher gas prices and economic conditions have resulted in continued pressure on receivables and working capital requirements that are partially mitigated by the GCR mechanism. In the April 2005 final gas rate order, the MPSC adopted MichCon's proposed tracking mechanism for uncollectible accounts receivable. Each year, MichCon will file an application comparing its actual uncollectible expense for the prior calendar year to its designated revenue recovery of approximately $37 million. Ninety percent of the difference will be refunded or surcharged after an annual reconciliation proceeding before the MPSC.

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.

NON-UTILITY OPERATIONS

Coal and Gas Midstream

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

Coal Transportation and Marketing provides fuel, transportation and rail equipment management services. We specialize in minimizing fuel costs and maximizing reliability of supply for energy-intensive customers. Additionally, we participate in coal 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.

Pipelines, Processing and Storage owns a partnership interest in an interstate transmission pipeline, six 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.

Factors impacting income: Net income increased $5 million and $12 million in 2006 and 2005, respectively.

(in Millions)	2006	2005	2004
Operating Revenues	$ 707	$ 707	$ 589
Operation and Maintenance	628	653	542
Depreciation and Amortization	4	3	3
Taxes Other Than Income	5	4	4
Operating Income	70	47	40
Other (Income) and Deductions	(8)	(20)	(12)
Income Tax Provision	28	22	19
Net Income	$ 50	$ 45	$ 33

Operating revenues remained the same in 2006 and increased $118 million in 2005. 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. During 2005, our Coal Transportation and Marketing business experienced higher throughput volumes and increased prices for coal.

Operation and maintenance expense decreased $25 million in 2006 and increased $111 million in 2005. The 2006 decrease was due to lower synfuel related volumes and decreased expenses at our Coal Transportation and Marketing business due to decreased marketing volume. During 2005, our Coal Transportation and Marketing business experienced higher throughput volumes and increased prices for coal.

Other income and deductions decreased $12 million in 2006 and increased $8 million in 2005. The 2006 decrease is primarily attributed to higher interest expense as a result of our storage expansion construction.

Income tax provision increased $6 million for 2006 and increased $3 million in 2005 reflecting variations in pre-tax income.

Outlook – 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. However, a portion of our Coal Transportation and Marketing revenues and net income are dependent upon our Synfuel operations and were adversely impacted by the temporary idling of the synfuel facilities in 2006. Coal Transportation and Marketing is involved in a contract dispute with BNSF Railway Company that has been referred to arbitration. See Note 15 of the Notes to Consolidated Financial Statements.

Our Pipeline, Processing and Storage business will continue its steady growth plan. In April 2006, Pipelines, Processing and Storage placed into service over 14 Bcf of storage capacity at an existing Michigan storage field and plans to file a MPSC application early in 2007 for a new gas storage reservoir which will increase its overall working gas storage capacity by 8.0 Bcf to a total of 74 Bcf. In December 2006, Washington 28 filed an application with the MPSC requesting an increase in its working gas storage capacity to 16.0 Bcf. Vector Pipeline has secured long-term market commitments to support an expansion project, for approximately 200 MMcf per day, with a projected in-service date of November 2007. Vector Pipeline received Federal Energy Regulatory Commission (FERC) approval for this expansion in October 2006. Pipeline, Processing and Storage has a 26.25% ownership interest in Millennium Pipeline which received FERC approval for construction and operation in December 2006. Millennium Pipeline is scheduled to be in service in late 2008. In October 2006, we purchased the lessor interest in the 66 Bcf Washington 10 gas storage field. Prior to the purchase, we leased the storage rights and lease obligations were recorded as operating leases. We plan to expand existing assets and develop new assets which are typically supported with long-term customer commitments.

Unconventional Gas Production

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

Factors impacting income: Net income increased $5 million in 2006 and decreased $2 million in 2005. 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. The decline in 2005 was due to higher operating and Michigan severance tax expenses.

(in Millions)	2006	2005	2004
Operating Revenues	$ 99	$ 74	$ 71
Operation and Maintenance	37	30	27
Depreciation, Depletion and Amortization	27	20	18
Taxes Other Than Income	11	11	7
Asset (Gains) and Losses, Net	(3)	-	-
Operating Income	27	13	19
Other (Income) and Deductions	13	8	10
Income Tax Provision	5	1	3
Net Income	$ 9	$ 4	$ 6

Operating revenues increased $25 million in 2006 due to increased Barnett shale production and increased $3 million in 2005 due primarily to higher gas prices.

Operations and maintenance expense increased $7 million in 2006 and $3 million in 2005. Increases are associated with the addition of approximately 285 net producing wells during the three-year period.

Depreciation, depletion and amortization increased $7 million in 2006 and $2 million in 2005. The year-to-year increases were associated with higher gas production and higher finding costs associated with Barnett shale wells.

Taxes other than income were the same in 2006 due to severance taxes that were impacted by lower gas prices, which was offset by higher gas production, and increased $4 million in 2005 due to higher severance taxes associated with gas price increases on relatively flat Antrim gas volumes.

Assets (gains) and losses, net increased $3 million in 2006 primarily due to the sale of a working interest in unproved property.

Other income and deductions increased $5 million in 2006 and decreased $2 million in 2005. Interest expense was the primary contributor to the variances. The 2006 increase in interest expense was attributed to higher average affiliate notes payable balances.

Outlook – We expect to continue to develop our proved areas and test unproved areas in Michigan and Texas. Evaluation of Barnett shale test wells in up to three new areas is ongoing. During 2007, we expect Barnett Shale production of 8.7 Bcfe of natural gas compared with approximately 4.1 Bcfe in 2006 and Antrim Shale production roughly equivalent to the 21.5 Bcfe produced in 2006. We expect to invest a combined amount of approximately $150 million to $170 million in our Unconventional Gas Production business in 2007. We are exploring the sale of a portion of our Unconventional Gas Production assets which will allow us to monetize value from our more mature holdings, while retaining the ability to benefit from the upside of our earlier stage holdings.

Power and Industrial Projects

Power and Industrial Projects is comprised primarily of projects that deliver utility-type services to industrial, commercial and institutional customers, and biomass energy projects. We provide utility-type services using project assets usually located on 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. We own and operate three gas-fired peaking electric generating plants and a biomass-fired electric generating plant and operate one additional gas-fired power plant under contract. Additionally, we own a gas-fired peaking electric generating plant that was taken out of service in September 2006. We develop, own and operate landfill gas recovery systems throughout the United States. We produce metallurgical coke from two coke batteries. The production of coke from our coke batteries generates production tax credits.

Factors impacting income: Power and Industrial Projects' reported a net loss of $80 million in 2006 and net income of $4 million in 2005. The 2006 net loss is primarily due to impairments. The 2005 net income is attributed to the acquisitions of four on-site energy projects and coke operations in 2005.

(in Millions)	2006	2005	2004
Operating Revenues	$ 409	$ 428	$ 448
Operation and Maintenance	366	329	384
Depreciation and Amortization	48	48	53
Taxes other than Income	12	14	8
Asset (Gains) and Losses, Reserves and Impairments, Net	75	(1)	-
Operating Income (Loss)	(92)	38	3
Other (Income) and Deductions	43	4	28
Minority Interest	1	37	11
Income Taxes			
Provision (Benefit)	(44)	5	(10)
Production Tax Credits	(12)	(12)	(9)
	(56)	(7)	(19)
Net Income (Loss)	$ (80)	$ 4	$ (17)

Operating revenues decreased $19 million in 2006 and $20 million in 2005. The 2006 decrease is primarily due to lower coke prices and lower pulverized coal sales. The 2005 decrease reflects the impact from the sale of our interest in a coke battery in 2005 offset by increases at another owned coke battery due to increased output and increased prices. The 2006 and 2005 decreases were 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 $37 million in 2006 and decreased $55 million in 2005, reflecting the 2005 acquisitions of three on-site energy projects and coke operations. The 2005 decrease reflects the impact from the sale of an interest in a coke battery in 2005 resulting in a decrease in expense offset by increases in costs at another owned coke battery reflecting increased output.

Asset (gains) and losses, reserves and impairments, net 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 increased $39 million in 2006 primarily due to a $32 million impairment of a 50% equity interest in a natural gas-fired generating plant.

Income taxes declined $49 million in 2006 and increased $12 million in 2005, reflecting changes in pre-tax income.

Outlook - 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. The coke battery and landfill gas recovery businesses generate production tax credits that are subject to an oil price-related phase-out. Due to the relatively low level of production tax credits generated by our coke battery and landfill gas recovery business, a partial or full phase-out of production tax credits in these two businesses is not expected to have a material adverse impact on our Consolidated Statements of Operations, Cash Flow and Financial Position. We are exploring the combination of a sale of an equity interest in, and recapitalization of, some of the assets of the Power and Industrial Projects business, including the sale or restructuring of the power generation assets. In February 2007, we entered into an agreement to sell our Georgetown peaking electric generating facility. The sale is subject to receipt of regulatory approval and is expected to close in the second half of 2007.

Energy Trading

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

Factors impacting income: Net income increased $139 million in 2006 and decreased $128 million in 2005. 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. The 2005 decrease is attributed to decreased mark-to-market and realized power and gas positions.

(in Millions)	2006	2005	2004
Operating Revenues	$ 830	$ 977	$ 665
Fuel, Purchased Power and Gas	616	984	486
Gross Margin	214	(7)	179
Operation and Maintenance	65	43	41
Depreciation and Amortization	6	4	3
Taxes Other Than Income	1	(1)	-
Operating Income (Loss)	142	(53)	135
Other (Income) and Deductions	(3)	13	5
Income Tax Provision (Benefit)	49	(23)	45
Net Income (Loss)	$ 96	$ (43)	$ 85

Gross margin increased $221 million in 2006 and decreased $186 million in 2005. 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. The 2005 decrease is due to a $121 million mark-to-market decrease on power and gas positions and a $66 million decrease in realized power and gas positions. The 2005 results reflect the economically favorable decision in early 2005 to delay previously planned withdrawals from gas storage due to a decrease in the current price for natural gas and an increase in the forward price for natural gas.

Operation and maintenance expense increased $22 million in 2006 and $2 million in 2005. The 2006 increases were 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 decreased $16 million in 2006 and increased $8 million in 2005. The 2006 decrease is attributed to $6 million of lower intercompany interest expense and $8 million of higher intercompany interest income resulting from favorable operating cash flows to fund intercompany loans.

Income tax provision increased $72 million in 2006 and decreased $68 million in 2005 primarily due to variations in pre-tax earnings.

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 and pipelines and power transmission contracts. The financial instruments are deemed derivatives, whereas the owned gas inventory, pipelines and storage assets are not derivatives. As a result, we will experience earnings volatility as derivatives are marked to market without revaluing the underlying non-derivative assets. The majority of such earnings volatility is associated with the natural gas storage cycle, which does not coincide with the calendar and fiscal year, but runs annually from April of one year to March of the next year. Our strategy is to economically manage the price risk of storage with over-the-counter forwards and futures. This results in gains and losses that are recognized in different interim and annual accounting periods. We are exploring strategic options for the energy trading business.

See "Fair Value of Contracts" section that follows.

Synthetic Fuel

Synthetic Fuel is comprised of the nine synfuel plants that we operate and that produce synthetic fuel. The production of synthetic fuel from the synfuel plants generates production tax credits.

Factors impacting income: Synthetic Fuel net income decreased $257 million in 2006 and increased $106 million in 2005. The decline in 2006 was 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. The increase in 2005 reflects higher gains recognized from selling interests in our synfuel plants, gains on synfuel hedges, and increased levels of production tax credits.

(in Millions)	2006	2005	2004
Operating Revenues	$ 863	$ 927	$ 650
Operation and Maintenance	1,019	1,167	832
Depreciation and Amortization	24	58	33
Taxes other than Income	12	20	8
Asset (Gains) and Losses, Reserves and Impairments, Net	40	(367)	(219)
Operating Income (Loss)	(232)	49	(4)
Other (Income) and Deductions	(20)	(34)	(43)
Minority Interest	(251)	(318)	(223)
Income Taxes			
Provision (Benefit)	14	139	92
Production Tax Credits	(23)	(43)	(29)
	(9)	96	63
Net Income	$ 48	$ 305	$ 199

Operating revenues decreased $64 million in 2006 and increased $277 million in 2005. Revenues were lower in 2006 due to our decision to temporarily idle production at all nine of the synfuel facilities. Revenues increased in 2005 primarily reflecting higher synfuel sales due to increased production.

Operation and maintenance expense decreased $148 million in 2006 and increased $335 million in 2005. Operation and maintenance expense declined in 2006 due to our decision to temporarily idle production at all nine of the synfuel facilities for a portion of the year. Operating and maintenance expense in 2005 increased reflecting costs associated with increased synthetic fuel production.

Asset (gains) and losses, reserves and impairments, net decreased $407 million in 2006 and increased $148 million in 2005. In 2006 and 2005, we deferred gains from the sale of the synfuel facilities, including in 2006, a portion of gains related to fixed payments. Due to the increase in oil prices and the resulting decrease in production and sales volumes, we recorded an accrual for contractual partners' obligations of $79 million pre-tax in 2006 reflecting the possible refund of amounts equal to our partners' capital contributions or for operating losses that would normally be paid by our partners. We recorded other synfuel-related reserves and impairments in 2006 of $78 million. 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 2006 synfuel hedge mark-to-market gains of $60 million compared with net 2005 synfuel hedge mark-to-market gains of $48 million. In 2004, we recorded mark-to-market losses of $12 million. See Note 14 of the Notes to Consolidated Financial Statements.

(in Millions)	2006	2005	2004
Components of Synfuel (Gains) Losses, Reserves and Impairments, Net			
Gains recognized associated with fixed payments	$ (43)	$ (132)	$ (95)
Gains recognized associated with variable payments	(14)	(187)	(136)
Reserves recorded for contractual partners' obligations	79	-	-
Other reserves and impairments, including partners' share (1)	78	-	-
Hedge (gains) losses (mark-to-market)			
Hedges for 2005 exposure	-	(2)	12
Hedges for 2006 exposure	(66)	(40)	-
Hedges for 2007 exposure	6	(6)	-
	$ 40	$ (367)	$ (219)

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

Minority interest decreased $67 million in 2006 and increased $95 million in 2005, reflecting our partners' share of operating losses associated with synfuel operations, as well as our partners' $70 million share of the asset impairment in 2006. 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 declined $105 million in 2006 and increased $33 million in 2005, reflecting changes in pre-tax income due to synfuel related loss reserves and the impairment of fixed assets, compared to pre-tax income in 2005.

Outlook - Due to the implementation of our hedging strategy, we expect to continue to operate the synfuel plants through December 31, 2007, when synfuel-related production tax credits expire.

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, assets held for sale, and energy-related investments.

Factors impacting income: Corporate & Other results declined by $9 million in 2006 and declined $40 million in 2005. The 2006 decline was primarily due to higher Michigan Single Business Taxes. The 2005 decline was primarily a result of the parent company not allocating merger interest to Detroit Edison and MichCon. Partially offsetting 2005 increased expenses were reduced Michigan Single Business Taxes and gains on the sale of non-strategic assets.

DISCONTINUED OPERATIONS

DTE Georgetown (Georgetown) - We own Georgetown, an 80 MW natural gas-fired peaking electric generating plant. In the fourth quarter of 2006, management approved the marketing of Georgetown 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. We did not recognize an impairment loss since the carrying value of Georgetown's assets, less costs to sell approximated its fair value. In February 2007, we entered into an agreement to sell our Georgetown peaking electric generating facility. The sale is subject to receipt of regulatory approval and is expected to close in the second half of 2007.

DTE Energy Technologies (Dtech) - We own Dtech, which 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. We recognized a net of tax restructuring loss of $23 million during the third quarter of 2005 primarily representing the write down to fair value of the assets of Dtech, less costs to sell, and the write-off of goodwill. As we execute the restructuring plan, there may be adjustments to amounts recorded related to the impairment and exit costs.

Southern Missouri Gas Company (SMGC) - We owned SMGC, a public utility engaged in the distribution, transmission and sale of natural gas in southern Missouri. In the first quarter of 2004, management approved the marketing of SMGC for sale. As of March 31, 2004, SMGC met the criteria of an asset "held for sale" and we have reported its operating results as a discontinued operation. We recognized a net of tax impairment loss of approximately

$7 million, representing the write-down to fair value of the assets of SMGC, less costs to sell, and the write-off of allocated goodwill. In November 2004, we entered into a definitive agreement providing for the sale of SMGC. Regulatory approval was received in April 2005 and the sale closed in May 2005. During the second quarter of 2005, we recognized a net of tax gain of $2 million.

International Transmission Company (ITC) - In February 2003, we sold ITC, our electric transmission business, to affiliates of Kohlberg Kravis Roberts & Co. and Trimaran Capital Partners, LLC. Through December 31, 2004, we recorded a gain of $58 million (net of tax). During the second quarter of 2005, the gain was adjusted to $56 million (net of tax).

See Note 4 of the Notes to Consolidated Financial Statements.

CUMULATIVE EFFECT OF ACCOUNTING CHANGES

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 *FASB Interpretation FIN No. 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. Our strategic direction anticipates base level capital investments and expenditures for existing businesses in 2007 of up to $1.4 billion. The capital needs of our utilities will increase due primarily to environmental related expenditures. We may spend an additional $125 million on growth-related projects within our non-utility businesses in 2007.

Capital spending for general corporate purposes will increase in 2007, primarily as a result of environmental spending. We anticipate environmental expenditures of approximately $253 million in 2007 and up to approximately $2.3 billion of future capital expenditures to satisfy both existing and proposed new requirements.

We expect non-utility capital spending will approximate $300 million to $400 million annually for the next several years. Capital spending for growth of existing or new businesses will depend on the existence of opportunities that meet our strict risk-return and value creation criteria.

Debt maturing in 2007 totals approximately $346 million.

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

(in Millions)	2006	2005	2004
Cash and Cash Equivalents			
Cash Flow From (Used For)			
Operating activities:			
Net income	$ 433	$ 537	$ 431
Depreciation, depletion and amortization	1,014	872	744
Deferred income taxes	28	147	129
Gain on sale of synfuel and other assets, net and synfuel impairment	28	(405)	(236)
Working capital and other	(47)	(150)	(73)
	1,456	1,001	995
Investing activities:			
Plant and equipment expenditures - utility	(1,126)	(850)	(815)
Plant and equipment expenditures - non-utility	(277)	(215)	(89)
Acquisitions, net of cash acquired	(42)	(50)	-
Proceeds from sale of synfuels and other assets	313	409	325
Restricted cash and other investments	(62)	(96)	(102)
	(1,194)	(802)	(681)
Financing activities:			
Issuance of long-term debt and common stock	629	1,041	777
Redemption of long-term debt	(687)	(1,266)	(759)
Short-term borrowings, net	291	437	33
Repurchase of common stock	(61)	(13)	-
Dividends on common stock and other	(375)	(366)	(363)
	(203)	(167)	(312)
Net Increase in Cash and Cash Equivalents	$ 59	$ 32	$ 2

Cash from Operating Activities

A majority of the Company's 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 $900 million of cash during 2007-2009.

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 which was the result of improved revenues and gross margin stemming from a full year of higher rates granted in the 2004 rate orders and lower customer choice penetration. The working capital improvement was driven by MichCon which 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 which resulted from pension and Voluntary Employees Beneficiary Association (VEBA) contributions totaling $271 million in 2006.

Cash from operations totaling $1.0 billion in 2005 was up $6 million from the comparable 2004 period. The operating cash flow comparison reflects an increase of over $83 million in net income, after adjusting for non-cash items (depreciation, depletion, amortization, deferred taxes and gains), substantially offset by a $77 million increase in working capital and other requirements. Most of the improvement was driven by higher net income at Detroit Edison which was the result of improved revenues and gross margin stemming from higher rates granted in the 2004 rate orders, warmer weather, and lower customer choice penetration. The offsetting increase in working capital requirements was driven by a $127 million PSCR under-recovery in 2005 as compared to a $112 million over-recovery in 2004. Working capital requirements also reflect the higher cost of gas at MichCon and our Energy Trading segment. MichCon's working capital and other requirements were $136 million higher in 2005 compared to 2004 primarily due to the impact of higher gas costs. This impact was reflected by accounts receivable balances that were $198 million higher at December 31, 2005 than the previous year at MichCon. The increase in working capital requirements was mitigated by lower income tax payments in 2005 and company initiatives to improve cash flow, including better inventory management, cash sales transactions and the utilization of letters of credit.

Outlook - We expect cash flow from operations to increase over the long-term primarily due to improvements from higher earnings at our utilities. We are incurring costs associated with implementation of our Performance Excellence Process, but we expect to realize sustained net cost savings beginning 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 $900 million of synfuel-related cash impacts from 2007 through 2009, which consists of cash from operations and proceeds from option hedges, and approximately $500 million of tax credit carryforward utilization and other tax benefits that are expected to reduce future tax payments. The redeployment of this cash represents a unique opportunity to increase shareholder value and strengthen our balance sheet. We expect to use any such cash and the potential cash from monetization of certain of our non-utility assets and operations to reduce debt and repurchase common stock, and to continue to pursue growth investments that meet our strict risk-return and value creation criteria. We repurchased one million shares of common stock in December 2006. Our objectives for cash redeployment are to strengthen the balance sheet and coverage ratios to improve our current credit rating and outlook, and to have any monetization be accretive to earnings per share.

Cash from Investing Activities

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

Net cash outflows relating to investing activities increased $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, Enterprise Business Systems development and distribution projects at Detroit Edison, pipeline reliability and inventory management projects at MichCon, and growth-oriented projects across our non-utility segments.

Net cash outflows relating to investing activities increased $121 million in 2005. The increase was primarily due to increased capital expenditures, partially offset by higher synfuel proceeds. Spending on growth project investments increased $123 million in 2005 while spending on environmental projects was $44 million higher than the 2004 period.

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

Cash from Financing Activities

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

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

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

Net cash used for financing activities improved $145 million in 2005 due primarily to the issuance of common stock which resulted from the conversion of our equity security units.

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

In August 2006, DTE Energy and Detroit Edison filed a combined shelf registration statement for the issuance of securities in an unlimited amount for three years from its effective date. MichCon has a separate effective registration statement providing for the issuance of $200 million of securities.

Common stock issuances or repurchases can also be a source or use of cash. In January 2005, we announced that the DTE Energy Board of Directors has authorized the repurchase of up to $700 million in common stock through 2008. The authorization provides Company management with flexibility to pursue share repurchases from time to time, and will depend on future cash flows and investment opportunities. We repurchased one million shares of our common stock in December 2006. We also contributed $170 million of DTE Energy common stock to our pension plan in the first quarter of 2004. In August 2005, we issued 3.7 million shares of common stock in conjunction with the settlement of the stock purchase component of our equity security units.

Contractual Obligations

The following table details our contractual obligations for debt redemptions, leases, purchase obligations and other long-term obligations as of December 31, 2006:

(in Millions)	Total	Less Than 1 Year	1-3 Years	4-5 Years	After 5 Years
Contractual Obligations					
Long-term debt:					
Mortgage bonds, notes and other	$ 6,163	$ 236	$ 1,124	$ 1,061	$ 3,742
Securitization bonds	1,295	111	391	314	479
Trust preferred-linked securities	289	-	-	-	289
Capital lease obligations	120	14	44	21	41
Interest	6,433	471	1,298	659	4,005
Operating leases	333	53	102	51	127
Electric, gas, fuel, transportation and storage purchase obligations (1)	6,249	3,007	2,437	135	670
Other long-term obligations	291	157	75	25	34
Total obligations	$ 21,173	$ 4,049	$ 5,471	$ 2,266	$ 9,387

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

Credit Ratings

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

We have issued guarantees for the benefit of various non-utility subsidiaries. In the event that our credit rating is downgraded to below investment grade, certain of these guarantees would require us to post cash or letters of credit valued at approximately $383 million at December 31, 2006. 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.

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

CRITICAL ACCOUNTING ESTIMATES

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

Regulation

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

If we were to discontinue the application of SFAS No. 71 on all our operations, we estimate that the extraordinary loss would be as follows:

(in Millions)	
Utility	
Detroit Edison (1)	$ (161)
MichCon	(46)
Total	$ (207)

(1) Excludes securitized regulatory assets

Management believes that currently available facts support the continued application of SFAS No. 71 and that all regulatory assets and liabilities are recoverable or refundable in the current rate environment. See Note 6 of the Notes to Consolidated Financial Statements.

Risk Management and Trading Activities

All derivatives are recorded at fair value and shown as "Assets or liabilities from risk management and trading activities" in the Consolidated Statement of Financial Position. Risk management activities are accounted for in accordance with SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended.

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

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

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

Production Tax Credits

We generate production tax credits from our synfuel, coke battery and landfill gas recovery operations. We recognize earnings as tax credits are generated at our facilities in one of two ways. First, to the extent we have sold an interest in our synfuel facilities to third parties, we recognize gains as synfuel is produced and sold, and when there is persuasive evidence that the sales proceeds have become fixed or determinable, 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 $295 million in 2006 as compared to $617 million in 2005, and $449 million in 2004. The portion of tax credits generated for our own account was $35 million in 2006, as compared to $55 million in 2005, and $38 million in 2004, with the remaining credits generated allocated to third party partners.

Goodwill

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

As of December 31, 2006, our goodwill totaled $2.1 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.

We also have $4 million of goodwill allocated to the Synthetic Fuel reporting unit. The value of the Synthetic Fuel reporting unit has been impacted by the anticipated phase-out of tax credits. As of December 31, 2006, we have evaluated the impact of a phase-out of synfuel tax credits on our valuation assumptions. We have determined that the fair value of the Synthetic Fuel reporting unit exceeds the carrying value and no impairment of goodwill exists. These assumptions may change as the value of the synfuel tax credits change.

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

Based on our 2006 goodwill impairment test, we determined that the fair value of our remaining operating reporting units exceed their carrying value and no impairment existed. We will continue to monitor our estimates and assumptions regarding future cash flows. While we believe our assumptions are reasonable, actual results may differ from our projections.

Pension and Postretirement Costs

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

We had pension costs for qualified pension plans of $125 million in 2006 (including Special Termination Benefits of $49 million), $90 million in 2005, and $81 million in 2004. Postretirement benefits costs for all plans were $197 million in 2006 (including Special Termination Benefits of $8 million), $155 million in 2005, and $125 million in 2004. Pension and postretirement benefits costs for 2006 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 input from our consultants, including their review of asset class risk and return expectations as well as inflation assumptions. Projected returns are based on broad equity and bond markets. Our 2007 expected long-term rate of return on plan assets is based on an asset allocation assumption utilizing active investment management of 65% in equity markets, 20% in fixed income markets, and 15% 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 2007. 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, 2006, we had $39 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 decreased from 5.9% at December 31, 2005 to 5.7% at December 31, 2006. Due to recent company contributions, financial market performance and lower discount rates, we estimate that our 2007 pension costs will approximate $66 million (excluding Special Termination Benefits) compared to $85 million (excluding Special Termination Benefits) in 2006 and our 2007 postretirement benefit costs will approximate $184 million compared to $189 million (excluding Special Termination Benefits of $8 million) in 2006. In the last several years, we have made modifications to the pension and postretirement benefit plans to mitigate the earnings impact of higher costs. Future actual pension and postretirement benefit costs will depend on future investment performance, changes in future discount rates and various other factors related to plan design. Additionally, future pension costs for Detroit Edison will be affected by a pension tracking mechanism, which was authorized by the MPSC in its November 2004 rate order. The tracking mechanism provides for the recovery or refunding of pension costs above or below the amount reflected in Detroit Edison's base rates. In April 2005, the MPSC approved the deferral of the non-capitalized portion of MichCon's negative pension expense. MichCon will record a regulatory liability for any negative pension costs, as determined under generally accepted accounting principles.

Lowering the expected long-term rate of return on our plan assets by one-percentage-point would have increased our 2006 qualified pension costs by approximately $22 million. Lowering the discount rate and the salary increase assumptions by one-percentage-point would have increased our 2006 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 2006 by approximately $25 million.

The market value of our pension and postretirement benefit plan assets has been affected by the financial markets. The value of our plan assets was $3.3 billion at December 31, 2004 and November 30, 2005. The value at November 30, 2006 was $3.5 billion. The investment performance returns and declining discount rates required us to recognize an additional minimum pension liability, an intangible asset and an entry to other comprehensive loss (shareholders' equity) in 2004 and 2005. 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 158 was an increase in pension and postretirement benefit liabilities of approximately $1.3 billion. We requested and received agreement from the MPSC to record the additional liability amounts for the Detroit Edison and MichCon benefit plans on the Statement 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.

Pension and postretirement costs and pension cash funding requirements may increase in future years without substantial returns in the financial markets. We made a $170 million contribution to our pension plan in the form of DTE Energy common stock in 2004. We did not make pension contributions in 2005 and made a $180 million cash contribution in 2006. At the discretion of management, we anticipate making up to a $180 million contribution to our qualified pension plans in 2007 and up to $600 million over the next five years. Also, we anticipate making up to a $15 million contribution to our nonqualified benefit plans in 2007 and up to $35 million over the next five years. We contributed $80 million to our postretirement plans in 2004. We did not contribute to our postretirement plans in 2005 and made a $116 million contribution to our postretirement benefit plans in 2006. At the discretion of management, we anticipate making up to a $116 million contribution to our postretirement plans in 2007 and up to $580 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 $17 million in 2006, $20 million in 2005 and $16 million in 2004.

See Note 16 of the Notes to Consolidated Financial Statements.

Allowance for Doubtful Accounts

We establish an allowance for doubtful accounts based upon factors surrounding the credit risk of specific customers, historical trends, economic conditions, age of receivables and other information. Higher customer bills due to increased gas prices, the lack of adequate levels of assistance for low-income customers and economic conditions have also contributed to the increase in past due receivables. As a result of these factors, our allowance for doubtful accounts increased in 2005 and 2006. We believe the allowance for doubtful accounts is based on reasonable estimates. As part of the 2005 rate order for MichCon, the MPSC provided for the establishment of an uncollectible accounts tracking mechanism that partially mitigates the impact associated with MichCon uncollectible expenses. However, failure to make continued progress in collecting our past due receivables in light of rising energy prices would unfavorably affect operating results and cash flow.

Legal and Tax Reserves

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

ENVIRONMENTAL MATTERS

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

Electric Utility

Air - Detroit Edison is subject to EPA ozone transport and acid rain regulations that limit power plant emissions of sulfur dioxide and nitrogen oxides. In March 2005, EPA issued additional emission reduction regulations relating to ozone, fine particulate, regional haze and mercury air pollution. The new rules will lead to additional controls on fossil-fueled power plants to reduce nitrogen oxide, sulfur dioxide and mercury emissions. To comply with these requirements, Detroit Edison has spent approximately $875 million through 2006. We estimate Detroit Edison will incur future capital expenditures of up to $222 million in 2007 and up to $2 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.

We may also incur liabilities as a result of potential future requirements to address the climate change issue. 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 and methane, in the atmosphere. We cannot predict the impact any legislative action may have on the Company.

Water - In response to an EPA regulation, currently under judicial review, Detroit Edison may be 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 $53 million over the next three to five 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 which may result in a delay in compliance requirements. The court decision also raised the possibility that the Company may have to install cooling towers at some facilities. 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 two 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 $11 million as of December 31, 2006 for the remediation of these sites over the next several years. In addition, Detroit Edison expects to make approximately $5 million of capital improvements to the ash landfill in 2007.

Gas Utility

Contaminated Sites - Prior to the construction of major interstate natural gas pipelines, gas for heating and other uses was manufactured locally from processes involving coal, coke or oil. Gas Utility owns, or previously owned, 15 former MGP sites. Investigations have revealed contamination related to the by-products of gas manufacturing at each site. In addition to the MPG sites, Gas Utility is also in the process of cleaning up other contaminated sites. Cleanup activities associated with these sites will be conducted over the next several years. As a result of these determinations, we have recorded liabilities of $41 million and $1 million for the MGPs and other contaminated sites, respectively. It is estimated that Gas Utility may incur $5 million in expenses related to cleanup costs in 2007.

In 1993, a cost deferral and rate recovery mechanism was approved by the MPSC for investigation and remediation costs incurred at former MGP sites in excess of this reserve. After a study was completed in 1995, Gas Utility accrued an additional liability and a corresponding regulatory asset of $35 million. During 2006, we spent approximately $2 million investigating and remediating these former MGP sites. In December 2006, we retained multiple environmental consultants to estimate the project cost to remediate each MGP site. We accrued an additional $7 million in remediation liabilities associated with former MGP holders and additional cleanup cost, to increase the reserve balance to $41 million as of December 31, 2006.

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

Other

Our non-utility affiliates are subject to a number of environmental laws and regulations dealing with the protection of the environment from various pollutants. We are in the process of installing new environmental equipment at our coke battery facility in Michigan. We expect the project to be completed within one year. 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.

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 are implementing EBS software including, among others, products developed by SAP AG and MRO Software, Inc. The first phase of implementation occurred in 2005 in the regulated electric fossil generation unit. Additional phases of implementation are planned for 2007. The conversion of data and the implementation and operation of EBS will be continuously monitored and reviewed and should ultimately strengthen our internal control structure and lead to increased cost efficiencies. Although our implementation plan includes detailed testing and contingency arrangements to ensure a smooth and successful transition, we can provide no assurance that complications will not arise that could interrupt our operations.

We have spent approximately $330 million through the end of 2006 and expect total spending over the life of the project to be between $375 million and $400 million. We expect the benefits of lower costs, faster business cycles, repeatable and optimized processes, enhanced internal controls, improvements in inventory management and reductions in system support costs to outweigh the expense of our investment in this initiative.

MISO

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

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

MISO is compensated for assuring grid reliability and for supporting the energy market through FERC-approved rates charged to load. Detroit Edison became a non-transmission owning member of MISO in compliance with section 10w (1) of PA 141. The MPSC has ordered that MISO costs charged to Detroit Edison should be recovered through the PSCR mechanism.

FEDERAL ENERGY POLICY ACT OF 2005

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

- establishes mandatory electric reliability standards;
- repeals the Public Utility Holding Company Act of 1935;
- renews the Price Anderson Act for twenty years which provides liability protection for nuclear power plants;
- provides financial incentives for nuclear license applications completed by 2008;
- increases funding levels for the Low-Income Home Energy Assistance Program; and
- increases FERC oversight responsibilities for the electric utility industry.

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

NEW ACCOUNTING PRONOUNCEMENTS

See Note 3 of the Notes to Consolidated Financial Statements.

FAIR VALUE OF CONTRACTS

The following disclosures provide enhanced transparency of the derivative activities and position of our trading businesses and our other businesses.

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

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

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

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

- "Proprietary Trading" represents derivative activity transacted with the intent of taking a view, capturing market price changes, or putting capital at risk. This activity is speculative in nature as opposed to hedging an existing exposure.
- "Structured Contracts" represents derivative activity transacted with the intent to capture profits by originating substantially hedged positions with wholesale energy marketers, utilities, retail aggregators and alternative energy suppliers. Although transactions are generally executed with a buyer and seller simultaneously, some positions remain open until a suitable offsetting transaction can be executed.
- "Economic Hedges" represents derivative activity associated with assets owned and contracted by DTE Energy, including forward sales of gas production and trades associated with owned transportation and storage capacity. Changes in the value of derivatives in this category economically offset changes in the value of underlying non-derivative positions, which do not qualify for fair value accounting. The difference in accounting treatment of derivatives in this category and the underlying non-derivative positions can result in significant earnings volatility as discussed in more detail in the preceding Results of Operations section.
- "Other Non-Trading Activities" primarily represent derivative activity associated with our gas reserves and synfuel operations. A substantial portion of the price risk associated with the gas reserves has been mitigated through 2013. Changes in the value of the hedges are recorded as "Assets or Liabilities from risk management and trading activities, " with an offset in other comprehensive income to the extent that the hedges are deemed effective. Oil-related derivative contracts have been executed to economically hedge cash flow risks related to underlying, non-derivative synfuel related positions through 2007. The amounts shown in the following tables exclude the value of the underlying gas reserves and synfuel proceeds including changes therein.

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

The following tables provide details on changes in our mark-to-market net asset or (liability) position during 2006:

	Trading Activities				Other	
(in Millions)	Proprietary Trading	Structured Contracts	Economic Hedges	Total	Non-Trading Activities	Total
MTM at December 31, 2005	$ (108)	$ (136)	$ (110)	$ (354)	$ (140)	$ (494)
Reclassed to realized upon settlement	(21)	83	57	119	92	211
Liquidation of in-the-money positions (1)	-	-	(123)	(123)	-	(123)
Changes in fair value recorded to income	(5)	35	140	170	(6)	164
Amortization of option premiums	114	(2)	-	112	(40)	72
Amounts recorded to unrealized income	88	116	74	278	46	324
Amounts recorded in OCI	-	14	-	14	(3)	11
Option premiums paid and other	11	4	-	15	73	88
MTM at December 31, 2006	$ (9)	$ (2)	$ (36)	$ (47)	$ (24)	$ (71)

(1) In conjunction with our overall tax planning and cash initiatives, we monetized certain in-the-money contracts while simultaneously entering into at-the-market contracts with various counterparties. This had the impact of optimizing taxable income and cash flow while having minimal impact on earnings.

The following table provides a current and noncurrent analysis of "Assets and Liabilities from risk management and trading activities", as reflected on the Consolidated Statement of Financial Position as of December 31, 2006. Amounts that relate to contracts that become due within twelve months are classified as current and all remaining amounts are classified as noncurrent.

(in Millions)	Trading Activities: Proprietary Trading	Trading Activities: Structured Contracts	Trading Activities: Economic Hedges	Trading Activities: Eliminations	Trading Activities: Totals	Other Non-Trading Activities	Total Assets (Liabilities)
Current assets	$ 62	$ 193	$ 108	$ (57)	$ 306	$ 155	$ 461
Noncurrent assets	7	55	108	(7)	163	1	164
Total MTM assets	69	248	216	(64)	469	156	625
Current liabilities	(71)	(189)	(132)	57	(335)	(102)	(437)
Noncurrent liabilities	(7)	(61)	(120)	7	(181)	(78)	(259)
Total MTM liabilities	(78)	(250)	(252)	64	(516)	(180)	(696)
Total MTM net assets (liabilities)	$ (9)	$ (2)	$ (36)	$ -	$ (47)	$ (24))	$ (71)

Maturity of Fair Value of MTM Energy Contract Net Assets

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

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

The table below shows the maturity of our MTM positions:

(in Millions) Source of Fair Value	2007	2008	2009	2010 and Beyond	Total Fair Value
Proprietary Trading	$ (9)	$ -	$ -	$ -	$ (9)
Structured Contracts	4	(6)	(4)	4	(2)
Economic Hedges	(24)	(8)	(4)	-	(36)
Total Energy Trading Activities	(29)	(14)	(8)	4	(47)
Other Non-Trading Activities	53	(61)	(16)	-	(24)
Total	$ 24	$ (75)	$ (24)	$ 4	$ (71)

Item 7A. Quantitative and Qualitative Disclosures About Market 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 to manage this risk. The approaches include 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.

The non-utility businesses have risk in conjunction with electricity, natural gas, crude oil and coal.

Our Power and Industrial Projects and Synthetic Fuel segments are subject to crude oil, electricity, natural gas and coal based product price risk. As previously discussed, production tax credits generated by DTE Energy's synfuel, coke battery and landfill gas recovery operations are subject to phase-out if domestic crude oil prices reach certain levels. The benefits associated with tax credits may be subject to changes in federal tax law. Also, we have entered into a series of derivative contracts for 2007 to economically hedge the impact of oil prices on a portion of our synfuel cash flow. See Note 14 of the Notes to Consolidated Financial Statements. To limit our exposure to the other commodities 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 and crude oil price fluctuations. These risks are managed through its energy marketing and trading operations through the use of forward energy, capacity, storage 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, 2006:

(in Millions)	Credit Exposure before Cash Collateral	Cash Collateral	Net Credit Exposure
Investment Grade (1)			
A- and Greater	$ 526	$ (126)	$ 400
BBB+ and BBB	111	-	111
BBB-	107	-	107
Total Investment Grade	744	(126)	618
Non-investment grade (2)	68	-	68
Internally Rated - investment grade (3)	104	-	104
Internally Rated - non-investment grade (4)	9	(4)	5
Total	$ 925	$ (130)	$ 795

(1) This category includes counterparties with minimum credit ratings of Baa3 assigned by Moody's Investors Service (Moody's) and BBB- assigned by Standard & Poor's Rating Group, a division of the McGraw-Hill Companies, Inc. (Standard & Poor's). The five largest counterparty exposures combined for this category represented 27% of the total gross credit exposure.

(2) This category includes counterparties with credit ratings that are below investment grade. The five largest counterparty exposures combined for this category represented less than 7% of the total gross credit exposure.

(3) This category includes counterparties that have not been rated by Moody's or Standard & Poor's, but are considered investment grade based on DTE Energy's evaluation of the counterparty's creditworthiness. The five largest counterparty exposures combined for this category represented 7% of the total gross credit exposure.

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

Interest Rate Risk

DTE Energy is subject to interest rate risk in connection with the issuance of debt and preferred securities. In order to manage interest costs, we 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, 2006, the Company has 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 2011. Additionally, we may enter into fair value currency hedges to mitigate changes in the value of contracts or loans.

Summary of Sensitivity Analysis

We performed a sensitivity analysis to calculate the fair values of our commodity contracts, long-term debt instruments and foreign currency forward contracts. The sensitivity analysis involved increasing and decreasing forward rates at December 31, 2006 by a hypothetical 10% and calculating the resulting change in the fair values.

The results of the sensitivity analysis calculations follow:

(in Millions) Activity	Assuming a 10% increase in rates	Assuming a 10% decrease in rates	Change in the fair value of
Gas Contracts	$ (10)	$ 11	Commodity contracts
Power Contracts	$ (17)	$ 17	Commodity contracts
Oil Contracts	$ 78	$ (62)	Commodity options
Interest Rate Risk	$ (314)	$ 339	Long-term debt
Foreign Currency Risk	$ 2	$ (2)	Forward contracts