DTE ENERGY CO
Form 10-K
March 01, 2007

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K
ANNUAL REPORT PURSUANT TO SECTIONS 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2006
Commission file number 1-11607
DTE ENERGY COMPANY
(Exact name of registrant as specified in its charter)

Michigan	**38-3217752**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
2000 2nd Avenue, Detroit, Michigan	**48226-1279**
(Address of principal executive offices)	(Zip Code)

313-235-4000
(Registrant s telephone number, including area code)
Securities registered pursuant to Section 12(b) of the Act:

Title of each class	**Name of each exchange on which registered**
Common Stock, without par value, with contingent preferred stock purchase rights	New York Stock Exchange
7.8% Trust Preferred Securities *	New York Stock Exchange
7.50% Trust Originated Preferred Securities**	New York Stock Exchange

* Issued by DTE Energy Trust I. DTE Energy fully and unconditionally guarantees the payments of all amounts due on these securities to the extent DTE Energy Trust I has funds available for payment of such

distributions.

** Issued by DTE Energy Trust II. DTE Energy fully and unconditionally guarantees the payments of all amounts due on these securities to the extent DTE Energy Trust II has funds available for payment of such distributions.

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes þ No o

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15 (d) of the Act. Yes o No þ

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15 (d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes þ No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer þ Accelerated filer o Non-accelerated filer o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No þ

On June 30, 2006, the aggregate market value of the Registrant s voting and non-voting common equity held by non-affiliates was approximately $7.2 billion (based on the New York Stock Exchange closing price on such date). There were 177,123,754 shares of common stock outstanding at January 31, 2007.

Certain information in DTE Energy Company s definitive Proxy Statement for its 2007 Annual Meeting of Common Shareholders to be held May 3, 2007, which will be filed with the Securities and Exchange Commission pursuant to Regulation 14A, not later than 120 days after the end of the Registrant s fiscal year covered by this report on Form 10-K, is incorporated herein by reference to Part III (Items 10, 11, 12, 13 and 14) of this Form 10-K.

DTE Energy Company
Annual Report on Form 10-K
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DEFINITIONS

Coke and Coke Battery	Raw coal is heated to high temperatures in ovens to separate impurities, leaving a carbon residue called coke. Coke is combined with iron ore to create a high metallic iron that is used to produce steel. A series of coke ovens configured in a module is referred to as a battery.
Company	DTE Energy Company and any subsidiary companies
CTA	Costs to achieve, consisting of project management, consultant support and employee severance, related to the Performance Excellence Process
Customer Choice	Statewide initiatives giving customers in Michigan the option to choose alternative suppliers for electricity and gas.
Detroit Edison	The Detroit Edison Company (a direct wholly owned subsidiary of DTE Energy Company) and subsidiary companies
DTE Energy	DTE Energy Company, directly or indirectly the parent of Detroit Edison, MichCon and numerous non-utility subsidiaries
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
GCR	A gas cost recovery mechanism authorized by the MPSC, permitting MichCon to pass the cost of natural gas to its customers.
ITC	International Transmission Company (until February 28, 2003, a wholly owned subsidiary of DTE Energy Company)
MDEQ	Michigan Department of Environmental Quality
MichCon	Michigan Consolidated Gas Company (an indirect wholly owned subsidiary of DTE Energy) and subsidiary companies
MISO	Midwest Independent System Operator, a Regional Transmission Organization
MPSC	Michigan Public Service Commission
Non-utility	An entity that is not a public utility. Its conditions of service, prices of goods and services and other operating related matters are not directly regulated by the MPSC or the FERC.
NRC	Nuclear Regulatory Commission
PSCR	A power supply cost recovery mechanism authorized by the MPSC that allows Detroit Edison to recover through rates its fuel, fuel-related and purchased power expenses. The power supply cost recovery mechanism was suspended under Michigan s

	restructuring legislation (signed into law June 5, 2000), which lowered and froze electric customer rates and was reinstated by the MPSC effective January 1, 2004.
Production tax credits	Tax credits as authorized under Sections 45K and 45 of the Internal Revenue Code that are designed to stimulate investment in and development of alternate fuel sources. The amount of a production tax credit can vary each year as determined by the Internal Revenue Service.
Proved Reserves	Estimated quantities of natural gas, natural gas liquids and crude oil which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reserves under existing economic and operating conditions.

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Securitization	Detroit Edison financed specific stranded costs at lower interest rates through the sale of rate reduction bonds by a wholly-owned special purpose entity, the Detroit Edison Securitization Funding LLC.
SFAS	Statement of Financial Accounting Standards
Stranded Costs	Costs incurred by utilities in order to serve customers in a regulated environment that absent special regulatory approval would not otherwise be recoverable if customers switch to alternative energy suppliers.
Subsidiaries	The direct and indirect subsidiaries of DTE Energy Company
Synfuels	The fuel produced through a process involving chemically modifying and binding particles of coal. Synfuels are used for power generation and coke production. Synfuel production generates production tax credits.
Unconventional Gas	Includes those oil and gas deposits that originated and are stored in coal bed, tight sandstone and shale formations.

Units of Measurement

Bcf	Billion cubic feet of gas
Bcfe	Conversion metric of natural gas, the ratio of 6 Mcf of gas to 1 barrel of oil.
kWh	Kilowatthour of electricity
Mcf	Thousand cubic feet of gas
MMcf	Million cubic feet of gas
MW	Megawatt of electricity
MWh	Megawatthour of electricity

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Forward-Looking Statements

Certain information presented herein includes forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. Forward-looking statements involve certain risks and uncertainties that may cause actual future results to differ materially from those presently contemplated, projected, estimated or budgeted. Many factors may impact forward-looking statements including, but not limited to, the following:

- the higher price of oil and its impact on the value of production tax credits or the potential requirement to refund proceeds received from synfuel partners;
- the uncertainties of successful exploration of gas shale resources and inability to estimate gas reserves with certainty;
- the effects of weather and other natural phenomena on operations and sales to customers, and purchases from suppliers;
- economic climate and population growth or decline in the geographic areas where we do business;
- environmental issues, laws, regulations, and the cost of remediation and compliance;
- nuclear regulations and operations associated with nuclear facilities;
- implementation of electric and gas Customer Choice programs;
- impact of electric and gas utility restructuring in Michigan, including legislative amendments;
- employee relations and the impact of collective bargaining agreements;
- unplanned outages;
- access to capital markets and capital market conditions and the results of other financing efforts which can be affected by credit agency ratings;
- the timing and extent of changes in interest rates;
- the level of borrowings;
- changes in the cost and availability of coal and other raw materials, purchased power and natural gas;
- effects of competition;
- impact of regulation by the FERC, MPSC, NRC and other applicable governmental proceedings and regulations, including any associated impact on rate structures;
- contributions to earnings by non-utility subsidiaries;
- changes in and application of federal, state and local tax laws and their interpretations, including the Internal Revenue Code, regulations, rulings, court proceedings and audits;
- the ability to recover costs through rate increases;

- the availability, cost, coverage and terms of insurance;
- the cost of protecting assets against, or damage due to, terrorism;
- changes in and application of accounting standards and financial reporting regulations;
- changes in federal or state laws and their interpretation with respect to regulation, energy policy and other business issues;
- uncollectible accounts receivable;
- binding arbitration, litigation and related appeals;
- changes in the economic and financial viability of our suppliers, customers and trading counterparties, and the continued ability of such parties to perform their obligations to the Company; and
- timing, terms and proceeds from any asset sale or monetization.

New factors emerge from time to time. We cannot predict what factors may arise or how such factors may cause our results to differ materially from those contained in any forward-looking statement. Any forward-looking statements speak only as of the date on which such statements are made. We undertake no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events.

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Part I

Items 1. and 2. Business and Properties

General

In 1995, DTE Energy incorporated in the State of Michigan. Our utility operations consist primarily of Detroit Edison and MichCon. We also have five non-utility segments that are engaged in a variety of energy related businesses. In August 2005, the Energy Policy Act of 2005 repealed the Public Utility Holding Company Act of 1935 (PUHCA), effective February 8, 2006. A discussion of the Energy Policy Act of 2005 is in the Management s Discussion and Analysis section of this Form 10-K.

Detroit Edison is a Michigan corporation organized in 1903 and is a public utility subject to regulation by the MPSC and the FERC. Detroit Edison is engaged in the generation, purchase, distribution and sale of electricity to approximately 2.2 million customers in southeastern Michigan.

MichCon is a Michigan corporation organized in 1898 and is a public utility 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 customers throughout Michigan.

Our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and all amendments to such reports are available free of charge through the Investor Relations page of our website: *www.dteenergy.com*, as soon as reasonably practicable after they are filed with or furnished to the Securities and Exchange Commission (SEC). The information on our website is not, and shall not be deemed to be, a part of this Form 10-K or any other filing we make with the SEC. Our previously filed reports and statements are also available at the SEC s website: *www.sec.gov*.

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

Corporate Structure

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. See Note 18 of the Notes to Consolidated Financial Statements for financial information by segment for the last three years.

Electric Utility

Consists of Detroit Edison, the company s electric utility whose operations include the power generation and electric distribution facilities that service approximately 2.2 million residential, commercial, industrial and wholesale customers throughout southeastern Michigan.

Gas Utility

Consists of the gas distribution services provided by MichCon, a gas utility that purchases, stores and distributes natural gas throughout Michigan to approximately 1.3 million residential, commercial and industrial customers and Citizens Gas Fuel Company (Citizens), a gas utility that distributes natural gas in Adrian, Michigan.

Non-Utility Operations

Coal and Gas Midstream, primarily consisting of coal transportation and marketing, and gas pipelines, processing and storage;

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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, primarily 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 related investments.

Refer to our Management s Discussion and Analysis for an in-depth analysis of each segment s financial results. A description of each business unit follows.

ELECTRIC UTILITY

Description

Our Electric Utility segment consists of Detroit Edison, an electric utility subject to regulation by the MPSC and FERC. Detroit Edison is engaged in the generation, purchase, distribution and sale of electric energy to approximately 2.2 million customers in a 7,600 square mile area in southeastern Michigan.

Our plants are regulated by numerous federal and state governmental agencies, including, but not limited to, the MPSC, the FERC, the NRC, the EPA and the MDEQ. Electricity is generated from our numerous fossil plants, a hydroelectric pumped storage plant and a nuclear plant, and is purchased from electricity generators, suppliers and wholesalers.

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The electricity we produce and purchase is sold to four major classes of customers: residential, commercial, industrial and wholesale, principally throughout Michigan.

Revenue by Service

(in Millions)	**2006**	2005	2004
Residential	**$ 1,671**	$ 1,517	$ 1,345
Commercial	**1,603**	1,331	1,123
Industrial	**835**	697	557
Wholesale	**109**	73	65
Other	**350**	464	234
Subtotal	**4,568**	4,082	3,324
Interconnection sales (1)	**169**	380	244
Total Revenue	**$ 4,737**	$ 4,462	$ 3,568

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

Weather, economic factors, competition and electricity prices affect sales levels to customers. Our peak load and highest total system sales generally occur during the third quarter of the year, driven by air conditioning and other cooling-related demands.

Our operations are not dependent upon a limited number of customers, and the loss of any one or a few customers would not have a material adverse effect on Detroit Edison.

Fuel Supply and Purchased Power

Our power is generated from a variety of fuels and is supplemented with purchased power. We expect to have an adequate supply of fuel and purchased power to meet our obligation to serve customers. Our generating capability is heavily dependent upon the availability of coal. Coal is purchased from various sources in different geographic areas under agreements that vary in both pricing and terms. We expect to obtain the majority of our coal requirements through long-term contracts with the balance to be obtained through short-term agreements and spot purchases. We have six long-term and two short-term contracts for a total purchase of approximately 35 million tons of low-sulfur western coal to be delivered from 2007 to 2010. We also have ten contracts for the purchase of approximately 8 million tons of Appalachian coal to be delivered from 2007 through 2009. All of these contracts have fixed prices. We have approximately 90% of our 2007 expected coal requirements under contract. Given the geographic diversity of supply, we believe we can meet our expected generation requirements. We lease a fleet of rail cars and have long-term transportation contracts with companies to provide rail and vessel services for delivery of purchased coal to our generating facilities.

Detroit Edison participates in the energy market through MISO. We offer our generation in the market on a day-ahead and real-time basis and bid for power in the market to serve our load. We are a net purchaser of power which supplements our generation capability to meet customer demand during peak cycles.

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Properties

Detroit Edison owns generating plants and facilities that are located in the State of Michigan. Substantially all of our property is subject to the lien of a mortgage.

Generating plants owned and in service as of December 31, 2006 are as follows:

Plant Name	Location by Michigan County	Summer Net Rated Capability (1) (2) (MW)	(%)	Year in Service
Fossil-fueled Steam-Electric				
Belle River (3)	St. Clair	1,026	9.2	1984 and 1985
Conners Creek	Wayne	215	1.9	1951
Greenwood	St. Clair	785	7.1	1979
Harbor Beach	Huron	103	0.9	1968
Marysville	St. Clair	84	0.8	1943 and 1947
Monroe (4)	Monroe	3,115	28.0	1971, 1973 and 1974
River Rouge	Wayne	510	4.6	1957 and 1958
St. Clair	St. Clair	1,415	12.7	1953, 1954, 1959, 1961 and 1969
Trenton Channel	Wayne	730	6.6	1949 and 1968
		7,983	71.8	
Oil or Gas-fueled Peaking Units	Various	1,102	9.9	1966-1971, 1981 and 1999
Nuclear-fueled Steam-Electric Fermi 2 (5)	Monroe	1,111	10.0	1988
Hydroelectric Pumped Storage Ludington (6)	Mason	917	8.3	1973
		11,113	100.0	

(1) Summer net rated capabilities of generating plants in service are based on periodic load tests and are changed depending on operating experience, the physical condition of units, environmental control limitations and customer requirements for steam, which otherwise would

be used for electric generation.

(2) Excludes one oil-fueled unit, St. Clair Unit No. 5 (250 MW), in cold standby status.

(3) The Belle River capability represents Detroit Edison s entitlement to 81.39% of the capacity and energy of the plant. See Note 8.

(4) The Monroe Power Plant provided 38% of Detroit Edison s total 2006 power plant generation.

(5) Fermi 2 has a design electrical rating (net) of 1,150 MW.

(6) Represents Detroit Edison s 49% interest in Ludington with a total capability of 1,872 MW. See Note 8.

Detroit Edison owns and operates 675 distribution substations with a capacity of approximately 33,075,000 kilovolt-amperes (kVA) and approximately 426,700 line transformers with a capacity of approximately 25,883,000 kVA.

Circuit miles of distribution lines owned and in service as of December 31, 2006 are as follows:

Electric Distribution	Circuit Miles	
Operating Voltage-Kilovolts (kV)	Overhead	Underground
4.8 kV to 13.2 kV	28,155	13,747

24 kV	101	690
40 kV	2,323	332
120 kV	70	13
	30,649	14,782

There are numerous interconnections that allow the interchange of electricity between Detroit Edison and electricity providers external to our service area. These interconnections are generally owned and operated by ITC Transmission and connect to neighboring energy companies.

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Regulation

Detroit Edison s business is subject to the regulatory jurisdiction of various agencies, including, but not limited to, the MPSC, the FERC and the NRC. The MPSC issues orders pertaining to rates, recovery of certain costs, including the costs of generating facilities and regulatory assets, conditions of service, accounting and operating-related matters. Detroit Edison s MPSC-approved rates charged to customers have historically been designed to allow for the recovery of costs, plus an authorized rate of return on our investments. The FERC regulates Detroit Edison with respect to financing authorization and wholesale electric activities. The NRC has regulatory jurisdiction over all phases of the operation, construction, licensing and decommissioning of Detroit Edison s nuclear plant operations. We are subject to the requirements of other regulatory agencies with respect to safety, the environment and health.

Since 1996, there have been several important acts, orders, court rulings and legislative actions in the State of Michigan that affect Detroit Edison s operations. In 1996, the MPSC began an initiative designed to give all of Michigan s electric customers access to electricity supplied by other generators and marketers. In 1998, the MPSC authorized the electric Customer Choice program that allowed for a limited number of customers to purchase electricity from suppliers other than their local utility. The local utility continues to transport the electric supply to the customers facilities, thereby retaining distribution margins. The electric Customer Choice program was phased in over a three-year period, with all customers having the option to choose their electric supplier by January 2002.

In 2000, the Michigan Legislature enacted legislation that reduced electric rates by 5% and reaffirmed January 2002 as the date for full implementation of the electric Customer Choice program. This legislation also contained provisions freezing rates through 2003 and preventing rate increases for small business customers through 2004 and for residential customers through 2005. The legislation and an MPSC order issued in 2001 established a methodology to enable Detroit Edison to recover stranded costs related to its generation operations that may not otherwise be recoverable due to electric Customer Choice related lost sales and margins. The legislation also provides for the recovery of the costs associated with the implementation of the electric Customer Choice program. The MPSC has determined that these costs will be treated as regulatory assets. Additionally, the legislation provides for recovery of costs incurred as a result of changes in taxes, laws and other governmental actions including the Clean Air Act.

In 2004, the MPSC issued interim and final rate orders that authorized electric rate increases totaling $374 million, and eliminated transition credits and implemented transition charges for electric Customer Choice customers. The increases were applicable to all customers not subject to a rate cap. The interim order affirmed the resumption of the PSCR mechanism for both capped and uncapped customers, which reduced PSCR revenues. The MPSC also authorized the recovery of approximately $385 million in regulatory assets, including stranded costs. As part of the final order Detroit Edison was ordered to file an application to restructure its electric rates.

In February 2005, Detroit Edison filed a rate restructuring proposal with the MPSC to restructure its electric rates and begin phasing out subsidies within the current pricing structure. In December 2005, the MPSC issued an order that provided for initial steps to improve the current competitive imbalance in Michigan s electric Customer Choice program. The December 2005 order establishes cost-based power supply rates for Detroit Edison s full service customers. Electric Customer Choice participants will pay cost-based distribution rates while Detroit Edison s full service commercial and industrial customers will pay cost-based distribution rates that reflect the cost of the residential rate subsidy. Residential customers continue to pay a subsidized below cost rate for distribution service. These revenue neutral revised rates were effective February 1, 2006. Detroit Edison was also ordered to file a general rate case no later than July 1, 2007, based on 2006 actual results.

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 cited certain changes that had occurred since the November 2004 order in Detroit Edison s last general rate case, or were expected to occur. These changes included: declines in electric Customer Choice program participation, expiration of the residential rate caps, and projected reductions in Detroit Edison operating costs. The show cause filing was to reflect sales, costs and financial conditions that were expected to occur by 2007. On June 1, 2006, Detroit Edison filed its response explaining why its electric rates should not be reduced in 2007. Detroit Edison indicated that it will have a revenue deficiency of approximately $45 million beginning in 2007 due to significant capital investments over the next several years for infrastructure improvements to enhance electric service reliability and for mandated environmental expenditures. The impacts of these investments will be partially offset by efficiency and cost-savings measures that have been initiated. Therefore, Detroit Edison requested that the show cause proceeding allow for rate increase adjustments based on the combined effects of investment expenditures and cost-savings programs. The MPSC denied this request and indicated that a full review of rates will be made in Detroit Edison s next general rate case, which is due to be filed by July 1, 2007. The MPSC issued an order approving a 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 case, rates will be reduced by an additional $26 million, for a total reduction of $79 million. The revenue reduction is net of the recovery of the amortization of the costs associated with the implementation of the Performance Excellence Process, a company wide review of our operations. 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. As part of the settlement agreement, a Choice Incentive Mechanism (CIM) was established with a base level of electric choice sales set at 3,400 GWh.

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 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 to 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.

See Note 6 of the Notes to Consolidated Financial Statements.

Energy Assistance Programs

Energy assistance programs, funded by the federal government and the State of Michigan, remain critical to Detroit Edison s ability to control its uncollectible accounts receivable and collections expenses. Detroit Edison s uncollectible accounts receivable expense is directly affected by the level of government funded assistance its qualifying customers receive. We work continuously with the State of Michigan and others to determine whether the share of funding allocated to our customers is representative of the number of low-income individuals in our service territory.

Strategy and Competition

We strive to be the preferred supplier of electrical generation in southeast Michigan. We can accomplish this goal by working with our customers, communities and regulatory agencies to be a reliable low cost supplier of electricity. To control expenses, we optimize our fuel blends thereby taking maximum advantage of low cost, environmentally friendly low-sulfur western coals. To ensure generation reliability, we continue to invest in our generating plants, which will improve both plant availability and operating efficiencies. We also are making capital investments in areas that have a positive impact on reliability and environmental compliance with the goal of high customer satisfaction.

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Our distribution operations focus on improving reliability, restoration time and the quality of customer service. We seek to lower our operating costs by improving operating efficiencies. Revenues from year to year will vary due to weather conditions, economic factors, regulatory events and other risk factors as discussed in the Risk Factors section that follows.

Effective January 2002, the electric Customer Choice program expanded in Michigan so that all of the Company s electric customers can choose to purchase their electricity from alternative electric suppliers of generation services. Detroit Edison lost 6% of retail sales in 2006, 12% in 2005 and 18% of such sales in 2004 as a result of customers choosing to purchase power from alternative electric suppliers. Customers participating in the electric Customer Choice program consist primarily of industrial and commercial customers whose MPSC-authorized full service rates exceed their cost of service. Customers who elect to purchase their electricity from alternative electric suppliers by participating in the electric Customer Choice program have an unfavorable effect on our financial performance. The effect of lost sales due to the electric Customer Choice program has reduced our need for purchased power, and, when market conditions are favorable we sell power into the wholesale market, in order to lower costs to full service customers.

Detroit Edison acquires transmission services from ITC Transmission. By FERC order, rates charged by ITC Transmission to Detroit Edison were frozen through December 2004. Thereafter, rates became subject to normal FERC regulation. With the MPSC s November 2004 final rate order, transmission costs are recoverable through Detroit Edison s PSCR mechanism.

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 business.

Competition in the regulated electric distribution business is primarily from the on-site generation of industrial customers and from distributed generation applications by industrial and commercial customers. We do not expect significant competition for distribution to any group of customers in the near term.

GAS UTILITY

Description

Our Gas Utility segment consists of MichCon and 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.

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Revenue is generated by providing the following major classes of service: gas sales, end user transportation, intermediate transportation and gas storage.

Revenue by Service

(in Millions)	**2006**	2005	2004
Gas sales	**$ 1,541**	$ 1,860	$ 1,435
End user transportation	**135**	134	119
Intermediate transportation	**69**	58	56
Other	**104**	86	72
Total Revenue	**$ 1,849**	$ 2,138	$ 1,682

Gas sales Includes the sale and delivery of natural gas primarily to residential and small-volume commercial and industrial customers.

End user transportation Gas delivery service provided primarily to large-volume commercial and industrial customers. Additionally, the service is provided to residential customers, and small-volume commercial and industrial customers who have elected to participate in our Customer Choice program. End user transportation customers purchase natural gas directly from producers or brokers and utilize our pipeline network to transport the gas to their facilities or homes.

Intermediate transportation Gas delivery service provided to producers, brokers and other gas companies that own the natural gas, but are not the ultimate consumers. Intermediate transportation customers utilize our gathering and high-pressure transmission system to transport the gas to storage fields, processing plants, pipeline interconnections or other locations.

Other Includes revenues from gas storage, providing appliance maintenance, facility development and other energy-related services.

Our gas sales, end user transportation and intermediate transportation volumes, revenues and net income are impacted by weather. Given the seasonal nature of our business, revenues and net income are concentrated in the first and fourth quarters of the calendar year. By the end of the first quarter, the heating season is largely over, and we typically realize substantially reduced revenues and earnings in the second quarter and losses in the third quarter.

Our operations are not dependent upon a limited number of customers, and the loss of any one or a few customers would not have a material adverse effect on our Gas Utility segment.

Natural Gas Supply

Our gas distribution system has a planned maximum daily send-out capacity of 2.8 Bcf, with approximately 71% of the volume coming from underground storage for 2006. Peak-use requirements are met through utilization of our storage facilities, pipeline transportation capacity, and purchased gas supplies. Because of our geographic diversity of supply and our pipeline transportation and storage capacity, we are able to reliably meet our supply requirements. We believe natural gas supply and pipeline capacity will be sufficiently available to meet market demands in the foreseeable future.

We purchase natural gas supplies in the open market by contracting with producers and marketers, and we maintain a diversified portfolio of natural gas supply contracts. Supplier, producing region, quantity, and available transportation diversify our natural gas supply base. We obtain our natural gas supply from various sources in different geographic areas (Gulf Coast, Mid-Continent, Canada and Michigan) under agreements that vary in both pricing and terms. Gas supply pricing is generally tied to NYMEX and published price indices to approximate current market prices.

Properties

We own distribution, transmission and storage properties that are located in the State of Michigan. Our distribution system includes approximately 19,000 miles of distribution mains, approximately 1,188,000 service lines and approximately 1,321,000 active meters. We own approximately 2,600 miles of transmission lines that deliver natural gas to the distribution districts and interconnect our storage fields with the sources of supply and the market areas.

We own properties relating to four underground natural gas storage fields with an aggregate working gas storage capacity of approximately 124 Bcf. These facilities are important in providing reliable and cost-effective service to our customers. In addition, we sell storage services to third parties. Most of the company s distribution and transmission property are located on property owned by others and used by the company through easements, permits or licenses. Substantially all of our property is subject to the lien of a mortgage.

We are directly connected to interstate pipelines, providing access to most of the major natural gas producing regions in the Gulf Coast, Mid-Continent and Canadian regions.

The company s primary long-term transportation contracts are as follows:

	Availability (MMcf/d)	Contract expiration
Panhandle Eastern Pipeline Company	75	2009
Trunkline Gas Company	10	2009
Viking Gas Transmission Company	50	2010
TransCanada PipeLines Limited	50	2010
Great Lakes Gas Transmission L.P.	30	2011
ANR Pipeline Company	245	2011
Vector Pipeline L.P.	50	2012

We own 840 miles of transportation and gathering pipelines in the northern lower peninsula of Michigan. We lease a portion of our pipeline system to the Vector Pipeline Partnership (an affiliate) through a capital lease arrangement. See Note 13 of the Notes to Consolidated Financial Statements.

Regulation

We are subject to the regulatory jurisdiction of the MPSC, which issues orders pertaining to rates, recovery of certain costs, including the costs of regulatory assets, conditions of service, accounting and other operating-related matters.

We are subject to the requirements of other regulatory agencies with respect to safety, the environment and health.

In the late 1990s, the MPSC began an initiative designed to give all of Michigan s natural gas customers added choices and the opportunity to benefit from lower gas costs resulting from competition. In 1999, the MPSC approved a comprehensive experimental three-year gas Customer Choice program that allowed an increasing number of customers to purchase natural gas from suppliers other than their local utility. In December 2001, the MPSC issued an order that continued the gas Customer Choice program on a permanent and expanding basis. The permanent gas Customer Choice program was phased in over a three-year period, with all customers having the option to choose their gas supplier by April 2004. Since MichCon continues to transport and deliver the gas to the participating customer premises at prices comparable to margins earned on gas sales, customers switching to other suppliers have little impact on MichCon s earnings.

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In April 2005, the MPSC issued a final rate order which increased MichCon s base rates by $61 million annually effective April 29, 2005.

See Note 6 of the Notes to the Consolidated Financial Statements.

Energy Assistance Program

Energy assistance programs, funded by the federal government and the State of Michigan, remain critical to MichCon s ability to control its uncollectible accounts receivable and collections expenses. MichCon s uncollectible accounts receivable expense is directly affected by the level of government funded assistance its qualifying customers receive. We work continuously with the State of Michigan and others to determine whether the share of funding allocated to our customers is representative of the number of low-income individuals in our service territory.

Strategy and Competition

Our strategy is to be a preferred provider of natural gas in Michigan. As a result of more efficient furnaces and appliances, and customer conservation due to high natural gas prices, we expect future sales volumes to remain at current levels or slightly decline. We continue to provide energy-related services that capitalize on our expertise, capabilities and efficient systems. We continue to focus on lowering our operating costs by improving operating efficiencies.

Competition in the gas business primarily involves other natural gas providers, as well as providers of alternative fuels and energy sources. The primary focus of competition for end user transportation is cost and reliability. Some large commercial and industrial customers have the ability to switch to alternative fuel sources such as coal, electricity, oil and steam. If these customers were to choose an alternative fuel source, they would not have a need for our end-user transportation service. In addition, some of these customers could bypass our pipeline system and have their gas delivered directly from an interstate pipeline. We compete against alternative fuel sources by providing competitive pricing and reliable service, supported by our storage capacity.

Our extensive transmission pipeline system has enabled us to market 500 to 600 Bcf annually for intermediate transportation services for Michigan gas producers, marketers, distribution companies and other pipeline companies. We operate in a central geographic location with connections to major Mid-western interstate pipelines that extend throughout the Midwest, eastern United States and eastern Canada.

NON-UTILITY OPERATIONS

Coal and Gas Midstream

Description

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

Coal Transportation and Marketing

Coal Transportation and Marketing provides fuel, transportation, and equipment management services tailored to the individual requirements of each customer. We specialize in minimizing fuel costs and maximizing reliability of supply for energy-intensive customers. Our external customers include electric utilities, merchant power producers, integrated steel mills and large industrial companies with significant energy requirements. Additionally, we participate in coal trading, coal-to-power tolling transactions and the purchase and sale of emissions credits. Coal-to-power tolling is another facet of the trading function, where we buy and arrange transportation of coal to a power plant that has excess generating capacity.

The plant then burns the coal and produces electricity for a fee and returns it via the grid to DTE Energy Trading, which uses the power to fulfill contracts or meet market needs.

(in Millions)	**2006**	2005	2004
Tons of Coal Shipped (1)	**34**	42	40

(1) Includes intercompany transactions of 14 tons, 20 tons, and 18 tons in 2006, 2005, and 2004, respectively.

Pipelines, Processing and Storage

The Pipelines, Processing and Storage business owns and manages a network of natural gas transmission pipelines, storage facilities and gas processing facilities. We have a partnership interest in Vector Pipeline (Vector), an interstate transmission pipeline, which connects Michigan to Chicago and Ontario. We specialize in providing natural gas storage and transportation services in the Midwest and Northeast. We have interests in six processing plants that extract carbon dioxide from Antrim gas production in northern Michigan, making it suitable for transportation to nearby customers. Additionally, we have storage capacity capable of storing up to 75.7 Bcf in natural gas storage fields located in Michigan. The Washington 10 storage facility is a 66 Bcf high deliverability storage field having bi-directional interconnections with Vector Pipeline and MichCon providing customers access to the Chicago, Michigan and Ontario hubs.

Properties

The Pipelines, Processing and Storage business holds the following property:

Property Classification	% Owned	Description	Location
Pipelines			
Vector Pipeline	40%	348-mile pipeline with 1,000 MMcf per day capacity	Midwest
Processing Plants	90%	197 MMcf per day capacity	Northern Michigan
Storage			
Washington 28	50%	9.7 Bcf of storage capacity	Washington Twp, MI
Washington 10	100%	66 Bcf of storage capacity	Washington Twp, MI

The assets of these businesses are complementary with other DTE Energy assets. Pursuant to an operating agreement, MichCon provides physical operations, maintenance and technical support for the Washington 28 and Washington 10 storage facilities.

Strategy and Competition

Our Coal Transportation and Marketing business is one of the leading North American coal marketers. We have a reputation as being an efficient manager of transportation assets. Trends such as railroad and mining consolidation and the lack of certainty in developing new mines by many mining firms could have an impact on how we compete in the future. We will continue to work with suppliers and the railroads to promote secure and competitive access to coal to meet the energy requirements of our customers. We will seek to build our capacity to transport greater amounts of western coal and to expand into coal terminals. 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.

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The Pipelines, Processing and Storage business focuses on asset development opportunities in the Midwest-to-Northeast region to supply natural gas to meet growing demand. We expect much of the growth in the demand for natural gas in the U.S. to occur within the Mid-Atlantic and New England regions. These regions currently lack the pipeline and gas storage infrastructure necessary to deliver gas volumes to meet growing demand. Vector is an interstate pipeline that is filling a large portion of that need, and is complemented by our Michigan storage facilities. Vector received FERC approval in October 2006 for a 200 MMcf per day expansion of long-haul capacity scheduled to be in service by November 2007. In April 2006, the Washington 10 storage facility expanded working capacity from 51.4 to 66 Bcf. 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. Another opportunity is Millennium Pipeline in New York, in which we have a 26.25% interest. In December 2006, Millennium Pipeline received FERC approval for construction and operation and is expected to be in service in late 2008. The Millennium Pipeline will be able to transport up to 525 MMcf per day. The gas supply for Millennium could be sourced from Michigan storage facilities or from Vector Pipeline for consumption in the Northeast U.S.

Unconventional Gas Production

Description

Our Unconventional Gas Production business is engaged in natural gas exploration, development and production primarily within the Antrim shale in the northern lower peninsula of Michigan and the Barnett shale in north Texas. We are an experienced operator in the Antrim shale where we manage one of the industry s largest inventories of proved gas shale reserves. We continue to develop properties in both areas as we explore monetization alternatives. During 2006, we invested $186 million acquiring, testing, developing and producing our Antrim and Barnett shale acreage. In 2006, we added proved reserves of 219 Bcfe in both the Antrim and Barnett shales, resulting in year end total proved reserves of 616 Bcfe. The Barnett and Antrim shale wells yielded 4.1 Bcfe and 21.5 Bcfe of production, respectively, in 2006 for a total of 25.6 Bcfe. Barnett shale leasehold acres increased to 89,808 gross acres (80,530 net of interest of others) after reduction by opportunistic sales of 11,193 acres. We drilled a total of 206 development wells (165.2 net of interest of others) including 64 wells (54.8 net of interest of others) in the Barnett shale acreage with a success rate of 100% in 2006. Included were 4 test wells (3.2 net of interest of others) in unproved areas of the southern portion of our Barnett shale acreage holdings. Production commenced in the Bosque and Hill Counties of Texas in 2006. Testing of Barnett s southern acreage is ongoing and will continue in 2007.

Properties

Unconventional Gas Production owns interests in the following producing wells and acreage as of December 31:

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	2006		2005		2004	
	Gross	**Net**(1)	Gross	Net(1)	Gross	Net (1)
Producing Wells and Acreage						
Producing Wells (2)						
Antrim shale	**2,148**	**1,700**	2,010	1,630	1,878	1,523
Barnett shale	**123**	**110**	65	55	5	1
	2,271	**1,810**	2,075	1,685	1,883	1,524
Developed Lease Acreage (3)						
Antrim shale	**283,007**	**228,232**	278,789	217,643	266,064	213,959
Barnett shale	**17,965**	**16,045**	15,524	14,367	1,262	316
	300,972	**244,277**	294,313	232,010	267,326	214,275
Undeveloped Lease Acreage (4)						
Antrim shale	**80,380**	**66,184**	86,028	73,056	92,328	79,025
Barnett shale	**71,842**	**64,485**	72,280	61,627	54,530	48,541
	152,222	**130,669**	158,308	134,683	146,858	127,566

(1) Excludes the interest of others.

(2) Producing wells is the number of wells that are found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

(3) Developed lease acreage is the number of acres that are allocated or assignable to productive wells or wells capable of production.

(4) Undeveloped lease acreage is the number of acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas and oil regardless of whether such acreage contains proved reserves.

Strategy and Competition

We manage and operate our Antrim and Barnett shale gas properties to maximize returns on investment and increase earnings with the overriding goal of optimizing the cost of producing reserves and adding additional proved reserves.

A long-term fixed price obligation that fixed the price of gas sold at $3.33 for 1.8 Bcf of Antrim shale production expired in 2006. This creates pricing opportunities and we have and will continue to remarket Antrim shale gas production at current higher market rates.

Additional long-term fixed price obligation data for the next five years follows:

	2007	2008	2009	2010	2011
Long-term fixed price obligations					
Antrim					
Volume- Bcf	**17.6**	16.2	15.0	15.0	11.9
Price- $/Mcf	**$3.19**	$3.74	$3.48	$3.59	$3.70
Barnett					
Volume- Bcf	**1.8**	1.3	1.1	0.5	
Price- $/Mcf	**$8.45**	$8.15	$7.73	$7.29	$

Current natural gas prices and successes within the Barnett shale are resulting in more capital being invested into the region. This competition for opportunities, goods and services increases costs. However, our experience in the Antrim shale and our experienced Barnett shale personnel provide an advantage in addressing potential cost increases.

In 2007, we expect to drill 130 to 145 wells in the Antrim shale and 50 to 55 wells in the Barnett shale. Combined investment for both areas is expected to be approximately $150 million to $170 million during 2007. Successful testing on unproved acreage may yield additional significant investment opportunities.

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

Description

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 provided 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 (assuming no phase-out).

Properties

The following are significant Power and Industrial Projects:

Facility	Location	% Owned	Service Type
Steel			
PCI Enterprises, Inc.	River Rouge, MI	100%	Pulverized Coal
DTE Sparrows Point	Sparrows Point, MD	100%	Pulverized Coal
EES Coke Battery, LLC	River Rouge, MI	100%	Metallurgical Coke Supply
Indiana Harbor Coke Co., LP	East Chicago, IN	5%	Metallurgical Coke Supply
Automotive			
DTE Energy Center	Various sites in MI, IN, OH	50%	Electric Distribution, Chiller Water, Waste Water, Compressed Air, Mist and Dust Collectors
DTE Northwind	Detroit, MI	100%	Steam and Chilled Water
DTE Moraine	Moraine, OH	100%	Compressed Air
DTE Tonawanda	Tonawanda, NY	100%	Chilled and Waste Water
Defiance Energy	Defiance, OH	100%	Steam, Cooling Tower Water, Chilled Water, Compressed Air
Heritage	Dearborn, MI	100%	Electric Distribution
Lordstown Energy	Lordstown, OH	100%	Steam, Chilled Water, Compressed Air and Reverse Osmosis Water
Pulp and Paper			
Mobile Energy Services	Mobile, AL	50%	Electric Generation and Steam
Tembec	St. Francisville, LA	100%	Electric Generation and Steam
Airport			
Metro Energy	Romulus, MI	100%	Electricity, Hot and Chilled Water
Pittsburgh	Pittsburg, PA	100%	Hot and Chilled Water
Other Industries			
DTE PetCoke	Vicksburg, MS	100%	Pulverized Petroleum Coke

Pursuant to an operating agreement with PCI Enterprises, Inc., Detroit Edison provides operations and maintenance services for the pulverized coal facility located at Detroit Edison s River Rouge power plant.

Production tax credits, related to one coke battery that expired in 2002, were reinstated for the years 2006 through 2009. The coke battery facilities produce coke that is used in blast furnaces within the steel industry.

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(Dollars in Millions)	**2006**	2005	2004
Production Tax Credits Generated			
Coke Batteries:			
Allocated to DTE Energy	**$ 6**	$ 2	$ 2

Non-Utility Power Generation

Description

We operate peaking, gas-fired and biomass-fired electric generating plants.

Properties

The following are significant properties operated by Non-Utility Power Generation:

Facility	Location	% Owned	Capacity (in MW)
DTE Georgetown	Indianapolis, IN	100%	80
DTE River Rouge (1)	River Rouge, MI	100%	240
Crete Energy Ventures	Crete, IL	50%	320
DTE East China	East China Twp, MI	100%	320
Woodland Biomass	Woodland, CA	99%	25
			985

(1) No longer in service effective September 2006.

Production tax credits are available at one Non-Utility Power Generation facility. The facility produces electricity using renewable resources.

(Dollars in Millions)	**2006**	2005	2004
Production Tax Credits Generated			
Allocated to DTE Energy	**$ 1**	$	$

Landfill Gas Recovery

We develop, own and operate landfill gas recovery systems in the U.S. Landfill gas, a byproduct of solid waste decomposition, is composed of approximately equal portions of methane and carbon dioxide. We develop landfill gas recovery systems that capture the gas and provide local utilities, industry and consumers with an opportunity to use a competitive, renewable source of energy, in addition to providing environmental benefits by reducing greenhouse gas emissions. We also co-own, with the Coal Transportation and Marketing segment, a coal mine methane gathering system and gas processing facility in southern Illinois. This processed methane is sold into the natural gas transmission system. Many of our facilities generate production tax credits that will expire at the end of 2007. Landfill gas recovery has operations in 12 states.

(Dollars in Millions)	**2006**	2005	2004
Landfill Sites	**26**	32	29
Gas Produced (in Bcf)	**22.9**	20.2	23.2
Tax Credits Generated (1)	**$ 5**	$ 8	$ 8

(1)

DTE Energy s portion of tax credits generated.

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Strategy and Competition

Power and Industrial Projects will continue leveraging its extensive energy-related operating experience and project management capability to develop and grow our on-site energy business. We also will continue to pursue opportunities to provide asset management and operations services to third parties.

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

We intend to focus on the following areas for growth:

- Providing operating services to owners of industrial and power plants;
- Acquiring and developing solid fuel-fired power plants and landfill gas recovery facilities; and
- Expanding energy projects.

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

Description

Energy Trading focuses on physical power and gas marketing and trading, 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 provides commodity risk management services to the other businesses within DTE Energy.

Strategy and Competition

Our strategy for our trading business is to deliver value-added services to our customers. We seek to manage this business in a manner consistent with and complementary to the growth of our other business segments. We focus on physical marketing and the optimization of our portfolio of energy assets. We compete with electric and gas marketers, traders, utilities and other energy providers. We have risk management and credit processes to monitor and mitigate risk. We are exploring strategic options for the energy trading business.

Synthetic Fuel

Description

Synfuel plants chemically change coal and waste coal into a synthetic fuel as determined under the Internal Revenue Code. The synthetic fuel process involves chemically modifying and binding particles of coal to produce a fuel that is used for power generation and coke production. 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) and is reduced, or eliminated, 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

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at each of the nine synfuel facilities due to these amended commercial agreements and declines in the level of oil prices.

Since 2002, we have sold interests in all nine of our synfuel plants, ranging from a 49%-99% share in each, or approximately 91% of our total production capacity. We consolidate these projects due to our controlling influence and continuing involvement.

(Dollars in Millions)	**2006**	2005	2004
Production Tax Credits Generated			
Synfuel Plants			
Allocated to DTE Energy	**$ 23**	$ 45	$ 29
Allocated to partners	**260**	562	411
	$ 283	$ 607	$ 440

Properties

The following are our synthetic fuels projects:

Facility	Location	% Owned	Industry Served
DTE Red Mountain, LLC	Tarrant, AL	51%	Foundry Coke/Steel
DTE Belews Creek, LLC	Belews Creek, NC	1%	Utility
DTE Utah Synfuels, LLC	Price, UT	1%	Industrial/Utility
DTE Indy Coke, LLC	Moundsville, WV	1%	Utility
DTE Clover, LLC	Bledsoe, KY	5%	Utility
DTE Smith Branch, LLC	Pineville, WV	1%	Steel/Export
DTE River Hill, LLC	Clover, VA	51%	Utility
DTE Buckeye, LLC (2 plants)	Cheshire, OH	1%	Utility

Strategy and Competition

Due to our hedging strategy implemented in 2006, we expect to continue to operate the synfuel plants through December 31, 2007, when synfuel-related production tax credits expire.

CORPORATE & OTHER

Description

Corporate & Other includes various corporate staff functions. Because these functions support the entire Company, their costs are 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 investments in energy-related companies and funds.

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Strategy and Competition

Our energy-related investment strategy is to create a profitable portfolio by investing in companies or funds that facilitate the creation of new businesses, expand growth opportunities for existing businesses or enable performance improvements in our existing businesses.

ENVIRONMENTAL MATTERS

We are subject to extensive environmental regulation. Additional costs may result as the effects of various substances on the environment are studied and governmental regulations are developed and implemented. We expect to continue recovering environmental costs related to utility operations through rates charged to our customers. The following table summarizes our estimated significant future environmental expenditures:

(in Millions)	Electric	Gas	Non-Utility	Total
Air	$ 2,185	$	$	$ 2,185
Water	53		14	67
MGP Sites	4	41		45
Other Clean Up Sites	12	1		13
Estimated total future expenditures	$ 2,254	$ 42	$ 14	$ 2,310
Estimated 2007 expenditures	$ 234	$ 5	$ 14	$ 253

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. The cost to address environmental air issues is estimated through 2018.

Water In response to an EPA regulation, Detroit Edison is required to examine alternatives for reducing the environmental impacts of the cooling water intake structures at several of its facilities. Based on the results of studies to be conducted over the next one to two years, Detroit Edison may be required to perform some mitigation activities, including, the possible installation of additional control technologies to reduce the environmental impact of the intake structures. However, a recent court decision remanded back to the EPA several provisions of the federal regulation resulting in a delay in complying with the regulation.

MGP 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. The facilities, which produced gas for heating and other uses, have been designated as MGP sites. Gas Utility owns, or previously owned, fifteen such former MGP sites. In addition to the MGP sites, the company is also in the process of cleaning up other contaminated sites. As a result of these determinations, we have recorded liabilities related to these sites. Cleanup activities associated with these sites will be conducted over the next several years.

Detroit Edison conducted remedial investigations at contaminated sites, including two MGP sites, the area surrounding an ash landfill and several underground and aboveground storage tank locations. The findings of these investigations indicated that the estimated cost to remediate these sites is expected to be incurred over the next several years. In addition, Detroit Edison will be making capital improvements to the ash landfill in 2007.

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Non-utility 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.
Greater details on environmental issues are provided in the following Notes to Consolidated Financial Statements:

Note	Title
6	Regulatory Matters
7	Nuclear Operations

EMPLOYEES
The following table shows our employees as of December 31, 2006:

	Represented	Non-represented	Total
Detroit Edison	3,724	3,493	7,217
MichCon	1,386	707	2,093
Other	308	909	1,217
Total	5,418	5,109	10,527

There are several bargaining units for our represented employees. Approximately 3,245 of our represented employees are under contracts that expire in June 2007 and 970 employees are under contracts that expire in October 2007. The contracts of the remaining represented employees expire at various dates in 2008 and 2009.

EXECUTIVE OFFICERS OF DTE ENERGY

Name	**Age (1)**	**Present Position**	**Present Position Held Since**
Anthony F. Earley, Jr.	57	Chairman of the Board and Chief Executive Officer	8-1-98
Gerard M. Anderson	48	Chief Operating Officer and	10-31-05
		President	6-23-04
Stephen E. Ewing (2)	62	Vice Chairman, DTE Energy	10-31-05
		President and Chief Operating Officer, MichCon	4-28-05
Robert J. Buckler	57	President and Chief Operating Officer, Detroit Edison	10-31-05
		Group President, DTE Energy	5-31-05
David E. Meador	49	Executive Vice President and Chief Financial Officer	6-23-04
Lynne Ellyn	55	Senior Vice President and Chief Information Officer	12-31-01
Paul C. Hillegonds	57	Senior Vice President	5-16-05
Ron A. May	55	Senior Vice President	1-22-04
Bruce D. Peterson	50	Senior Vice President and General Counsel	6-25-02
Gerardo Norcia	44	Executive Vice President, MichCon	10-31-05
Larry E. Steward	54	Vice President	1-15-01
Peter B. Oleksiak	40	Vice President and Controller	12-5-05
Sandra K. Ennis	50	Corporate Secretary	8-4-05

(1) As of December 31, 2006

(2)

Retired from the company effective December 31, 2006

Under our Bylaws, the officers of DTE Energy are elected annually by the Board of Directors at a meeting held for such purpose, each to serve until the next annual meeting of directors or until their respective successors are chosen and qualified. With the exception of Messrs. Hillegonds, Peterson and

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Norcia, all of the above officers have been employed by DTE Energy in one or more management capacities during the past five years.

Paul C. Hillegonds was elected Senior Vice President effective May 16, 2005. Mr. Hillegonds was president of Detroit Renaissance for eight years prior to joining DTE Energy.

Bruce D. Peterson was elected Senior Vice President and General Counsel on June 25, 2002. Mr. Peterson was a partner with Hunton & Williams in Washington, D.C. prior to joining DTE Energy.

Gerardo Norcia was elected Executive Vice President, MichCon on October 31, 2005. Mr. Norcia was President, DTE Gas Storage, Pipelines and Processing since joining DTE Energy on November 4, 2002. He was a vice president of Union Gas prior to joining DTE Energy.

Pursuant to Article VI of our Articles of Incorporation, directors of DTE Energy will not be personally liable to the Company or its shareholders in the performance of their duties to the full extent permitted by law.

Article VII of our Articles of Incorporation provides that each current or former director or officer of DTE Energy, or each current and former employee or agent of the Company or a director, officer, employee or agent of another corporation, partnership, joint venture, trust or other enterprise (including the heirs, executors, administrators or estate of such person), shall be indemnified by the Company to the full extent permitted by the Michigan Business Corporation Act or any other applicable laws as presently or hereafter in effect. In addition, we have entered into indemnification agreements with all of our officers and directors; these agreements set forth procedures for claims for indemnification as well as contractually obligating us to provide indemnification to the maximum extent permitted by law.

We and our directors and officers in their capacities as such are insured against liability for alleged wrongful acts (to the extent defined) under eight insurance policies providing aggregate coverage in the amount of $185 million.

Item 1A. Company Risk Factors

There are various risks associated with the operations of DTE Energy s utility and non-utility businesses. To provide a framework to understand the operating environment of DTE Energy, we are providing a brief explanation of the more significant risks associated with our businesses. Although we have tried to identify and discuss key risk factors, others could emerge in the future. Each of the following risks could affect our performance.

Our ability to utilize production tax credits may be limited. To reduce U.S. dependence on imported oil, the Internal Revenue Code provides production tax credits as an incentive for taxpayers to produce fuels from alternative sources. We have generated production tax credits from the synfuel, coke battery, landfill gas recovery and gas production operations. We have received favorable private letter rulings on all of the synfuel facilities. All production tax credits taken after 2003 are subject to audit by the Internal Revenue Service (IRS). If our production tax credits were disallowed in whole or in part as a result of an IRS audit, there could be additional tax liabilities owed for previously recognized tax credits that could significantly impact our earnings and cash flows. The value of future credits generated may be affected by potential legislation. Moreover, the opportunity to earn additional production tax credits related to the generation of synfuels and recovery of landfill gas will expire at the end of 2007. The combination of IRS audits of production tax credits, supply and demand for investment in credit producing activities and potential legislation could have an impact on our earnings and cash flows. We have also provided certain guarantees and indemnities in conjunction with the sales of interests in the synfuel facilities.

This incentive provided by production tax credits is not deemed necessary if the price of oil increases and provides significant market incentives for the production of these fuels. As such, the tax credit in a given year is reduced if the Reference Price of oil within that year exceeds a threshold price. The Reference Price of a barrel of oil is an estimate of the annual average wellhead price per barrel for domestic crude oil. We project the yearly average wellhead price per barrel of oil for the year to be approximately $6 lower than the NYMEX price for light, sweet crude oil. The threshold price at which the credit begins to be reduced was set in 1980 and is adjusted annually for inflation. For 2006, we estimate the threshold price at which the tax credit would begin to be reduced is $55 per barrel and would be completely phased out if the Reference Price reached $69 per barrel. As of December 31, 2006, the average NYMEX daily closing price of a barrel of oil was approximately $66 for 2006, equating to an estimated Reference Price of $60, which we estimate to be within the phase-out range. To mitigate the effect of a potential phase out and minimize operating losses, on May 12, 2006 we idled production at all nine of the synfuel facilities. The decision to idle synfuel production was driven by the level and volatility of oil prices at that time. Beginning September 5, 2006 through October 4, 2006, we resumed production at each of the nine synfuel facilities due to declines in the level of oil prices.

Our estimates of gas reserves are subject to change. We cannot assure that our estimates of our Antrim and Barnett gas reserves are accurate. Estimates of proved gas reserves and the future net cash flows attributable to those reserves are prepared by independent engineers. There are numerous uncertainties inherent in estimating quantities of proved gas reserves and cash flows attributable to such reserves, including factors beyond our control and that of our engineers. Reserve engineering is a subjective process of estimating underground accumulations of gas that cannot be measured in an exact manner. The accuracy of an estimate of quantities of reserves, or of cash flows attributable to such reserves, is a function of the available data, assumptions regarding expenditures for future development and exploration activities, and of engineering and geological interpretation and judgment. Additionally, reserves and future cash flows may be subject to material downward or upward revisions, based upon production history, development and exploration activities and prices of gas. Actual future production, revenue, taxes, development expenditures, operating expenses, underlying information, quantities of recoverable reserves and the value of cash flows from such reserves may vary significantly from the assumptions and underlying information we used. In addition, different reserve engineers may make different estimates of reserves and cash flows based on the same available data.

Michigan s electric Customer Choice program is negatively impacting our financial performance. The electric Customer Choice program, as originally contemplated in Michigan, anticipated an eventual transition to a totally deregulated and competitive environment where customers would be charged market-based rates for their electricity. The State of Michigan currently experiences a hybrid market, where the MPSC continues to regulate electric rates for our customers, while alternative electric suppliers charge market-based rates. In addition, such regulated electric rates for certain groups of our customers exceed the cost of service to those customers. Due to distorted pricing mechanisms during the initial implementation period of electric Customer Choice, many commercial customers chose alternative electric suppliers. Recent MPSC rate orders have removed some of the pricing disparity. Recent higher wholesale electric prices have also resulted in some former electric Customer Choice customers migrating back to Detroit Edison for electric generation service. Even with the electric Customer Choice-related rate relief received in Detroit Edison s 2004 and 2005 orders, there continues to be considerable financial risk associated with the electric Customer Choice program. Electric Customer Choice migration is sensitive to market price and bundled electric service price increases. The hybrid market in Michigan also causes uncertainity as it relates to investment in new generating capacity.

Weather significantly affects operations. Deviations from normal hot and cold weather conditions affect our earnings and cash flow. Mild temperatures can result in decreased utilization of our assets, lowering income and cash flow. Damage due to ice storms, tornadoes, or high winds can damage our infrastructure and require us to perform emergency repairs and incur material unplanned expenses. The expenses of storm restoration efforts may not be recoverable through the regulatory process.

We are subject to rate regulation. Electric and gas rates for our utilities are set by the MPSC and the FERC and cannot be increased without regulatory authorization. We may be impacted by new regulations or interpretations by the MPSC, the FERC or other regulatory bodies. New legislation, regulations or interpretations could change how our business operates, impact our ability to recover costs through rate increases or require us to incur additional expenses.

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Our non-utility operations may not perform to our expectations. We rely on our non-utility operations for a significant portion of our earnings. If our current and contemplated non-utility investments do not perform at expected levels, we could experience diminished earnings potential and a corresponding decline in our shareholder value.

We rely on cash flows from subsidiaries. Cash flows from our utility and non-utility subsidiaries are required to pay interest expenses and dividends on DTE Energy debt and securities. Should a major subsidiary not be able to pay dividends or transfer cash flows to DTE Energy, our ability to pay interest and dividends would be restricted.

Adverse changes in our credit ratings may negatively affect us. Increased scrutiny of the energy industry and regulatory changes, as well as changes in our economic performance, could result in credit agencies reexamining our credit rating. While credit ratings reflect the opinions of the credit agencies issuing such ratings and may not necessarily reflect actual performance, a downgrade in our credit rating could restrict or discontinue our ability to access capital markets at attractive rates and increase our borrowing costs. In addition, a reduction in credit rating may require us to post collateral related to various trading contracts, which would impact our liquidity.

Our ability to access capital markets at attractive interest rates is important. Our ability to access capital markets is important to operate our businesses. Heightened concerns about the energy industry, the level of borrowing by other energy companies and the market as a whole could limit our access to capital markets. Changes in interest rates could increase our borrowing costs and negatively impact our financial performance.

Regional and national economic conditions can have an unfavorable impact on us. Our businesses follow the economic cycles of the customers we serve. Should national or regional economic conditions decline, reduced volumes of electricity and gas we supply will result in decreased earnings and cash flow. Economic conditions in our service territory also impact our collections of accounts receivable and financial results.

Environmental laws and liability may be costly. We are subject to numerous environmental regulations. These regulations govern air emissions, water quality, wastewater discharge, and disposal of solid and hazardous waste. Compliance with these regulations can significantly increase capital spending, operating expenses and plant down times. These laws and regulations require us to seek a variety of environmental licenses, permits, inspections and other regulatory approvals. We may also incur liabilities as a result of potential future requirements to address the climate change issue. The regulatory environment is subject to significant change; therefore, we cannot predict how future issues may impact the company.

Additionally, we may become a responsible party for environmental clean up at sites identified by a regulatory body. We cannot predict with certainty the amount and timing of future expenditures related to environmental matters because of the difficulty of estimating clean up costs. There is also uncertainty in quantifying liabilities under environmental laws that impose joint and several liability on potentially responsible parties.

Since there can be no assurances that environmental costs may be recovered through the regulatory process, our financial performance may be negatively impacted as a result of environmental matters.

Operation of a nuclear facility subjects us to risk. Ownership of an operating nuclear generating plant subjects us to significant additional risks. These risks include among others, plant security, environmental regulation and remediation, and operational factors that can significantly impact the performance and cost of operating a nuclear facility. While we maintain insurance for various nuclear-related risks, there can be no assurances that such insurance will be sufficient to cover our costs in the event of an accident or business interruption at our nuclear generating plant, which may affect our financial performance.

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The supply and price of fuel and other commodities may impact our financial results. We are dependent on coal for much of our electrical generating capacity. Price fluctuations and fuel supply disruptions could have a negative impact on our ability to profitably generate electricity. Our access to natural gas supplies is critical to ensure reliability of service for our utility gas customers. We have hedging strategies in place to mitigate negative fluctuations in commodity supply prices, but there can be no assurances that our financial performance will not be negatively impacted by price fluctuations. The price of natural gas also impacts the market for our non-utility businesses that compete with utilities and alternative electric suppliers.

A work interruption may adversely affect us. Unions represent approximately 5,400 of our employees. A union choosing to strike as a negotiating tactic would have an impact on our business. We are unable to predict the effects a work stoppage would have on our costs of operation and financial performance.

Unplanned power plant outages may be costly. Unforeseen maintenance may be required to safely produce electricity or comply with environmental regulations. As a result of unforeseen maintenance, we may be required to make spot market purchases of electricity that exceed our costs of generation. Our financial performance may be negatively affected if we are unable to recover such increased costs.

Michigan tax reform may be costly. The State of Michigan is experiencing a revenue shortfall. We are a significant taxpayer in the State of Michigan. The legislature is expected to change the tax laws in 2007, and we could face increased taxes.

We may not be fully covered by insurance. While we have a comprehensive insurance program in place to provide coverage for various types of risks, catastrophic damage as a result of acts of God, terrorism, war or a combination of significant unforeseen events could impact our operations and economic losses might not be covered in full by insurance.

Terrorism could affect our business. Damage to downstream infrastructure or our own assets by terrorism would impact our operations. We have increased security as a result of past events and further security increases are possible.

Our participation in energy trading markets subjects us to risk. Events in the energy trading industry have increased the level of scrutiny on the energy trading business and the energy industry as a whole. In certain situations we may also be required to post collateral to support trading operations. We have established risk policies to manage the business.

Failure to successfully implement new processes and information systems could interrupt our operations. Our businesses depend on numerous information systems for operations and financial information and billings. We are in the midst of a multi-year Company-wide initiative to improve existing processes and implement new core information systems. We launched the first phase of our Enterprise Business Systems project in 2005. Additional phases of implementation are planned for 2007. Failure to successfully implement new processes and new core information systems could interrupt our operations.

Benefits of the Performance Excellence Process to the Company could be less than the Company has projected. In 2005, we initiated a company-wide review of our operations called the Performance Excellence Process with the overarching goal to become more competitive by reducing costs, eliminating waste and optimizing business processes while improving customer service. Actual results achieved through this process could be less than the Company s expectations.

The inability to consummate any strategic transactions for our non-utility operations could affect our expected cash flows. 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. If we are not able to consummate any strategic transactions on favorable terms or timing, our expected cash flows could be lower than anticipated.

Item 1B. Unresolved Staff Comments

None.

Item 3. Legal Proceedings

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

For additional discussion on legal matters, see the following Notes to Consolidated Financial Statements:

Note	Title
6	Regulatory Matters
7	Nuclear Operations
15	Commitments and Contingencies

Item 4. Submission of Matters to a Vote of Security Holders

We did not submit any matters to a vote of security holders in the fourth quarter of 2006.

Part II

Item 5. Market for Registrant s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Our common stock is listed on the New York Stock Exchange, which is the principal market for such stock. The following table indicates the reported high and low sales prices of our common stock on the Composite Tape of the New York Stock Exchange and dividends paid per share for each quarterly period during the past two years:

Year	Quarter	High	Low	Dividends Paid Per Share
2006	**First**	**$44.23**	**$40.00**	**$0.515**
	Second	**$41.91**	**$38.77**	**$0.515**
	Third	**$43.63**	**$40.26**	**$0.515**
	Fourth	**$49.24**	**$41.37**	**$0.530**
2005	First	$46.99	$42.40	$0.515
	Second	$48.31	$44.40	$0.515
	Third	$48.22	$44.11	$0.515
	Fourth	$46.65	$41.39	$0.515

At December 31, 2006, there were 177,138,060 shares of our common stock outstanding. These shares were held by a total of 89,984 shareholders of record.

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Our Bylaws nullify Chapter 7B of the Michigan Business Corporation Act (Act). This Act regulates shareholder rights when an individual s stock ownership reaches 20% of a Michigan corporation s outstanding shares. A shareholder seeking control of the Company cannot require our Board of Directors to call a meeting to vote on issues related to corporate control within 10 days, as stipulated by the Act. See Note 10 of the Notes to Consolidated Financial Statements for information concerning the Shareholders Rights Agreement.

We paid cash dividends on our common stock of $365 million in 2006, $360 million in 2005, and $354 million in 2004. The amount of future dividends will depend on our earnings, cash flows, financial condition and other factors that are periodically reviewed by our Board of Directors. Although there can be no assurances, we anticipate paying dividends for the foreseeable future. In fourth quarter of 2006, we announced a quarterly dividend increase, effective January 15, 2007, from $0.515 per share to $0.53 per share.

All of our equity compensation plans that provide for the annual awarding of stock-based compensation have been approved by shareholders. See Note 17 of the Notes to Consolidated Financial Statements for additional detail.

See the following table for information as of December 31, 2006.

	Number of securities to be issued upon exercise of outstanding options	Weighted-average exercise price of outstanding options	Number of securities remaining available for future issuance under equity compensation plans
Plans approved by shareholders	5,667,197	$ 41.60	7,654,802

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UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS
Purchases of Equity Securities by the Issuer and Affiliated Purchasers
The following table provides information about Company purchases of equity securities that are registered by the Company pursuant to Section 12 of the Exchange Act for the year ended December 31, 2006:

Period	Total Number of Shares Purchased (1)	Average Price Paid Per Share (1)	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs (2)	Average Price Paid Per Share (2)	Maximum Dollar Value that May Yet Be Purchased Under the Plans or Programs (2)
01/01/06 01/31/06					$ 700,000,000
02/01/06 02/28/06					700,000,000
03/01/06 03/31/06	199,555	42.70			700,000,000
04/01/06 04/30/06	37,525	40.65			700,000,000
05/01/06 05/31/06					700,000,000
06/01/06 06/30/06	6,725	41.13			700,000,000
07/01/06 07/31/06	1,000	40.83			700,000,000
08/01/06 08/31/06					700,000,000
09/01/06 09/30/06	1,500	40.71			700,000,000
10/01/06 10/31/06					700,000,000
11/01/06 11/30/06					700,000,000
12/01/06 12/31/06	36,250	49.10	1,000,000	48.47	651,506,040
Total	282,555	43.19	1,000,000		

(1) Represents shares of common stock purchased on the open market to provide shares to

participants under various employee compensation and incentive programs. These purchases were not made pursuant to a publicly announced plan or program.

(2) In January 2005, the DTE Energy Board 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 asset monetizations, cash flows and other investment opportunities.

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Item 6. Selected Financial Data

The following selected financial data should be read in conjunction with the accompanying Management s Discussion and Analysis and Notes to the Consolidated Financial Statements.

(in Millions, except per share amounts)	**2006**	2005	2004	2003	2002
Operating Revenues	**$ 9,022**	$ 9,021	$ 7,069	$ 6,999	$ 6,680
Net Income (Loss)					
Total from continuing operations	**$ 437**	$ 577	$ 464	$ 475	$ 598
Discontinued operations	**(5)**	(37)	(33)	73	34
Cumulative effect of accounting changes	**1**	(3)		(27)	
Net Income	**$ 433**	$ 537	$ 431	$ 521	$ 632
Diluted Earnings Per Share					
Total from continuing operations	**$ 2.45**	$ 3.28	$ 2.68	$ 2.83	$ 3.62
Discontinued operations	**(.03)**	(.21)	(.19)	.42	.21
Cumulative effect of accounting changes	**.01**	(.02)		(.16)	
Diluted Earnings Per Share	**$ 2.43**	$ 3.05	$ 2.49	$ 3.09	$ 3.83
Financial Information					
Dividends declared per share of common stock	**$ 2.075**	$ 2.06	$ 2.06	$ 2.06	$ 2.06
Total assets	**$ 23,785**	$ 23,335	$ 21,297	$ 20,753	$ 19,985
Long-term debt, including capital leases	**$ 7,474**	$ 7,080	$ 7,606	$ 7,669	$ 7,803
Shareholders equity	**$ 5,849**	$ 5,769	$ 5,548	$ 5,287	$ 4,565

Item 7. 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 Detroit Edison and 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 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 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 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.

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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.

Michigan Antrim Shale

	2006	2005	2004
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.

Texas Barnett Shale

	2006	2005	2004
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.

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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.

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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 CTA 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.

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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 the nine synfuel plants.

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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:

Increase (Decrease) in Gross Margin Components Compared to Prior Year

(in Millions)	**2006**	2005
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

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Power Generated and Purchased						
(in Thousands of MWh)	**2006**		2005		2004	
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 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

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by an adjustment we recorded in the first quarter of 2005 related to an April 2005 MPSC order in our 2002 GCR reconciliation case that disallowed $26 million representing unbilled revenues at December 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

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 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

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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.

Operation 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 ge