UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2003

Commission file number 1-11607

DTE ENERGY COMPANY

(Exact name of registrant as specified in its charter)

Michigan (State or other jurisdiction of incorporation or organization)	**38-3217752** (I.R.S. Employer Identification No.)
2000 2nd Avenue, Detroit, Michigan (Address of principal executive offices)	**48226-1279** (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 and Chicago Stock Exchanges
8.75% Equity Security Units	New York Stock Exchange
7.8% Trust 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.

Securities registered pursuant to Section 12(g) of the Act:

None

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 [X] No [ ]

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 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. **[ ]**

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act). **Yes [X] No [ ]**

Based on the closing price on June 30, 2003, our most recently completed second quarter, the aggregate market value of our Common Stock held by non-affiliates was $6.2 billion.

At January 31, 2004, 168,849,506 shares of DTE Energy's Common Stock, substantially all held by non-affiliates, were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Certain information in DTE Energy Company’s definitive Proxy Statement for its 2004 Annual Meeting of Common Shareholders to be held April 29, 2004, 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.

TABLE OF CONTENTS

DTE Energy Company

Annual Report on Form 10-K
Year Ended December 31, 2003

Table of Contents

Definitions

Company	DTE Energy Company and subsidiary companies
Coke and Coke Battery	Raw coal is heated to high temperatures in ovens to drive off 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.
Customer Choice	Choice programs are statewide initiatives giving customers in Michigan the option to choose alternative suppliers for electricity and gas.
Detroit Edison	The Detroit Edison Company (a wholly owned subsidiary of DTE Energy Company) and subsidiary companies
Distributed Generation	Electric energy produced at or close to the point of use, in contrast to central station generation that generally produces electricity at large power plants and transmits and distributes power over long distances. Distributed generation includes fuel cells, small gas turbine engines called micro- and mini-turbines, and other devices capable of producing up to two megawatts of power.
DTE Energy	DTE Energy Company, the parent of Detroit Edison and Enterprises
Enterprises	DTE Enterprises Inc. (successor to MCN Energy) and subsidiary companies
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
GCR	A gas cost recovery mechanism authorized by the MPSC that was reinstated by MichCon in January 2002, 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)
MCN Energy	MCN Energy Group Inc. and subsidiary companies that were merged into Enterprises
MichCon	Michigan Consolidated Gas Company and subsidiary companies
MPSC	Michigan Public Service Commission
Non-regulated Subsidiary	A subsidiary whose conditions of service, prices of goods and services and other operating related matters are not regulated by the MPSC or the FERC
NRC	Nuclear Regulatory Commission
PSCR	A power supply cost recovery mechanism authorized by the MPSC that allowed Detroit Edison to recover through rates its fuel, fuel-related and purchased power expenses. The clause was suspended under Michigan's restructuring legislation signed into law June 5, 2000, which lowered and froze electric customer rates. The clause was reinstated by the MPSC effective January 1, 2004.
Section 29 tax credits	Tax credits as authorized under Section 29 of the Internal Revenue Code that are designed to stimulate investment in and development of alternate fuel sources.

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 are not expected to be recoverable if customers switch to alternative suppliers of electricity and gas.
Synfuels	The fuel produced through a process involving chemically modifying and binding particles of coal. Synfuels are used for power generation and coke production.

Units of Measurement

Bcf	Billion cubic feet of gas
Bcfe	Conversion metric of natural gas, the ratio as defined by the Securities and Exchange Commission of 6 Mcf of gas to 1 barrel of oil.
gWh	Gigawatthour of electricity
kWh	Kilowatthour of electricity
Mcf	Thousand cubic feet of gas
MMcf	Million cubic feet of gas
MW	Megawatt of electricity
MWh	Megawatthour of electricity

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 contemplated, projected, estimated or budgeted in such forward-looking statements. There are many factors that may impact forward-looking statements including, but not limited to, the following:

- the effects of weather and other natural phenomena on operations and sales to customers;
- economic climate and growth in the geographic areas where we do business;
- environmental issues, including changes in the climate, and regulations;
- nuclear regulations and risks associated with nuclear operations;
- ability to utilize Section 29 tax credits or sell interests in facilities producing such credits;
- implementation of electric and gas Customer Choice programs;
- implementation of electric and gas utility restructuring in Michigan;
- employee relations;
- unplanned outages;
- access to capital markets and capital market conditions and 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 of fuel, purchased power and natural gas;
- effects of competition;
- impact of FERC and MPSC proceedings and regulations;
- contributions to earnings by non-regulated businesses;
- changes in federal or state tax laws and their interpretations, including the code, regulations, rulings, court proceedings and audits;
- ability to recover costs through rate increases;
- insurance;
- the cost of protecting assets against or damage due to terrorism; and
- changes in accounting standards and financial reporting regulations.

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 statement speaks 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.

Part I

Items 1. & 2. Business & Properties

GENERAL

In 1995, DTE Energy incorporated in the state of Michigan. Our regulated operations consist primarily of Detroit Edison and MichCon. We also have numerous non-regulated subsidiaries engaged in energy marketing and trading, energy services, and various other electricity, coal and gas related businesses. DTE Energy is an exempt holding company under the Public Utility Holding Company Act (PUHCA) of 1935, except Section 9 (a) (2) that relates to the acquisition of securities of public utility companies and Section 33 that relates to the acquisition of foreign (non-U.S.) utility companies.

Detroit Edison is a Michigan corporation organized in 1903. Detroit Edison is a public utility subject to regulation by the MPSC and FERC and is engaged in the generation, purchase, distribution and sale of electric energy to 2.1 million customers in a 7,600 square mile area in southeastern Michigan.

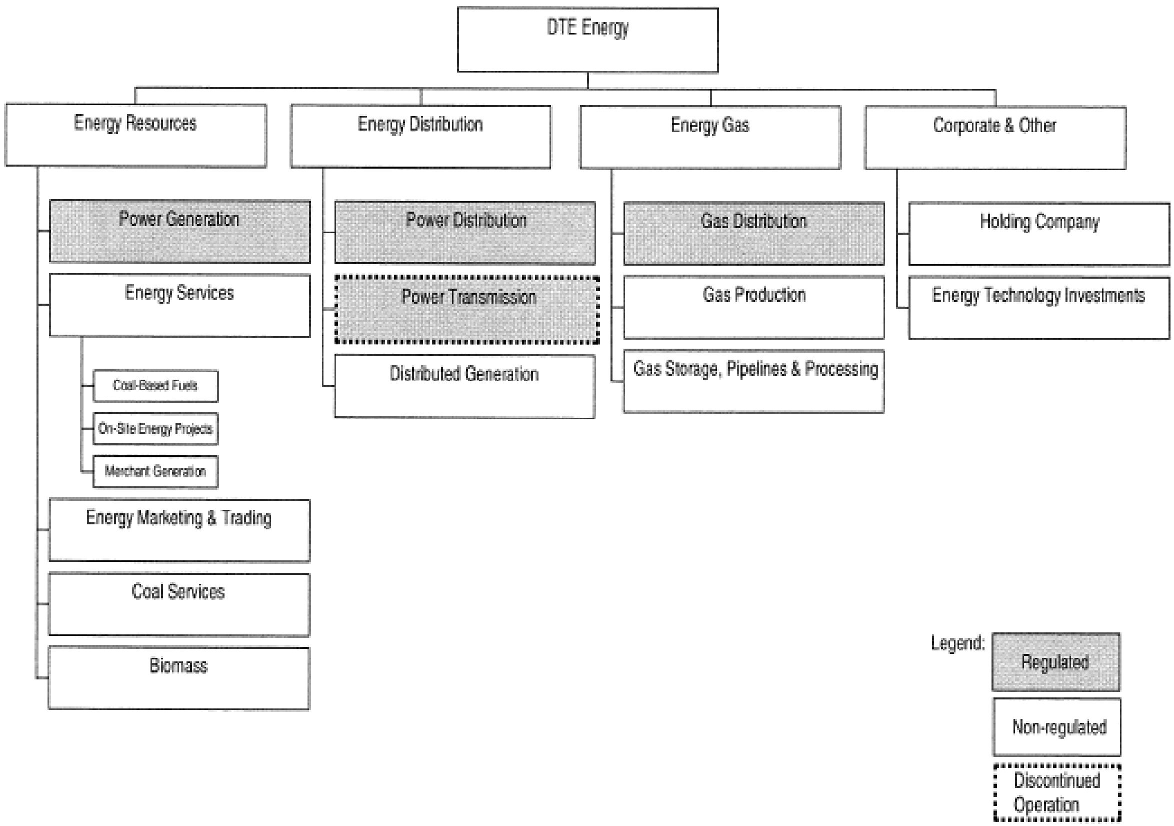
MichCon is a Michigan corporation organized in 1898. MichCon became an indirect wholly owned subsidiary of DTE Energy in conjunction with the acquisition of MCN Energy (which was subsequently merged into Enterprises), which was completed on May 31, 2001. See Note 3 for a further discussion of the MCN Energy acquisition. MichCon 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 1.2 million customers in a 14,700 square mile area throughout Michigan.

In February 2003, we sold the International Transmission Company (ITC), a FERC regulated transmission company. See Note 3 for a further discussion of the ITC sale and its presentation as a discontinued operation.

Our website is www.dteenergy.com. Available free of charge on our website is information such as previously filed reports with the SEC, press releases and other informational resources regarding DTE Energy and our subsidiaries. The information on our website is updated as soon as reasonably practicable. 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. Additionally, 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” or “Company” are to DTE Energy and its subsidiaries, collectively.

We operate our businesses through three strategic business units (Energy Resources, Energy Distribution and Energy Gas). The balance of our business consists of Corporate & Other. Based on this structure, we set strategic goals, allocate resources and evaluate performance. Each business unit has regulated and non-regulated operations, and contributed to DTE Energy's 2003 diluted earnings per share of $3.09. See Note 16 - Segment and Related Information, for financial information by segment for the last three years. A discussion of each business follows.



ENERGY RESOURCES

Power Generation

Description

Power Generation comprises our regulated power generation business and plants within Detroit Edison. These plants are regulated by numerous federal and state governmental agencies, including the MPSC, the NRC and the EPA. Electricity is generated from Detroit Edison's numerous fossil plants, its hydroelectric pumped storage plant and its nuclear plant, and purchased from electricity generators, suppliers and wholesalers. The electricity we produce and purchase is sold to four major classes of customers: residential, commercial, industrial and wholesale, principally throughout Michigan, the Midwest and Ontario, Canada.

Weather, economic factors 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. Power generation sales are made to a diverse base of customers in both type and number; sales levels are not dependent on any small market segment. However, due to residential rate subsidization, less than 1% of the customers constitute approximately 80% of the power generation margin. Additionally, business customers who have elected to participate in the electric Customer Choice program are having a significant unfavorable effect on our financial performance.

Our power is generated from a variety of fuels and is supplemented with market purchases. The table below details our energy supply mix and average cost per unit:

(in Thousands of MWh)	2003		2002		2001	
Power Generated and Purchased						
Power Plant Generation						
Fossil						
Coal	**37,408**	**71%**	37,381	64%	38,424	69%
Natural Gas & Other	**644**	**1**	1,636	3	1,287	2
Nuclear (Fermi 2)	**8,114**	**16**	9,301	16	8,555	16
	46,166	**88**	48,318	83	48,266	87
Purchased Power	**6,354**	**12**	9,807	17	7,482	13
System Output	**52,520**	**100%**	58,125	100%	55,748	100%
Average Unit Cost ($/MWh)						
Generation (1)	**$ 12.89**		$ 12.53		$ 12.31	
Purchased Power (2)	**$ 41.73**		$ 39.16		$ 78.24	
Overall Average Unit Cost	**$ 16.38**		$ 17.02		$ 21.15	

(1) Represents fuel costs associated with power plants.

(2) Includes amounts associated with hedging activities.

We expect an adequate supply of fuel and purchased power to meet our obligation to serve customers. The effect of lost sales due the electric Customer Choice program has reduced our need for purchased power and increased our ability to sell power in the wholesale market. We have short and long-term supply contracts for expected fuel and purchased power requirements as detailed in the following table:

	2004	
Expected Supply	Contracted	Open
Coal	79%	21%
Natural Gas	29%	71%
Purchased Power	89%	11%

Power Generation’s generating capability is heavily dependent upon coal. The coal is purchased from various sources in different geographic areas under agreements that vary in both pricing and terms. Detroit Edison expects to obtain the majority of its coal requirements through long-term contracts with the balance to be obtained through short-term agreements and spot purchases. Detroit Edison has contracts with three coal suppliers for a total purchase of up to 28 million tons of low-sulfur western coal to be delivered from 2004 through 2008. Detroit Edison also has a contract with a supplier for the purchase of approximately 4 million tons of Appalachian coal to be delivered from 2004 through 2006. These existing long-term coal contracts include provisions for price escalation as well as de-escalation. Given the geographic diversity of supply, Detroit Edison believes it can meet the expected generation requirements. We own and 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.

We purchase power from other electricity generators, suppliers and wholesalers. These purchases supplement our generation capability to meet customer demand during peak cycles. For example, when high temperatures occur during the summer we require additional electricity to meet demand. This access to additional power is an efficient and economical way to meet our obligation to customers without increasing capital expenditures to build additional base-load power facilities.

Regulation

Detroit Edison's Power Generation business is subject to the regulatory jurisdiction of various agencies, including the MPSC, FERC and 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 Fermi 2 nuclear plant.

Since 1996 there have been several important acts, orders, court rulings and legislative actions in the state of Michigan that affect our Power Generation 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 would continue 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 residential customers through 2005 and for small business customers through 2004. 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 electric Customer Choice program. The MPSC has determined that these costs 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.

Due to MPSC orders issued in 1997 and 1998 that altered the regulatory process in Michigan and provided a plan for transition to electric Customer Choice for the generation business of Detroit Edison, effective December 1998, Detroit Edison's generation business no longer met the criteria of SFAS No. 71, "*Accounting for the Effects of Certain Types of Regulation*." Since the June 2000 legislation was enacted into law and with the issuance of subsequent clarifying MPSC orders in 2001 and 2002, rates for retail customers and transition charges for electric Customer Choice customers will be set to recover Detroit Edison's generation costs. Such costs will be billed and recovered from both retail and choice customers and thus satisfy the criteria of SFAS No. 71. In addition, we have the legislative authority to defer regulatory costs in 2002 and 2003 and to begin recovery of such costs starting in 2004 after the mandated rate freeze expires. The recovery of these costs is dependent on authorization from the MPSC. As a result, we resumed application of SFAS No. 71 for our generation business in the fourth quarter of 2002.

In June 2003, Detroit Edison filed an application with the MPSC for a change in retail electric rates, resumption of the Power Supply Cost Recovery (PSCR) mechanism, and recovery of net stranded costs. Detroit Edison is specifically requesting authority to increase rates by $427 million annually with a three-year phase in as customers' rate caps expire. In February 2004, the MPSC authorized an interim base rate increase of $248 million annually.

For additional information regarding our regulatory environment, see Note 4 - Regulatory Matters.

Properties

Detroit Edison owns generating properties and facilities that are all located in the state of Michigan. Substantially all the net utility properties of Detroit Edison are subject to the lien of its mortgage. Power Generation plants owned and in service as of December 31, 2003 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	9.3%	1984 and 1985
Conners Creek	Wayne	215	1.9	1999
Greenwood	St. Clair	785	7.1	1979
Harbor Beach	Huron	103	0.9	1968
Marysville	St. Clair	84	0.8	1930, 1943 and 1947
Monroe (4)	Monroe	3,045	27.6	1971, 1973 and 1974
River Rouge	Wayne	510	4.6	1957 and 1958
St. Clair	St. Clair	1,415	12.8	1953, 1954, 1959, 1961 and 1969
Trenton Channel	Wayne	730	6.6	1949, 1968 and 1999
		7,913	71.6	
Oil or Gas-fueled Peaking Units.	Various	1,102	10.0	1966-1971, 1981 and 1999
Nuclear-fueled Steam-Electric Fermi 2 (5)	Monroe	1,111	10.1	1988
Hydroelectric Pumped Storage Ludington (6)	Mason	917	8.3	1973
		11,043	100.0%	

(1) Summer net rated capabilities of generating units 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 6 – Jointly Owned Utility Plant.

(4) The Monroe Power Plant provided 38% of Detroit Edison's total 2003 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.

Strategy and Competition

We continue to strive to be the preferred electricity supplier in southeast Michigan. We believe that we can accomplish our 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 will continue to make investments in our generating plants that will improve plant availability and improve 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 1, 2002, the electric Customer Choice program expanded in Michigan whereby all of the Company's electric customers can choose to purchase their electricity from alternative suppliers of generation services. Detroit Edison lost 16% of retail sales in 2003 and 6% of such sales in 2002 as a result of customers choosing to purchase power from alternative suppliers under the electric Customer Choice program. If regulatory or legislative changes are not made, we expect to lose between 17% to 20% of retail sales in 2004 as a result of customers choosing to participate in the program. Customers participating in the electric Customer Choice program consist primarily of industrial and large commercial customers. There is a significant price difference in the wholesale and retail markets, which only allows for partial offset of the lost revenue from customer choice migration. We will continue to aggressively utilize the wholesale market to sell the generation made available by the electric Customer Choice program.

Energy Services

Description

Non-regulated Energy Services has three business lines: Coal-Based Fuels, On-Site Energy Projects and Merchant Generation.

Coal-Based Fuels

Coal-Based Fuels operations include producing synthetic fuel from nine synfuel plants and producing coke from three coke battery plants. Both processes generate tax credits under Section 29 of the Internal Revenue Code. Section 29 is designed to stimulate investment in and development of alternate fuel sources. We have private letter rulings from the IRS for all of our synfuel plants. Synfuel-related Section 29 tax credits expire in 2007. Section 29 tax credits for two of our three coke batteries expired at the end of 2002 with the third expiring in 2007.

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. The modification involves a three-step process that produces a solid synthetic fuel product. During 2002, we sold a 95% interest in two of our synfuel plants, and in 2003, we sold a 99% interest in one of our synfuel plants and a 59% interest in two other plants. In January 2004, we sold an additional 40% interest in two of the previously sold plants, reducing our interest to 1%. We continue to consolidate these projects due to our controlling influence.

The coke battery facilities produce coke that is used in blast furnaces within the steel industry. DTE Energy is one of the largest producers in the U.S. of coke for the steel industry. During 2001, we sold a 49% interest in two of our coke battery projects, and in 2002, consistent with the original purchase and sale agreement, our third coke battery project interest was reduced from 95% to 5%.

(Dollars in Millions)	2003	2002	2001
Coal-Based Fuels Statistics			
Synfuel Plants:			
Operational	**9**	9	5
Tax Credits Generated (1)	**$227.7**	$180.2	$64.1
Coke Battery Plants:			
Operational	**3**	3	3
Tax Credits Generated (1)	**$ 2.5**	$ 57.4	$88.6

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

On-Site Energy Projects

Energy Services owns and/or operates on-site facilities, including pulverized coal injection, power generation, steam production, chilled water, wastewater treatment and compressed air. Many of these facilities deliver utility services to industrial, commercial and institutional customers.

Merchant Generation

Energy Services develops and operates peaking and gas-fired electric generating plants. We have four electric generating plants in operation, all located in the Great Lakes region. We have contracts for approximately 33% of the 2004 and 2005 output of these plants and lesser amounts contracted through 2008.

Properties

As of December 31, 2003, Coal-Based Fuels owns interests in and operates nine synfuel plants at eight production sites. Additionally, we have interests in three coke battery facilities in the United States, two of which we operate.

Coal-Based Fuels

Facility	Location	% Owned		Industry Served
Synthetic Fuels				
DTE Red Mountain, LLC	Tarrant, AL	100	%	Foundry Coke/Steel
DTE Belews Creek, LLC	Belews Creek, NC	1	%	Utility
DTE Utah, LLC	Price, UT	100	%	Industrial/Utility
DTE Indy Coke, LLC	Moundsville, WV	100	%	Utility
DTE Clover, LLC	Bledsoe, KY	5	%	Utility
DTE Smith Branch, LLC	Pineville, WV	5	%	Steel/Export
DTE River Hill, LLC	Karthaus, PA	100	%	Utility
DTE Buckeye, LLC (2 plants)	Cheshire, OH	41(1)	%	Utility
Coke Battery				
EES Coke Battery Co.	River Rouge, MI	51	%	Steel
Indiana Harbor Coke Co., LP	East Chicago, IN	5	%	Steel
DTE Burns Harbor LLC	Burns Harbor, IN	51	%	Steel

(1) An additional 40% interest was sold in January 2004.

The following are significant properties owned by On-Site Energy Projects:

On-Site Energy Projects

Facility	Location	Type
PCI Enterprises	River Rouge, MI	Pulverized Coal
DTE Sparrows Point	Sparrows Point, MD	Pulverized Coal
DTE Northwind	Detroit, MI	Steam & Chilled Water
DTE Moraine	Moraine, OH	Compressed Air
DTE Tonawanda	Tonawanda, NY	Chilled & Waste Water
Metro Energy	Romulus, MI	Electricity, Hot and Chilled Water

The Merchant Generation fleet consists of four natural gas-fired electric generating plants that are all located in the Great Lakes region.

Merchant Generation

Facility	Location	% Owned		Capacity (in MW)
DTE Georgetown	Indianapolis, IN	100	%	240
DTE River Rouge	Detroit, MI	100	%	240
Crete Energy Ventures	Crete, IL	50	%	320
DTE East China	East China Twp, MI	100	%	320

Strategy and Competition

Our strategy for Energy Services is to continue leveraging our extensive energy-related operating experience and project management capability to develop and grow the on-site energy business. We continue to evaluate opportunities to sell interests in all of our synfuel plants in 2004. We also 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 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, and then trend towards increased operational scale.

We plan to focus on the following areas for growth:

- Optimization of our synfuel portfolio;
- Providing operating services to owners of power plants;
- Expansion of on-site energy projects; and
- Development of new tax advantaged opportunities.

Energy Marketing & Trading

Description

Energy Marketing & Trading consists of the wholesale electric and gas marketing and trading operations of DTE Energy Trading Company and CoEnergy. We acquired CoEnergy as part of the MCN Energy acquisition in May 2001. Energy Marketing & Trading focuses on physical power marketing and structured transactions for large customers, as well as the enhancement of returns from DTE Energy's power plants, pipeline and storage assets. In pursuing these goals, Energy Marketing & Trading may enter into forwards, futures, swaps and option contracts.

Strategy and Competition

Our strategy for Energy Marketing & Trading is to execute on our vision of the role energy trading plays in delivering value-added services to our customers. Many of the former major market players have either ceased as going concerns or are no longer engaged in the energy trading business. We seek to manage this business in a manner consistent with and complementary to the growth of our other business segments. We plan to focus on physical marketing and the optimization of our portfolio of energy assets. We have risk management and credit policies to monitor and minimize risk.

Coal Services

Description

Coal Services provides fuel, transportation and equipment management services tailored to the individual requirements of each customer. We specialize in minimizing energy production 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. We also operate a number of railcar maintenance and repair facilities serving coal transporters, as well as other industries and rail car types. We participate in the trading of coal and emissions credits as well as coal-to-power tolling transactions. During 2003, we entered into the waste coal recovery business by purchasing a patented technology and constructing our first commercial facility.

Coal Services	2003	2002	2001
Tons of Coal Shipped (in Millions)	**32.0**	28.5	23.5

Properties

We lease approximately 2,600 rail cars. We own fixed and mobile railcar maintenance and repair facilities in Nebraska and Indiana. We completed construction of a waste coal recovery facility on the site of a former operating coal mine in Ohio.

Strategy and Competition

We continue to leverage our position as one of the top North American coal marketers and our reputation as an efficient manager of transportation assets. Trends such as railroad and mining consolidation and the financial uncertainty of 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 the energy requirements of our customers.

We acquired the rights to a proprietary technology that produces high quality coal products from fine coal slurries that are typically discarded from coal mining operations. The technology has the additional benefit of improving the environment by allowing us to restore the land in accordance with reclamation requirements of each state. The technology produces a fine-coal fuel by removing mineral matter, clay-sized impurities and oxides from waste material. The fine-coal fuel can be used in power plants, as a feedstock for synthetic fuel production and for other industrial applications. Our first facility in Ohio became operational in late-2003 and has the capacity to produce more than 500,000 tons of fine coal per year. We are negotiating an agreement for a second facility and plan to site three to five additional facilities in 2004. We believe that the waste coal recovery business will contribute significantly to future earnings and provide significant environmental benefits.

Biomass

Description

Biomass develops, owns and operates landfill gas recovery systems in the U.S. Landfill gas, a by product of solid waste decomposition, is composed of approximately equal portions of methane and carbon dioxide. Converting the methane into a renewable energy resource conserves fossil fuels. Biomass operations generate Section 29 tax credits through 2007.

Biomass helps limit potential greenhouse gas emissions by developing and implementing landfill gas recovery systems that capture the gas and use it productively. Such a recovery system eliminates detrimental air emissions by preventing methane from escaping into the atmosphere or migrating off-site and becoming a safety hazard. Landfill gas recovery systems also provide local utilities, industry and consumers with an opportunity to use a competitive, renewable source of energy. Applications for this form of energy include steam and electricity generation, fueling of asphalt plants and brick kilns and for processing into pipeline quality gas.

(Dollars in Millions)	2003	2002	2001
Biomass			
Landfill Sites	**31**	30	28
Gas Produced (in Bcf)	**26.8**	27.5	24.2
Tax Credits Generated (1)	**$10.5**	$12.9	$ 11.9

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

Properties

Biomass has 31 operating sites located in 14 states and other projects are under development.

Strategy and Competition

Biomass' strategy capitalizes upon our industry experience of over 20 years. We are evaluating business growth through both development and acquisitions. We compete primarily with fossil fuels such as natural gas and coal. However, we believe the environmental benefits of biomass along with reasonable and economic access to landfill sites provide a platform for future growth.

ENERGY DISTRIBUTION

Power Distribution

Description

The electric distribution services of Detroit Edison comprise our regulated Power Distribution business. This business distributes electricity generated by Energy Resources' Power Generation business and alternative electric suppliers to Detroit Edison's 2.1 million customers in southeastern Michigan. This business also shares, with the Gas Distribution segment, the customer service function for our utilities. Accordingly, costs associated with this function, including collections, our call center and uncollectable accounts receivable is shared between Power Distribution and Gas Distribution.

In January 2003, we sold the steam heating business of Detroit Edison to Thermal Ventures II, LP. In February 2003 we sold ITC to an affiliate of Kohlberg, Kravis, Roberts & Co. and Trimaran Capital Partners, LLC. ITC will continue to provide transmission services to the Energy Distribution business at rates that will be recovered from Detroit Edison's utility customers.

Weather and economic factors affect our sales and revenues. Similar to the Power Generation business, our peak load and highest total system sales generally occur during the third quarter of the year driven by air conditioning and cooling-related demands. Power Distribution's sales are not dependent upon a limited number of customers. Additionally, customers participating in the electric Customer Choice program do not impact Power Distribution's operating revenues or the number of customers served. The loss of any one or a few customers is not reasonably likely to have a material adverse effect on Power Distribution.

(in MWh)	2003	2002	2001
Electric Deliveries			
Residential	**15,074**	15,958	14,503
Commercial	**15,942**	18,395	18,777
Industrial	**12,254**	13,590	14,430
Wholesale	**2,241**	2,249	2,159
	45,511	50,192	49,869
Electric Choice	**7,281**	3,510	1,268
Total Electric Deliveries	**52,792**	53,702	51,137

Regulation

Detroit Edison's Power Distribution is subject to the jurisdiction of the MPSC and the FERC, which have regulatory authority over rates, conditions of service and other operating-related matters. As previously discussed, Michigan legislation prevents Detroit Edison from increasing rates to residential customers through 2005 and for small business customers through 2004. By order of the FERC, rates charged by ITC will remain at current levels through December 2004.

In June 2003, Detroit Edison filed an application with the MPSC for a change in retail electric rates, resumption of the PSCR mechanism, and recovery of net stranded costs. In February 2004, the MPSC authorized an interim base rate increase of $248 million annually. See Note 4 for further discussion of the Electric Transitional Rate Plan filing.

In January 2004, the MPSC issued an order adopting rules governing service quality and reliability standards for electric distribution systems. The reliability standards establish performance levels for service restoration, wire-down relief requests, customer call answer time, customer complaint response, meter reading and new service installations. The order also establishes penalties for delays in service restoration during normal conditions, catastrophic storms and repetitive outages. Detroit Edison is required to file an annual report providing information regarding performance against the measures provided and any penalties incurred.

For additional information regarding our regulatory environment, see Note 4 – Regulatory Matters.

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 uncollectable accounts receivable and collections expenses.

Detroit Edison's uncollectable accounts receivable expense is directly affected by the level of government funded assistance its qualifying customers receive. We are working with the State of Michigan and others to increase the share of funding allocated to our customers to be representative of the number of low-income individuals in our service territory.

Properties

Detroit Edison owns and operates 663 distribution substations with a capacity of approximately 31,079,000 kilovolt-amperes (kVA) and approximately 407,000 line transformers with a capacity of approximately 24,542,000 kVA. Substantially all of the net utility properties of Detroit Edison are subject to the lien of its mortgage. Circuit miles of distribution lines owned and in service as of December 31, 2003 are as follows:

Electric Distribution

	Circuit Miles	
Operating Voltage – Kilovolts (kV)	Overhead	Underground
4.8 kV to 13.2 kV	27,916	12,745
24 kV	101	690
40 kV	2,341	325
120 kV	77	13
	30,435	13,773

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

Strategy and Competition

Our strategy focuses on improving the quality of customer service and lowering operating costs by improving operating efficiencies as well as targeting capital investments in areas that have the greatest impact on reliability improvements with the goal of managing distribution rates charged to utility customers.

The decision to sell ITC is consistent with our strategic view that maximization of shareholder value and high levels of customer service are best achieved with assets that we own, operate and over which we exercise significant control. As Detroit Edison's rates are designed to recover transmission costs, billings to Detroit Edison from ITC will be recovered from Detroit Edison's utility customers. Rates charged by ITC to Detroit Edison will, by FERC order, remain at current levels through December 2004. Thereafter, rates would be subject to normal FERC regulation and market forces.

Competition in the regulated electrical distribution business is provided primarily by on-site generation by industrial customers and 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.

Distributed Generation

Description

Distributed Generation, primarily consisting of DTE Energy Technologies (Dtech), has investments in emerging technologies that complement our existing businesses. We currently develop, market and distribute a portfolio of distributed generation products, provide application engineering, and monitor and manage system operations. Distributed generation units seek to generate safe, clean, reliable power at or near the point of use, rather than at large central power stations, which can also provide very high efficiencies due to effective use of waste heat. Distributed generation products can use a range of technologies, including internal combustion engines, external combustion engines, mini-turbines and fuel cells.

The number of megawatts (MW) of distributed generation delivered has increased since 2001, while the average unit size has also increased. Dtech has begun to shift more of its focus on larger industrial and commercial markets and, in particular, on continuous rather than standby generation, and away from the relatively higher volume, smaller margin, residential and small commercial markets. The following table details the distributed generation capacity delivered for the past three years.

	2003	2002	2001
Distributed Generation Capacity Delivered	**94 MW**	89 MW	65 MW

Strategy and Competition

Our goal is to become a profitable participant in the emerging distributed generation market, providing one-stop shopping that meets customers' total energy needs. Key milestones toward this success include full commercialization of our internal combustion engine-driven products as well as our monitoring and system operations management. Our sales structure is in place and we are continuing to expand our project support capabilities, both directly and with partners.

Our strategy is to increase our focus on our proprietary pre-engineered and packaged continuous generation products. Provisions in current as well as proposed federal and state laws are expected to provide us additional opportunities via tax credits, energy efficiency and renewable portfolio standards.

Competition in the distributed generation business comes from distributors and manufacturers of stand-by and continuous duty generators. The success of this business depends on the continued development of new products and the expansion of customer acceptance.

ENERGY GAS

Gas Distribution

Description

Gas Distribution operations primarily consist of MichCon, our regulated gas utility. Gas Distribution provides gas sales and transportation delivery services to 1.2 million residential, commercial and industrial customers located throughout Michigan. As previously discussed, this business also shares with the Power Distribution segment, the customer service function for our utilities.

The following table details sales and deliveries to these customers.

(in Millions)	2003	2002	2001 (1)
Gas Revenues			
Gas Sales	**$1,242**	$ 1,135	$491
End-user Transportation	**136**	122	50
Intermediate Transportation	**51**	48	26
Other	**69**	64	48
	$1,498	$1,369	$615
(in Bcf)			
Gas Deliveries			
Gas Sales	**181**	174	95
End-user Transportation	**152**	171	81
Intermediate Transportation	**576**	492	304
	909	837	480

(1) Includes the operations of MichCon from May 31, 2001 acquisition date.

Gas Distribution makes gas sales primarily to residential and small-volume commercial and industrial customers. It provides end user transportation to large-volume commercial and industrial customers and gas Customer Choice customers who purchase natural gas directly from other suppliers and utilize MichCon's pipeline network to transport the gas to the customers' facilities. Gas Distribution provides intermediate transportation to producers, brokers and other gas companies that own the natural gas transported, but are not the ultimate consumers. MichCon's revenues and net income are impacted by weather and are concentrated in the first and fourth quarters of the year due to heating-related demand. MichCon's operations are not dependent upon a limited number of customers, and the loss of any one or a few customers is not reasonably likely to have a material adverse effect on MichCon.

We obtain our natural gas supply from various sources in different geographic areas under agreements that vary in both pricing and terms.

	2004
Gas Distribution	
Contracted Supply	
Fixed Price Purchases	33%
Market Price Purchases	67%
	100%

Supply under contract represents approximately 75% of the expected 180 Bcf of supply requirements in 2004. We expect to meet the balance of gas supply requirements through open market purchases. As a result of varying demand primarily due to weather, MichCon may use existing gas in inventory to meet unanticipated customer obligations. Given the geographic diversity of supply, coupled with its 124 Bcf of storage capacity, MichCon believes it can meet the supply requirements for customers. MichCon has long-term firm transportation agreements expiring on various dates through 2011 for delivery of purchased natural gas to our distribution system.

Regulation

MichCon is 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 operating-related matters. MichCon is 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. The local utility would continue to transport the natural gas supply to the customers' facilities, thereby retaining distribution margins. In December 2001, the MPSC issued an order that continues the gas Customer Choice program on a permanent and expanding basis beginning with the conclusion of the three-year temporary program on March 31, 2002. Under the expanded program, beginning April 1, 2002, up to approximately 40% of customers could elect to purchase gas from suppliers other than MichCon. Beginning in April 2003, up to approximately 60% of customers could participate, and beginning April 2004, all 1.2 million of MichCon's gas customers could choose to participate. 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.

Under the December 2001 MPSC order, MichCon returned to a gas cost recovery (GCR) mechanism, effective January 2002. Under this mechanism, MichCon's gas sales rates include a gas commodity component designed to recover its actual gas costs and therefore does not have a commodity price risk for prudently incurred gas costs. During 2001, MichCon was under a Gas Sales Program and incurred commodity price risk associated with its ability to secure gas supplies at prices less than $2.95 per Mcf.

In September 2003, MichCon filed an application with the MPSC for an increase in service and distribution charges (base rates) for its gas sales and transportation customers. The filing requests an overall increase in base rates of $194 million per year (approximately 7% increase, inclusive of gas costs), beginning January 1, 2005. MichCon has requested that the MPSC increase base rates by $154 million per year on an interim basis by April 1, 2004. The interim request is based on a projected revenue deficiency for the test year 2004.

For additional information regarding our regulatory environment, see Note 4 - Regulatory Matters.

Energy Assistance Programs

Energy assistance programs funded by the federal government and the State of Michigan, remain critical to MichCon's ability to control its uncollectable accounts receivable expenses.

As previously discussed, we are working with the State of Michigan and others to increase the share of funding allocated to our customers to be representative of the number of low-income individuals in our service territory.

Properties

MichCon owns distribution, transmission and storage properties and facilities that are all located in the state of Michigan. At December 31, 2003, MichCon's distribution system included approximately 18,000 miles of distribution mains, approximately 1,148,000 service lines and approximately 1,279,000 active meters. MichCon owns approximately 2,600 miles of transmission lines that deliver natural gas to the distribution districts and interconnect its storage fields with the sources of supply and the market areas. MichCon owns properties relating to four underground natural gas storage fields with an aggregate working gas storage capacity of approximately 124 Bcf. Substantially all of the net utility properties of MichCon are subject to the lien of its mortgage.

Strategy and competition

The strategy of the Gas Distribution business is to expand our role as the preferred provider of natural gas in Michigan. As a result of more efficient furnaces and appliances, we expect future revenues to remain at current levels or slightly decline. To partially offset these factors, we plan initiatives to expand our gas markets, as well as by continuing to provide energy-related services that capitalize on our expertise, capabilities and efficient systems. We also anticipate increased revenues through increased rates as a result of our rate case, which was filed on September 30, 2003 (see Note 4).

Competition in the gas business primarily involves alternate fuels and energy sources. Natural gas continues to be the preferred space and water-heating fuel. Developers select natural gas in new construction because of the convenience, cleanliness and relative price advantage compared to propane, fuel oil and other alternative fuels.

Gas Production

Description

The Gas Production business owns one of the industry's largest Antrim gas reserve bases predominantly located in the northern portion of the lower peninsula of Michigan. Our emphasis is on developing and producing the 351.9 Bcfe of proved reserves we owned as of December 31, 2003. We drilled 80 wells (68 net of interest of others) in 2003 with a success rate in excess of 90%. Wells drilled in the Antrim shale formation have high success rates and low drilling costs, and are therefore considered low risk.

Gas Production is also involved in the coal bed methane business which is a joint undertaking between Energy Gas and Energy Resources that leverages our gas capabilities with the skills and experience of other non-regulated businesses.

Properties

The Michigan properties had 23.2 Bcfe of production in 2003. Gas Production does not anticipate adding a significant amount of new reserves to its 351.9 Bcfe of proven reserves at December 31, 2003.

Strategy

The Gas Production business is aggressively managing its Michigan gas producing assets to maximize returns on investment. We have operator responsibilities for our Michigan properties with the goal of optimizing the costs of producing reserves. Gas Production has rights to 94,866 acres (81,133 net of interest of others) of undeveloped leases. During 2004, Gas Production plans to continue developing this acreage.

In order to leverage our gas production capabilities and the skills and experience of other non-regulated businesses, we will continue to invest in opportunities in the coal bed methane business. As of December 31, 2003, the coal bed methane business has rights to 4,034 acres (3,156 net of interest of others) of undeveloped leases in Oklahoma. During 2004, the coal bed methane business plans to drill its first operated wells in Oklahoma.

Gas Storage, Pipelines & Processing

Description

The Gas Storage, Pipelines & Processing business has partnership interests in an interstate transmission pipeline, Vector Pipeline (Vector), seven carbon dioxide processing facilities and a 9.7 Bcf natural gas storage field. Additionally, we lease a 42.5 Bcf natural gas storage field located in Michigan.

Properties

Gas Storage, Pipelines & Processing Property Classification	% Owned	Description	Location
Pipelines			
Vector Pipeline	40%	348-mile pipeline with	Midwest
		1,000 MMcf per day capacity	
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	—%	42.5 Bcf of storage capacity	Washington Twp, MI

Strategy and Competition

Gas Storage, Pipelines & Processing focuses on opportunities in the Midwest-to-Northeast region that supply natural gas to meet growing demand. We expect much of the growth in the demand for natural gas in the United States to occur within the Mid-Atlantic and New England regions. These regions currently lack the pipeline capacity and low-cost storage necessary to deliver gas volumes to meet growing demand. Vector is an interstate pipeline that is intended to fill a large portion of that need, and is complemented by Energy Gas' significant storage capacity. Gas Storage, Pipelines & Processing has interests in seven processing plants that extract carbon dioxide from Antrim gas production making it suitable for transportation to nearby markets. Additionally, we have contract rights in natural gas storage fields, capable of storing up to 52.2 Bcf. We plan to continue identifying asset opportunities related to natural gas, storage and transmission and working with other DTE Energy affiliates to secure the market required to support asset investment.

CORPORATE & OTHER

Description

Corporate & Other includes the administrative and general expenses of various corporate support functions such as accounting, legal and information technology. These functions essentially support the entire company and the related costs are allocated to the various segments based on services utilized. Additionally, Corporate & Other holds certain non-regulated debt and investments, including assets held for sale and in emerging energy technologies.

Strategy and Competition

Our energy technology strategy is to invest in a profitable portfolio of energy technology companies that facilitate the creation of new businesses, and expand growth opportunities for existing DTE Energy businesses. We seek to gain early experience in emerging energy sectors where energy trends and technologies may create potentially profitable opportunities. The investment portfolio consists of direct investments in energy technology companies and venture funds.

ENVIRONMENTAL MATTERS

We are subject to extensive environmental regulation. Additional costs may result as the effects of various chemicals 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. Greater details on environmental issues are provided in the following Notes to the Consolidated Financial Statements:

Note	Title
4	Regulatory Matters
5	Nuclear Operations
13	Commitments and Contingencies

Detroit Edison

Detroit Edison is subject to applicable permit requirements, and to potentially increasing stringent federal, state and local standards covering among other things, particulate and gaseous stack emission limitations, the discharge of waste into lakes and streams and the handling and disposal of waste material.

The U.S. Environmental Protection Agency (EPA) issued ozone transport regulations and, in December, 2003, proposed additional emission regulations relating to ozone, fine particulate and mercury air pollution. The new rules have led to additional controls on fossil-fueled power plants to reduce nitrogen oxides, sulfur dioxide, carbon dioxide and particulate emissions. To comply with these new controls, Detroit Edison has spent approximately $560 million through December 2003 and estimates that it will spend approximately $40 million in 2004 and incur up to an additional $1.2 billion of future capital expenditures over the next five to eight years to satisfy both the existing and proposed new control requirements. The EPA initiated enforcement actions against several major electric utilities citing violations of new source provisions of the Clean Air Act. Detroit Edison received and responded to information requests from the EPA on this subject. In October 2003, the EPA promulgated revised regulations to clarify new source review provisions going forward. Several states and environmental organizations have challenged these regulations and in December 2003 the Court stayed the implementation of the regulations until the U.S. Court of Appeals D.C. Circuit renders an opinion in the case. We cannot predict the future impact of this issue upon Detroit Edison.

Detroit Edison is required to demonstrate that the cooling water intake structures at all of its facilities minimize adverse environmental impact. Detroit Edison filed such demonstrations and in the event of a final adverse decision, may be required to install additional control technologies to further minimize the impact.

Various state and federal laws regulate Detroit Edison's handling, storage and disposal of its waste materials. The EPA and the Michigan Department of Environmental Quality (MDEQ) have aggressive programs to manage the clean up of contaminated property. Detroit Edison has extensive land holdings and, from time to time, must investigate claims of improperly disposed contaminants. Detroit Edison anticipates it will be periodically included in these types of environmental proceedings.

MichCon and Citizens

Prior to the construction of major natural gas pipelines, gas for heating and other uses was manufactured from processes involving coal, coke or oil. Enterprises (MichCon and Citizens, a wholly owned gas utility located in Adrian, Michigan) owns, or previously owned, 18 such former manufactured gas plant (MGP) sites. Investigations have revealed contamination related to the by-products of gas manufacturing at each site. Enterprises is remediating seven of the former MGP sites and conducting more extensive investigations at six other former MGP sites. Enterprises received MDEQ closure of one site and a determination that it is not a responsible party for three other sites. Enterprises received closure from the EPA in 2002 for one site. While we cannot make any assurances, we believe that a cost deferral and rate recovery mechanism approved by the MPSC will prevent these costs from having a material adverse impact on our results of operations.

Other

Our non-regulated affiliates are subject to a number of environmental laws and regulations dealing with the protection of the environment from various pollutants. We believe these non-regulated affiliates are in substantial compliance with all environmental requirements.

RISK FACTORS

There are various risks associated with the operations of DTE Energy's regulated and non-regulated 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.

Electric Customer Choice – Without regulatory and legislative changes, the negative impact of the electric Customer Choice program will continue to impact our financial performance.

Weather – Weather significantly affects our 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.

Competition – Deregulation and restructuring in the electric and gas industry, could result in increased competition and unrecovered costs that could affect the financial condition, results of operations or cash flows of our regulated businesses.

Rate regulation – We operate in a regulated industry. Our electric and gas rates are set by the MPSC and the FERC and cannot be increased without their authorization. We may be impacted by new regulations or interpretations by the MPSC, 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. There is no assurance that our currently pending electric and gas rate increases will be granted.

Section 29 tax credits – We have generated Section 29 tax credits from our synfuel, coke battery, biomass and gas production operations. Generating Section 29 tax credits is important to minimizing our income tax expense. Although, we have received favorable private letter rulings on all of our synfuel plants, the generation of tax credits is subject to audit and review by the Internal Revenue Service. If we do not prevail through the administrative and legal processes, there could be additional tax liabilities owed for previously recognized Section 29 tax credits that could impact our earnings and cash flows. Four of our synfuel facilities are under audit by the IRS for 2001. The value of future credits generated may be affected by new tax legislation. The combination of overall industry audits of Section 29 credits, supply and demand for investment in credit producing activities and new tax legislation could hinder our plan to sell interests in tax credit properties that 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 our synfuel facilities.

Credit ratings – 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. Several of the credit agencies have placed a “negative outlook” on our ratings due primarily to the uncertainty regarding our electric and gas rate cases. A downgrade in our rating could restrict or discontinue our ability to access capital markets at attractive rates and increase our borrowing costs.

Regional and national economic conditions – 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.

Environmental laws and liability – 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 because of our emission of gases that may cause changes in the climate. The regulatory environment is subject to significant change and, therefore, we cannot predict future issues.

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 all potentially responsible parties.

Operation of nuclear facilities – Ownership of an operating nuclear generating plant subjects Detroit Edison to significant additional risks. These risks among others, include plant security, environmental regulation and remediation, and operational factors than can significantly impact the performance and cost of operating a nuclear facility.

Supply and price of raw materials – We are dependent on coal for much of our electrical generating capacity. Price fluctuation and 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 regulated gas customers. We have hedging policies in place to mitigate negative fluctuations in commodity supply prices.

Labor relations – Unions represent a majority of our employees. A union choosing to strike as a negotiating tactic would have an impact on our business. We have begun negotiations with unions for contracts expiring in 2004 and cannot predict the outcome. An unfavorable outcome, such as a strike, could adversely impact the business.

Unplanned outages – Unforeseen maintenance may be required to safely produce electricity or comply with environmental regulations. This occurrence could result in spot market purchases of electricity in excess of our costs of generation.

Access to capital markets and interest rates – 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.

Cash flows from subsidiaries - Cash flows from 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 dividends and interest would be restricted.

Property tax reform – We are one of the largest payers of property taxes in the state of Michigan. Should the legislature change how schools are financed, we could face increased property taxes on our Michigan facilities.

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 – Damage to downstream infrastructure or our own assets by terrorist groups would impact our operations.

Energy trading markets – Events in the energy trading industry have increased the level of scrutiny on the energy trading business and the energy industry as a whole. A decline in the confidence in the energy trading market along with stricter credit requirements has led to a decrease in the number of trading entities resulting in decreased liquidity in the energy trading market.

EMPLOYEES

The table below shows our employees as of December 31, 2003:

	Represented	Non-represented	Total
Detroit Edison	4,062	3,946	8,008
MichCon	1,514	787	2,301
Other	98	692	790
Total	5,674	5,425	11,099

There are several bargaining units for our represented employees. Of the 5,674 represented employees, 4,695 are under contracts that expire in June through October 2004. The contracts of the remaining represented employees expire in 2005 through 2007. We have begun negotiations on the labor contract that expires in June of 2004 and cannot predict the outcome.

EXECUTIVE OFFICERS OF DTE ENERGY

Name	Age (1)	Present Position	Present Position Held Since
Anthony F. Earley, Jr.	54	Chairman of the Board, Chief Executive Officer, President, Chief Operating Officer	8-1-98
Gerard M. Anderson	45	Group President, Energy Resources	5-31-01
Robert J. Buckler	54	Group President, Energy Distribution	5-31-01
Stephen E. Ewing	59	Group President, Energy Gas	5-31-01
David E. Meador	46	Senior Vice President and Chief Financial Officer	5-31-01
Bruce D. Peterson	47	Senior Vice President and General Counsel	6-25-02
S. Martin Taylor	63	Senior Vice President	4-28-99
Susan M. Beale	55	Vice President and Corporate Secretary	12-11-95
Daniel G. Brudzynski	43	Vice President and Controller	2-8-01

(1) As of December 31, 2003

Under our By-Laws, 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. Ewing and Peterson, all of the above officers have been employed by DTE Energy in one or more management capacities during the past five years.

Stephen E. Ewing was elected group president for DTE Energy Gas on May 31, 2001. He joined DTE Energy having previously served as president and chief operating officer of MCN Energy and president and chief executive officer of MichCon during the previous five years.

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.

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 permissible 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 six insurance policies providing aggregate coverage in the amount of $150 million.

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 the Consolidated Financial Statements:

Note	Title
4	Regulatory Matters
5	Nuclear Operations
13	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 2003.

Part II

Item 5. Market for Registrant's Common Equity and Related Stockholder Matters

Our common stock is listed on the New York Stock Exchange, which is the principal market for such stock, and the Chicago Stock Exchange. 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:

Calendar	Quarter	High	Low	Dividends Paid Per Share
2003				
	First	**$ 49.50**	**$ 38.51**	**$ 0.515**
	Second	**$ 44.95**	**$ 38.52**	**$ 0.515**
	Third	**$ 38.98**	**$ 34.00**	**$ 0.515**
	Fourth	**$ 39.76**	**$ 35.12**	**$ 0.515**
2002				
	First	$ 45.75	$ 39.65	$ 0.515
	Second	$ 47.70	$ 42.65	$ 0.515
	Third	$ 44.56	$ 33.05	$ 0.515
	Fourth	$ 46.90	$ 38.20	$ 0.515

At December 31, 2003, there were 168,606,522 shares of our common stock outstanding. These shares were held by a total of 105,173 shareholders of record.

Our By-Laws 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 8 – Common Stock and Earnings Per Share for additional information, including information concerning the Shareholders' Rights Plan.

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 at the current rate of $0.515 per quarter for the foreseeable future. See Note 9 - Long-Term Debt and Preferred Securities for possible restrictions on the payment of dividends.

Pursuant to Article I, Section 8.(c) and Article II, Section 3.(c) of our By-laws, as amended through September 1, 1999, notice is given that the 2004 Annual Meeting of the company's Common Shareholders will be held on Thursday April 29, 2004.

All of our equity compensation plans that provide for the annual awarding of stock-based compensation have been approved by shareholders. See Note 15 — Stock Based Compensation for additional detail. See below for information as of December 31, 2003.

	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	6,653,122	$ 40.18	8,728,461

Table of Contents

Item 6. Selected Financial Data

The following selected financial data should be read with the accompanying Management's Discussion and Analysis and Notes.

(in Millions, except per share amounts)	2003	2002	2001(1)	2000	1999
Operating Revenues	**$ 7,041**	$ 6,729	$ 5,787	$ 4,638	$ 4,499
Net Income					
Regulated operations	**$ 281**	$ 418	$ 198	$ 427	$ 434
Non-regulated operations (2)	**199**	168	111	41	49
Total from continuing operations	**480**	586	309	468	483
Discontinued operations (3)	**68**	46	20	—	—
Cumulative effect of accounting changes	**(27)**	—	3	—	—
Net Income	**$ 521**	$ 632	$ 332	$ 468	$ 483
Diluted Earnings Per Share					
Regulated operations	**$ 1.67**	$ 2.53	$ 1.29	$ 2.99	$ 3.00
Non-regulated operations (2)	**1.18**	1.02	.72	.28	.33
Total from continuing operations	**2.85**	3.55	2.01	3.27	3.33
Discontinued operations (3)	**.40**	.28	.13	—	—
Cumulative effect of accounting changes	**(.16)**	—	.02	—	—
Diluted Earnings Per Share	**$ 3.09**	$ 3.83	$ 2.16	$ 3.27	$ 3.33
Financial Information					
Dividends Declared Per Share of Common Stock	**$ 2.06**	$ 2.06	$ 2.06	$ 2.06	$ 2.06
Total Assets	**$20,753**	$19,985	$19,587	$13,350	$13,021
Long-Term Debt, including capital leases	**$ 7,669**	$ 7,803	$ 7,928	$ 4,039	$ 4,091
Shareholders' Equity	**$ 5,287**	$ 4,565	$ 4,589	$ 4,009	$ 3,909

(1) Includes the operations of MCN Energy from the May 31, 2001 acquisition date.

(2) Includes Corporate & Other.

(3) Represents the operations of ITC that were sold in February 2003 (Note 3).

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

OVERVIEW

DTE Energy is a diversified energy company with approximately $7 billion in revenues in 2003 and approximately $21 billion in assets at December 31, 2003. We are the parent company of Detroit Edison and MichCon, regulated electric and gas utilities engaged primarily in the business of providing electricity and natural gas sales and distribution services throughout southeastern Michigan. Additionally, we have numerous non-regulated subsidiaries involved in energy-related businesses predominantly in the Midwest and eastern U.S.

The majority of our earnings are derived from utility operations and the production of synthetic fuel, which qualifies for Section 29 tax credits. Earnings in 2003 were $521 million, or $3.09 per diluted share, down from 2002 earnings of $632 million, or $3.83 per diluted share. Earnings from continuing operations in 2003 were $480 million, or $2.85 per diluted share, compared to 2002 earnings from continuing operations of $586 million, or $3.55 per diluted share. The 18% decrease in income reflects significantly lower utility earnings, partially offset by increased contributions from our non-regulated businesses. Our 2003 financial performance was primarily influenced by:

- Weather, including storms and power outages;
- Lost revenues from electric Customer Choice penetration;
- The regulatory environment in Michigan and the need to increase utility rates;
- Higher operating costs;
- The optimization of Section 29 tax credits; and
- Growth of non-regulated businesses

Weather – Earnings in our electric and gas utilities are seasonal and extremely sensitive to weather. Electric utility earnings are dependent on hot summer weather while the gas utility's results are driven by cold winter weather. We experienced both milder summer and winter weather during 2003, which negatively impacted sales demand. The lower demand reduced current year earnings by $64 million compared to 2002, which was an above-normal weather demand year.

Additionally, we occasionally experience various types of storms that damage our electric distribution infrastructure resulting in power outages. Our current year earnings were affected by several catastrophic wind and ice storms, as well as by the August blackout. Restoration and other costs associated with these power outages lowered 2003 earnings by an additional $31 million compared to 2002.

Electric Customer Choice Program - The electric Customer Choice program as originally structured in Michigan anticipated an eventual transition to a totally deregulated and competitive environment where customers would be charged market-based rates for their electricity. However, Detroit Edison's rates continue to be regulated by the MPSC, while alternative suppliers can charge market-based rates. This continued regulation has hindered Detroit Edison's ability to retain customers. Detroit Edison's results have been unfavorably impacted by the lack of recovery of lost margins and other costs associated with the electric Customer Choice program. Under Michigan legislation, we are allowed to recover net stranded costs associated with the electric Customer Choice program. To date, the MPSC has not fully implemented various provisions of Michigan's restructuring legislation. Specifically, the MPSC:

- has not finalized all the components for calculating net stranded costs;
- has created a process whereby net stranded costs would be recovered two years after the costs were actually incurred;
- has not authorized timely recovery of any implementation costs associated with the electric Customer Choice program; and
- has created artificial incentives to encourage participation in the electric Customer Choice program

In addition, the MPSC has maintained regulated rates for certain groups of customers that exceed the cost of service to those customers. This has resulted in high levels of participation in the electric Customer Choice program by those customers that have the highest price relative to their cost of service. As a result, we continue to lose sales each year and are seeing an accelerating pace of migration towards the end of 2003. Lost margins and electricity volumes associated with electric Customer Choice were approximately $120 million and 7,281 gigawatthour (gWh) in 2003, compared with $50 million and 3,510 gWh in 2002. In February 2004, the MPSC authorized an interim base rate increase that recognized a revenue deficiency for lost Choice revenues, and eliminated transition credits and implemented a transition charge for Choice customers. The interim order is expected to reduce the level of Choice sales volumes. Assuming no further changes to the current electric Customer Choice program, we expect to continue losing margins and volumes in 2004. Partially offsetting the impact of lost margins in 2003, we recorded regulatory assets of $68 million representing an estimate of stranded costs that we believe are recoverable under Michigan legislation. Based on the MPSC's July 2003 order, we do not believe that any of the stranded costs in years prior to 2003 are recoverable. There are a number of variables and estimates that impact the level of recoverable stranded costs, including weather, sales mix and wholesale prices. As a result, our estimate of stranded costs could increase or decrease. The actual amount of stranded costs to be recovered will ultimately be determined by the MPSC.

Detroit Edison addressed numerous issues with the electric Customer Choice program, including stranded costs, in its June 2003 rate filing and is also pursuing a legislative solution. Under the legislative solution, we are proposing to limit Customer Choice program participation to customers whose electric demand is 1 MW or greater. The continued delay in addressing the structural problems of the electric Customer Choice program and the timely and full recovery of stranded costs, unfavorably impacts earnings and cash flow. See Note 4 for a further discussion of the electric Customer Choice program and the MPSC interim rate order.

Electric and Gas Rate Plans – In 2000, Michigan legislation froze electric rates for all residential, commercial and industrial customers through 2003. The legislation also prevented rate increases or capped rates for residential customers through 2005, and for small commercial and industrial customers through 2004. The rate freeze and caps apply to base rates as well as rates designed to recover fuel and purchased power costs. Historically, these costs have been a pass-through under the power supply cost recovery (PSCR) mechanism.

In June 2003, Detroit Edison filed an application with the MPSC for: 1) an increase in retail electric rates of $427 million annually, 2) the resumption of the PSCR mechanism, and 3) the recovery of net stranded and other costs as permitted under Michigan legislation. Detroit Edison received an interim order in this rate case authorizing an increase in rates of $248 million annually. As a result of rate caps and other factors, the interim rate increase is only designed to increase revenues by $71 million in 2004 (Note 4). A final order is expected in the third quarter of 2004. The rate increase is effective for each customer class upon the expiration of the applicable rate cap period. The rate request is designed to more accurately reflect, among other things, significantly higher cost of service levels that Detroit Edison has experienced over the past few years.

The recovery of net stranded costs, electric Customer Choice implementation costs and other costs incurred as a result of changes in taxes, laws and governmental actions are covered under Michigan legislation. However, the MPSC has not approved a final mechanism to recover such costs, and this has negatively affected our cash flow. As part of its rate filing, Detroit Edison has requested authorization to implement a 5-year surcharge to recover these costs. The MPSC deferred addressing this item until a final rate order is issued.

In September 2003, MichCon filed an application with the MPSC for an increase in service and distribution charges for its gas sales and transportation customers totaling $194 million annually. The rate increase would be MichCon's first since 1992, and is designed to recover significantly higher operating costs. MichCon expects an interim order in this case in mid-2004, with a final order by January 2005.

Operating Costs – During 2003, we experienced double-digit increases in regulated operation and maintenance costs. The increases were driven by higher costs associated with pension and health care benefits, uncollectable accounts receivable and customer service initiatives. To address this issue of rising costs, we implemented several cost savings initiatives that partially offset these increases. Some of the initiatives were structural in nature, whereas others were temporary. Examples of these initiatives included a hiring freeze, a pause on discretionary spending and overtime restrictions. Additionally, we reduced employee compensation costs, property and other taxes as well as interest costs through debt refinancings.

Synthetic Fuel Operations - We operate nine synthetic fuel production plants at eight locations. Interests in two of the nine plants were sold in 2002, interests in three other plants were sold in November 2003, and additional interests were sold in January 2004 in two of the plants sold in 2003. We continue to wholly own the remaining four plants, but intend to sell interests in all such plants in 2004. Synfuel facilities chemically change coal, including waste and marginal coal, into a synthetic fuel as determined under applicable IRS rules. Section 29 of the Internal Revenue Code provides tax credits for the production and sale of solid synthetic fuel produced from coal. In addition to meeting various qualifying conditions, a taxpayer must have sufficient taxable income to earn the Section 29 credits.

Our 2003 earnings were unfavorably affected by our inability to sell interests in synfuel plants until late 2003. The IRS suspended the issuance of private letter rulings (PLRs) relating to synthetic fuel projects in May 2003, pending its review of issues concerning chemical change, which is the basis for earning Section 29 tax credits. As a result of the IRS suspension, we were unable to complete the pending sale of interests in our synfuel projects. In addition, we experienced lower taxable earnings due to milder weather and continued cost and margin pressures. The temporary delay in selling interests in the synfuel projects, coupled with the lower taxable earnings, resulted in our capacity to generate more credits than we could utilize. These factors caused us to reduce our synthetic fuel production by approximately one-half in June 2003 to optimize the tax credits generated from these facilities. We began implementing a series of initiatives, including the monetization of in-the-money gas swap derivative contracts, to improve cash flow and increase taxable income thereby allowing us to more fully utilize our Section 29 tax credits.

In October 2003, the IRS concluded its assessment of the chemical change process involved in synfuel production and resumed issuing PLRs. The IRS determined that the test procedures and results used by taxpayers were scientifically valid if the procedures were applied in a consistent and unbiased manner. The conclusion of the IRS assessment allowed us to complete the sale of interests in additional facilities and increase synfuel production levels for the balance of 2003.

Non-regulated Growth – During 2003, we continued to experience growth in our non-regulated businesses with income reaching $199 million compared to $168 million in 2002. The significant improvement reflects increased contributions from our Energy Services segment due to higher synfuel production, partially offset by the impact of certain coke battery-related Section 29 tax credits expiring in 2002. Additionally, non-regulated growth in 2003 is attributable to increased margins in our Energy Marketing & Trading segment. We also realized gains in 2003 from the sale of our 16% interest in the Portland Natural Gas Transmission System, an interstate pipeline company, and the settlement of a tolling contract at one of our merchant generating facilities.

Although DTE Energy’s overall earnings were down 18% in 2003, our cash from operations totaling $950 million was comparable to the prior year despite a $222 million cash contribution to our pension plan. Operating cash flow reflects our successful initiative in 2003 to conserve cash, including better working capital management. This initiative coupled with $233 million in lower capital expenditures and over $750 million from selling non-strategic and other assets, resulted in a lower debt to total capital ratio and a healthier balance sheet.

Outlook - We are facing many challenges in 2004 to maintain earnings and cash flow levels, while protecting a strong balance sheet. Our financial performance over the short term will be dependent on preserving healthy electric and gas utilities, monetizing our synthetic fuel projects and continuing to grow our non-regulated businesses in a prudent manner.

Remedying the structural issues of the electric Customer Choice program in Michigan is a key priority for the organization. These issues must be corrected to prevent the continued migration of customers to the Choice program based on false market signals. The potential implications to remaining customers over the longer term could be significantly higher electricity rates.

The timing and ultimate amount of final rate relief granted in the current electric and gas rate cases will affect customer service levels and our financial performance. Cash flow and earnings from our utilities will remain under pressure until the regulatory uncertainties are resolved. However, we remain focused on good cash management and a healthy balance sheet.

We are aggressively pursuing the sales of interests in all of our remaining synthetic fuel projects in 2004. These sales, in addition to previously completed sales, are expected to provide a $200 million to $300 million boost to our cash flow in 2004. The availability of qualified buyers and the timing of these sales will impact this financial outcome. In addition, we are continuing to grow our non-regulated businesses in areas such as waste coal technologies, coal bed methane production and on-site energy project development. Due to the regulatory uncertainties over the short term, we remain disciplined and conservative in our pursuit of incremental growth investments.

RESULTS OF OPERATIONS

We had income of $521 million in 2003, or $3.09 per diluted share, compared to income of $632 million, or $3.83 per diluted share in 2002 and income of $332 million, or $2.16 per diluted share in 2001. The comparability of earnings was impacted by the sale of our transmission business, International Transmission Company (ITC), and the adoption of new accounting rules as subsequently discussed. Upon selling ITC in February 2003, we classified this business as a discontinued operation. Excluding discontinued operations and the cumulative effect of accounting changes, our earnings from continuing operations in 2003 were $480 million, or $2.85 per diluted share, compared to earnings of $586 million, or $3.55 per diluted share in 2002 and earnings of $309 million, or $2.01 per diluted share in 2001. The following sections provide a detailed discussion of our segments, operating performance and future outlook.

Segment Performance & Outlook - We operate our businesses through three strategic business units (Energy Resources, Energy Distribution and Energy Gas). Each business unit has regulated and non-regulated operations. The balance of our business consists of Corporate & Other. Based on this structure, we set strategic goals, allocate resources and evaluate performance. This results in the following reportable segments.

(in Millions, except per share data)	2003	2002	2001
Net Income (Loss)			
Energy Resources			
Regulated - Power Generation	**$ 235**	$ 241	$ 139
Non-regulated			
Energy Services	**199**	182	115
Energy Marketing & Trading	**45**	25	44
Other	**(2)**	7	6
Total Non-regulated	**242**	214	165
	477	455	304
Energy Distribution			
Regulated - Power Distribution	**17**	111	97
Non-regulated	**(15)**	(16)	(10)
	2	95	87
Energy Gas			
Regulated - Gas Distribution	**29**	66	(38)
Non-regulated	**29**	26	11
	58	92	(27)
Corporate & Other	**(57)**	(56)	(55)
Income from Continuing Operations			
Regulated	**281**	418	198
Non-regulated (1)	**199**	168	111
	480	586	309
Discontinued Operations	**68**	46	20
Cumulative Effect of Accounting Changes	**(27)**	—	3
Net Income	**$ 521**	$ 632	$ 332
Diluted Earnings Per Share			
Regulated	**$ 1.67**	$ 2.53	$ 1.29
Non-regulated (1)	**1.18**	1.02	.72
Income from Continuing Operations	**2.85**	3.55	2.01
Discontinued Operations	**.40**	.28	.13
Cumulative Effect of Accounting Changes	**(.16)**	—	.02
Net Income	**$ 3.09**	$ 3.83	$ 2.16

(1) Includes Corporate & Other.

Table of Contents

ENERGY RESOURCES

Power Generation

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

(in Millions)	2003	2002	2001
Operating Revenues	**$ 2,448**	$ 2,711	$ 2,788
Fuel and Purchased Power	**(920)**	(1,048)	(1,231)
Gross Margin	**1,528**	1,663	1,557
Operation and Maintenance	**(628)**	(626)	(571)
Depreciation and Amortization	**(224)**	(331)	(385)
Taxes Other Than Income	**(157)**	(156)	(148)
Merger and Restructuring Charges (Note 3)	**—**	—	(72)
Operating Income	**519**	550	381
Other Income and (Deductions)	**(149)**	(189)	(184)
Income Tax Provision	**(135)**	(120)	(58)
Net Income	**$ 235**	$ 241	$ 139
Operating Income as a Percent of Operating Revenues	**21%**	20%	14%

Factors impacting income: Power Generation earnings decreased $6 million in 2003 and increased $102 million in 2002, compared to the prior year. As subsequently discussed, these results primarily reflect changes in gross margins, increased operation and maintenance expenses and the recording of higher regulatory deferrals, which lowered depreciation and amortization expenses.

Merger and restructuring charges associated with the 2001 MCN Energy acquisition also impacted the comparability of results. These charges represent costs associated with systems integration, relocation, legal, accounting and consulting services, as well as costs associated with a work force reduction plan. The plan included early retirement incentives and voluntary separation agreements for employees in overlapping corporate support areas.

Gross margins in 2003 declined $135 million due primarily to decreased cooling demand resulting from mild summer weather, lost margins from customers choosing to purchase power from alternative suppliers under the electric Customer Choice program and lost margins from the August 2003 blackout. Weather in 2003 was 38% milder than 2002 resulting in lost margins of $114 million. Detroit Edison lost 16% of retail sales in 2003 and 6% of such sales in 2002 as a result of customers choosing to purchase power from alternative suppliers under the electric Customer Choice program. We estimate that we lost $120 million of margins in 2003 under the electric Customer Choice program, an increase of $70 million over 2002. Lost Choice margins that we believe are recoverable under Michigan legislation are recorded as regulatory assets and therefore reduced depreciation and amortization expense as subsequently discussed. Gross margins benefited from a $.64 per MWh (4%) decline in fuel and purchased power costs reflecting the use of a more favorable power supply mix. The favorable mix is due to lower purchases, which is driven by lost sales under the electric Customer Choice program.

Gross margins in 2002 improved $106 million due primarily to significantly lower fuel and purchased power costs, partially offset by reduced operating revenues. The reduction in fuel and purchased power costs was driven by a $39.08 per MWh (50%) reduction in average purchased power prices from 2001 levels. The decline in operating revenues is attributable to commercial, industrial and wholesale customers. Commercial and industrial revenues were lower due to a full year's impact of a 5% legislatively mandated rate reduction for customers that began in April 2001. Additionally, revenues from these retail customers were affected by customers switching to alternative suppliers under the electric Customer Choice program. Revenues from wholesale customers were reduced, reflecting lower power prices. Partially offsetting these revenue reductions was the impact of weather, resulting in a 10% increase in cooling demand during 2002.

(in Thousands of MWh)	2003		2002		2001	
Power Generated and Purchased						
Power Plant Generation						
Fossil						
Coal	**37,408**	**71%**	37,381	64%	38,424	69%
Natural Gas & Other	**644**	**1**	1,636	3	1,287	2
Nuclear (Fermi 2)	**8,114**	**16**	9,301	16	8,555	16
	46,166	**88**	48,318	83	48,266	87
Purchased Power	**6,354**	**12**	9,807	17	7,482	13
System Output	**52,520**	**100%**	58,125	100%	55,748	100%
Average Unit Cost ($/MWh)						
Generation (1)	**$ 12.89**		$ 12.53		$ 12.31	
Purchased Power (2)	**$ 41.73**		$ 39.16		$ 78.24	
Overall Average Unit Cost	**$ 16.38**		$ 17.02		$ 21.15	

(1) Represents fuel costs associated with power plants.

(2) Includes amounts associated with hedging activities.

Operation and maintenance expense increased $2 million in 2003 and $55 million in 2002. Operation and maintenance expenses in 2003 were affected by $5 million in costs associated with the August 2003 blackout (Note 4) and a $69 million increase in employee pension and health care benefit costs, due to recent financial market performance, lower discount rates and increased health care trend rates. Partially offsetting these increases were benefits from the DTE Operating System, our company-wide initiative to pursue cost efficiencies as well as enhance operating performance. The DTE Operating System involves the application of tools and operating practices, which have resulted in inventory reductions and improvements in technology systems, among other enhancements. Operation and maintenance expenses in 2003 also benefited from $23 million in sales of emissions credits and lower employee incentive costs.

Operation and maintenance expenses in 2002 reflect $18 million in higher employee pension and health care benefit costs and $43 million in expenses associated with maintaining our generation fleet. The 2002 increase also includes a $5 million increase in allocations for corporate support services, as well as $11 million to fund the low income and energy efficiency fund. The funding of the low income and energy efficiency program was required under Michigan legislation and is recovered in current sales rates.

Depreciation and amortization expense decreased $107 million in 2003 and $54 million in 2002. The decrease in depreciation and amortization expense is attributable to the income effect of recording regulatory assets totaling $126 million in 2003 and $41 million in 2002 representing the deferral of net stranded and other costs we believe are recoverable under Public Act 141. The decline in 2002 also reflects the extension of the amortization period from seven years to 14 years for certain regulatory assets that were securitized in 2001. See Note 4 – Regulatory Matters. Partially offsetting these declines was increased depreciation associated with generation-related capital expenditures.

Other income and deductions declined $40 million in 2003 and increased $5 million in 2002. The reduction in 2003 is attributable to lower interest expense and increased interest income. Interest expense reflects lower borrowing levels and rates, and interest income includes the accrual of carrying charges on environmental-related regulatory assets.

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

As previously discussed, we expect to continue losing retail sales and margins in future years under the electric Customer Choice program until the inequities associated with this program are addressed. We will accrue as regulatory assets our unrecovered generation-related fixed costs due to electric Customer Choice that we believe are recoverable under Michigan legislation. We have addressed the issue of stranded costs in our June 2003 electric rate filing and are also pursuing a legislative solution. Additionally, we requested an increase in retail electric rates of $427 million annually to recover higher operating costs and the resumption of the PSCR mechanism. In February 2004, the MPSC authorized an interim base rate increase of $248 million annually. The actual timing and level of recovering stranded and operating costs will ultimately be determined by the MPSC or legislation. We cannot predict the outcome of these matters. See Note 4 – Regulatory Matters.

Table of Contents

Energy Services

Energy Services is comprised of Coal-Based Fuels, On-Site Energy Projects and Merchant Generation. Coal-Based Fuels operations include producing synthetic fuel from nine synfuel plants and producing coke from three coke battery plants. Both processes generate tax credits under Section 29 of the Internal Revenue Code. On-Site Energy Projects include pulverized coal injection, power generation, steam production, chilled water production, wastewater treatment and compressed air supply. Merchant Generation owns and operates four gas-fired peaking electric generating plants and develops and acquires gas and coal-fired generation.

(in Millions)	2003	2002	2001
Operating Revenues			
Coal-Based Fuels	**$ 850**	$ 559	$ 365
On-Site Energy Projects	**70**	63	53
Merchant Generation	**9**	23	29
	929	645	447
Operation and Maintenance	**(966)**	(708)	(400)
Depreciation, Depletion and Amortization	**(84)**	(81)	(85)
Taxes other than Income	**(18)**	(15)	(6)
Operating Loss	**(139)**	(159)	(44)
Other Income and (Deductions)	**89**	73	(14)
Income Taxes			
Benefit	**19**	30	20
Section 29 Tax Credits	**230**	238	153
	249	268	173
Net Income	**$ 199**	$ 182	$ 115

Factors impacting income: Energy Services earnings increased $17 million in 2003 and $67 million in 2002, compared to the prior year. As subsequently discussed, these results primarily reflect increases in synfuel production, varying levels of Section 29 tax credits, a one-time contract gain and a write-off of an uncollectable account.

Operating revenues increased $284 million in 2003 and $198 million in 2002 reflecting higher synfuel production due to a greater number of operating synfuel plants. All nine of our synfuel plants were operational throughout 2003, whereas only five were operational throughout 2002 and only two in 2001. As discussed in Note 13, the growth in synfuel revenues was tempered by our decision to reduce synfuel production by approximately one-half in June 2003. Also impacting the 2003 comparison was reduced generation revenue due to the settlement of a tolling contract at one of our generating facilities.

(Dollars in Millions)	2003	2002	2001
Coal-Based Fuels Statistics			
Synfuel Plants:			
Operational at End of Year	**9**	9	5
Tax Credits Generated (1)	**$ 227.7**	$ 180.2	$64.1
Coke Battery Plants:			
Operational at End of Year	**3**	3	3
Tax Credits Generated (1)	**$ 2.5**	$ 57.4	$88.6

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

Operation and maintenance expense increased $258 million in 2003 and $308 million in 2002, reflecting costs associated with the higher levels of synfuel production. Operating expenses associated with synfuel projects exceed operating revenues and therefore generate operating losses, which are more than offset by the resulting Section 29 tax credits. Operation and maintenance expense in 2003 also includes a $10 million net of tax write-off for an uncollectable receivable associated with a large customer bankruptcy. Partially offsetting these increases was a one-time $19 million net of tax gain from the settlement of the tolling contract.

Other income and deductions increased $16 million in 2003 and $87 million in 2002. The increases reflect our minority partners' share of operating losses associated with synfuel operations. The sale of interests in our synfuel facilities during 2002 and 2003 resulted in our minority partners being allocated a larger percentage of such losses.

Income tax benefits decreased $19 million in 2003 and increased $95 million in 2002. Income tax variations reflect changes in taxable earnings and the level of Section 29 tax credits from our synfuel and coke battery facilities. Tax credits from our synfuel operations increased in each of the last two years due to higher synfuel production. Tax credits from our coke battery production reflect the expiration of such credits at two of our three plants in 2002. Additionally, tax credits were impacted by our interest in one of the coke battery projects being reduced from 95% to 5% in 2002, consistent with the original purchase and sale agreement.

Outlook - A significant portion of Energy Services' earnings consist of Section 29 tax credits. Synfuel-related tax credits expire in 2007. Tax credits for two of our three coke batteries expired at the end of 2002, and the third expires in 2007. We are aggressively pursuing opportunities to sell interests in all of our synfuel plants in 2004. The level of tax credits generated in future periods will be affected by the timing and number of synfuel projects sold. When we sell an interest in a synfuel facility, we recognize the gain from such sale under the installment method of accounting. Gain recognition is dependent on the synfuel production qualifying for Section 29 tax credits. In substance, we are receiving installment gains and reduced operating losses in exchange for tax credits. Sales of interests in synfuel projects allow us to accelerate cash flow while maintaining a stable income base.

There is a bill currently before the United States Congress that includes provisions extending or reinstating tax credits for various types of energy facilities and processes, including coke batteries, Antrim shale gas, coal bed methane, refined coal and landfill gas. We are unable to predict the outcome of the legislative process.

Energy Services will continue leveraging its extensive energy-related operating experience and project management capability to develop and grow the on-site energy business. We continue to explore growth opportunities that will not require significant initial capital investment. We are currently negotiating an on-site energy business arrangement with a major manufacturer in the Midwest.

Power prices over the past few years have been low due, in part, to the current excess capacity in the generation industry. Additionally, the generation tolling agreement that was settled in 2003 was at above market rates. As a result of these factors, we expect lower revenues and earnings from our merchant generation business in 2004.

Energy Marketing & Trading

Energy Marketing & Trading consists of the electric and gas marketing and trading operations of DTE Energy Trading and CoEnergy. DTE Energy Trading focuses on physical power marketing and structured transactions, as well as the enhancement of returns from DTE Energy's power plants. CoEnergy focuses on physical gas marketing and the optimization of DTE Energy's owned and contracted natural gas pipelines and gas storage capacity. To this end, both companies enter into derivative financial instruments as part of their strategies, including forwards, futures, swaps and option contracts. The derivative financial instruments are accounted for under the mark to market method, which results in earnings recognition of unrealized gains and losses from changes in the fair value of the derivatives.

Factors impacting income: Energy Marketing & Trading's earnings increased $20 million in 2003, of which $18 million was attributable to DTE Energy Trading and $2 million to CoEnergy. Earnings for 2002 decreased $19 million, consisting of a $6 million improvement at DTE Energy Trading, which was more than offset by a $25 million reduction at CoEnergy.

DTE Energy Trading's earnings improvement in 2003 and 2002 was due mainly to margins associated with short-term physical trading and origination activities. The improvement was partially offset by reduced proprietary trading profits. Proprietary trading represents derivative activity transacted with the intent of capturing profits on forward price movements.

(Dollars in Millions)	2003	2002	2001
DTE Energy Trading			
Margins – gains (losses)			
Realized (1)	**$ 82**	$ 38	$ 33
Unrealized (2)	**(9)**	13	(6)
	73	51	27
Operating and other costs	**(28)**	(29)	(14)
Income taxes	**(13)**	(8)	(5)
Net income	**$ 32**	$ 14	$ 8
CoEnergy			
Margins – gains (losses)			
Realized (1)	**$ 168**	$ 32	$ (6)
Unrealized (2)	**(135)**	(62)	108
Unrealized-gas in inventory (3)	**—**	74	(28)
	33	44	74
Operating and other costs	**(13)**	(27)	(19)
Income taxes	**(7)**	(6)	(19)
Net income	**$ 13**	$ 11	$ 36
Total Energy Marketing & Trading Net Income	**$ 45**	$ 25	$ 44

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

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

3) Unrealized – gas in inventory margins represent gains and losses associated with fair value accounting in 2002 and 2001. CoEnergy changed its method of accounting for inventory in January 2003 (Note 2).

CoEnergy's earnings in 2003 and 2002 were driven by varying levels of operating costs and margins. Operating costs reflect the scale-back of certain retail gas marketing operations in 2002 as well as lower allocations for corporate support services in 2003.

Variations in margins reflect: 1) the settling or monetizing of certain in-the-money derivative contracts in 2003, 2) a change in the method of accounting for our gas in inventory in January 2003, and 3) volatility related to the accounting for our production-related gas supply contracts in 2001.

We monetized certain in-the-money derivative contracts in 2003 while simultaneously entering into replacement at-the-market contracts with various counterparties. The monetizations were completed in conjunction with implementing a series of initiatives to improve cash flow as well as our ability to fully utilize Section 29 tax credits (Note 13). The monetizations had the impact of reducing unrealized gains and increasing realized gains by approximately $136 million, with no significant impact on earnings.

As previously discussed, our derivative financial instruments are accounted for under the mark to market method, including those derivatives that hedge our price risk exposure associated with gas in inventory. Through December 2002, our physical gas in inventory was marked to the current spot price under fair value accounting rules. Accordingly, mark to market accounting for derivatives, coupled with fair value accounting for gas in inventory, minimized earnings mismatches. To comply with new accounting requirements resulting from the rescission of Emerging Issues Task Force (EITF) Issue No. 98-10, *"Accounting for Contracts Involved in Energy Trading and Risk Management Activities*," we changed to the average cost method for our gas inventories, effective January 2003 (Note 2). As a result, CoEnergy experienced earnings volatility as it recorded unrealized gains in 2002 and unrealized losses in 2001 from fair valuing its inventory, whereas no such gains or losses were recorded in 2003.

The comparability of CoEnergy's results was also affected by using different market prices for fair valuing its derivatives and fair valuing its gas in inventory, before the accounting change. Derivatives are marked to market against the forward curve, whereas gas in inventory was marked to the current spot price. The difference in accounting for derivatives and gas in storage resulted in earnings volatility in 2002 and 2001 when price changes in the spot month did not correspond with those in the forward market. Gas in storage in December 2002 was priced at a spot market rate of $5.10 Mcf, compared to $2.77 per Mcf in December 2001 and a May 31, 2001, acquisition date rate of $4.10 per Mcf. Significantly smaller changes in forward prices occurred during these same periods. As a result, the mark-to-market gains and losses on gas inventory were only partially offset by mark-to-market losses and gains on the storage-related derivatives.

CoEnergy receives gas produced from DTE Energy's Gas Production operations, which is used to meet its commitments under long-term contracts with cogeneration customers. The gas produced does not qualify for mark-to-market accounting. CoEnergy recorded a gain in 2001 totaling approximately $50 million, net of taxes, primarily attributable to marking to market sales contracts with power generation customers without recording an offsetting loss from marking to market the production-related gas supply. In December 2001, CoEnergy entered into hedge transactions that substantially mitigate the earnings volatility related to the gas contracts with power generation customers **.**

Outlook – Energy Marketing & Trading will seek to manage its business in a manner consistent with and complementary to the growth of our other business segments. Gas storage and transportation capacity enhances our ability to provide reliable and custom-tailored bundled services to large-volume end users and utilities. This capacity, coupled with the synergies from DTE Energy's other businesses, positions the segment to add value.

Significant portions of the Energy Marketing & Trading portfolio are economically hedged, and include financial instruments, gas inventory, as well as owned and contracted natural gas pipelines and storage assets. These financial instruments are deemed derivatives whereas the gas inventory, pipelines and storage assets are not considered derivatives for accounting purposes. As a result, Energy Marketing & Trading will experience earnings volatility as derivatives are marked to market without revaluing the underlying non-derivative contracts and assets.

A significant portion of the earnings volatility in this segment is associated with the natural gas storage cycle, which runs from June to March. Injections of gas into inventory takes place in the summer and gas is withdrawn in the winter. DTE Energy's policy is to hedge the price risk of all purchases for storage with sales in the "over the counter" and futures markets, eliminating the price risk for the storage business. As previously discussed, current accounting rules do allow for the marking to market of forward sales, but do not allow for the marking to market of the related gas inventory. This results in gains and losses that are recognized in different interim periods, but even out by the end of the storage cycle.

In February 2004, we terminated a long-term gas exchange agreement and modified our future purchase commitments under a related transportation agreement with an interstate pipeline company, effective March 31, 2004. The agreements were at rates that were not reflective of current market conditions and had been fair valued under generally accepted accounting principles. In 2002, the fair value of the transportation agreement was frozen when it no longer met the definition of a derivative as a result of FERC Order 637. The fair value amounts were being amortized to income over the life of the related agreements, representing a net liability of approximately $75 million as of December 31, 2003. We are currently negotiating new agreements with the interstate pipeline company. We will record an appropriate adjustment to the liability after all related agreements have been finalized.

Non-regulated - Other

Our other non-regulated businesses are comprised of our Coal Services and Biomass units. Coal Services provides fuel, transportation and equipment management services. We specialize in minimizing energy production costs and maximizing reliability of supply for energy-intensive customers. Additionally, we participate in coal trading and coal-to-power tolling transactions, as well as sales of excess emissions credits. Coal Services has formed a subsidiary, DTE PepTec Inc., that uses proprietary technology to produce high quality coal products from fine coal slurries that are typically discarded from coal mining operations. Biomass develops, owns and operates landfill recovery systems in the U.S. Gas produced from these landfill sites qualifies for Section 29 tax credits.

Factors impacting income: Earnings declined $9 million in 2003 and increased $1 million in 2002. The 2003 decline reflects reduced marketing and tolling income as well as an increase in operating costs associated with ramping up the DTE PepTec business. Our first waste coal facility in Ohio became operational in late-2003.

(Dollars in Millions)	2003	2002	2001
Coal Services			
Tons of coal shipped (in millions)	**32.0**	28.5	23.5
Biomass			
Gas Produced (in Bcf)	**26.8**	27.5	24.2
Tax Credits Generated (1)	**$10.5**	$12.9	$ 11.9

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

Outlook – We expect to continue to grow our Coal Services and Biomass units. We believe a substantial market exists for the use of DTE PepTec Inc. technology and plan to aggressively pursue expansion opportunities. We expect to open 3 to 5 operating sites in 2004. Biomass currently has 31 operating sites and other projects under development. Section 29 tax credits related to Biomass operations expire in 2007.

ENERGY DISTRIBUTION

Power Distribution

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

(in Millions)	2003	2002	2001
Operating Revenues	**$1,247**	$1,343	$1,256
Fuel and Purchased Power	**(19)**	(26)	(10)
Operation and Maintenance	**(724)**	(649)	(511)
Depreciation, Depletion and Amortization	**(249)**	(246)	(246)
Taxes Other Than Income	**(100)**	(117)	(120)
Merger and Restructuring Charges	—	—	(114)
Operating Income	**155**	305	255
Other Income and (Deductions)	**(128)**	(136)	(132)
Income Tax Provision	**(10)**	(58)	(26)
Net Income	**$ 17**	$ 111	$ 97
Operating Income as a Percent of Operating Revenues	**12%**	23%	20%

Factors impacting income: Power Distribution earnings decreased $94 million during 2003 and increased $14 million in 2002, compared to the prior year. As subsequently discussed, these results primarily reflect changes in operating revenues and increased operation and maintenance expenses. Merger and restructuring charges associated with the 2001 MCN Energy acquisition also impacted the comparability of results.

Operating revenues declined $96 million in 2003 primarily due to mild summer weather and the impact of slower economic conditions affecting commercial and industrial sales. Operating revenues increased $87 million in 2002 reflecting higher residential sales attributable to greater cooling demand.

Below are volumes associated with the regulated power distribution business:

(in Thousands of MWh)	2003	2002	2001
Electric Deliveries			
Residential	**15,074**	15,958	14,503
Commercial	**15,942**	18,395	18,777
Industrial	**12,254**	13,590	14,430
Wholesale	**2,241**	2,249	2,159
	45,511	50,192	49,869
Electric Choice	**7,281**	3,510	1,268
Total Electric Deliveries	**52,792**	53,702	51,137

Operation and maintenance expense increased $75 million in 2003 and $138 million in 2002 reflecting higher costs associated with weather-related power outages, employee benefits, uncollectable accounts receivables, allocations for corporate support services, and customer service initiatives to improve customer satisfaction. Restoration costs associated with three catastrophic storms in 2003 and the August 2003 blackout totaled $76 million. We experienced an April ice storm, resulting in more than 400,000 customers losing power, a July windstorm, affecting over 190,000 customers, a November windstorm, affecting 160,000 customers, and the August blackout, affecting all 2.1 million of our customers. This compares with $49 million in costs in 2002 related to two catastrophic storms, as well as heat-related maintenance expenses due to prolonged periods of above normal summer temperatures and the related stress placed on our distribution system.

Employee pension and health care benefit costs increased $26 million in 2003 and $12 million in 2002 due to recent financial market performance, lower discount rates and increased health care trend rates. Uncollectable accounts expense increased $17 million in 2003 and decreased $1 million in 2002 reflecting higher past due amounts attributable to current economic conditions. Additionally, results for

2003 also reflect costs associated with customer service initiatives and a net of tax loss of $14 million on the sale of our non-strategic steam heating business (Note 3). Partially offsetting these increases were benefits from the DTE Operating System, as previously discussed, and lower employee incentive costs.

Taxes other than income decreased $17 million in 2003 and $3 million in 2002. The decline in 2003 is due to lower Michigan Single Business Taxes, reflecting reduced taxable earnings, and lower property taxes.

Outlook – Operating results are expected to vary as a result of external factors such as weather, changes in economic conditions and the severity and frequency of storms. Economic conditions and prior billing issues have resulted in an increase in past due receivables. We believe our allowance for doubtful accounts is based on reasonable estimates. However, failure to make continued progress in collecting our past due receivables would unfavorably affect operating results. As a result, we have organized a focused effort to address the credit and collection issues.

We experienced numerous catastrophic storms over the past few years. The effect of the storms on annual earnings ranged up to $70 million and was partially offset by storm insurance. We were unable to obtain storm insurance at economical rates in 2004 and as a result, we do not anticipate having insurance coverage at levels that would significantly offset unplanned expenses from ice storms, tornadoes, or high winds that damage our distribution infrastructure.

As previously mentioned, Detroit Edison filed a rate case in June 2003 to address future operating costs and other issues. Detroit Edison received an interim order in this rate case in February 2004. See Note 4 – Regulatory Matters.

Non-Regulated

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

Factors impacting income: Non-regulated losses decreased $1 million in 2003 and increased $6 million in 2002. The slight improvement in 2003 is due primarily to increased sales and cost reductions.

Outlook – Although installed capacity for DTE Energy Technologies is increasing, the growth in this business is below our expectations. Accordingly, we have taken actions to reduce our expenses and streamline our operations, including exiting from some non-strategic business lines and activities. DTE Energy Technologies expects to continue participating in the emerging distributed generation market.

Table of Contents

ENERGY GAS

Gas Distribution

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

(in Millions)	2003	2002	2001*
Operating Revenues	**$1,498**	$1,369	$ 615
Fuel and Purchased Power	**(909)**	(774)	(304)
Gross Margins	**589**	595	311
Operation and Maintenance	**(371)**	(297)	(194)
Depreciation, Depletion and Amortization	**(101)**	(104)	(61)
Taxes Other Than Income	**(52)**	(51)	(24)
Merger and Restructuring Charges	**—**	—	(81)
Operating Income (Loss)	**65**	143	(49)
Other Income and (Deductions)	**(36)**	(41)	(38)
Income Tax Benefit (Provision)	**—**	(36)	49
Net Income (Loss)	**$ 29**	$ 66	$ (38)
Operating Income as a Percent of Operating Revenues	**4%**	10%	n/m%

* Reflects the operations of MichCon from the May 31, 2001 acquisition date.
n/m - not meaningful

Factors impacting income: Gas Distribution's earnings declined $37 million in 2003 and increased $104 million in 2002, compared to the prior year. As subsequently discussed, results in 2003 primarily reflect a decline in gross margins and increased operation and maintenance expenses. The significant improvement in 2002 reflects a full year of operations of MichCon, which was acquired in conjunction with the MCN Energy merger in May 2001. In contrast to 2001, the 2002 results include the January through April period when demand for natural gas is at its highest. Merger and restructuring charges associated with the merger also impacted the comparability. The pro-forma impact of the MCN Energy acquisition on DTE Energy is discussed in Note 3 – Acquisitions and Dispositions.

Gross margins declined $6 million in 2003 reflecting a $26.5 million reserve for the potential disallowance in gas costs pursuant to a March 2003 MPSC order in MichCon's 2002 GCR plan case (Note 4). The impact of the reserve was significantly offset by increased sales due to colder winter weather in early 2003.

Operation and maintenance expense increased $74 million in 2003 reflecting higher costs associated with employee benefits, uncollectable accounts receivables, allocations for corporate support services, and customer service initiatives. Employee pension and health care benefit costs increased $47 million in 2003 and uncollectable accounts expense increased $17 million in 2003 reflecting economic conditions and higher gas prices. Partially offsetting these increases were benefits from the DTE Operating System, as previously discussed, and lower employee incentive costs.

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

Outlook – Operating results are expected to vary as a result of external factors such as regulatory proceedings, weather and changes in economic conditions. Higher gas prices, current economic conditions and prior billing issues have resulted in an increase in past due receivables. We believe our allowance for doubtful accounts is based on reasonable estimates. However, failure to make continued progress in collecting our past due receivables would unfavorably affect operating results. As previously discussed, we are focused on addressing the credit and collection issues.

The MPSC issued several orders that continue the gas Customer Choice program on a permanent basis. 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. As of December 2003, approximately 129,000 customers were participating in the gas Customer Choice program, compared with approximately 190,000 customers as of December 2002.

As a result of the continued increase in operating costs, MichCon filed a rate case in September 2003 to increase rates by $194 million annually to address future operating costs and other issues. See Note 4 – Regulatory Matters.

Non-regulated

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

Factors impacting income: Earnings increased $3 million in 2003 and $15 million in 2002. The 2003 earnings improvement primarily reflects the gain from the sale of our 16% pipeline interest in the Portland Natural Gas Transmission System. The 2002 results reflect a full year of operations of the our non-regulated gas businesses that were acquired in conjunction with the MCN Energy acquisition in May 2001.

Outlook – We expect to further develop our gas production properties in northern Michigan and our pipelines, processing and storage assets to support other DTE Energy businesses. In October 2003, we acquired an additional 15% interest in the Vector Pipeline, bringing our total ownership interest to 40%. The purchase of the additional interest in the Vector Pipeline complements our existing gas distribution and storage facilities in Michigan. Additionally, we expect to continue to invest in opportunities in the coal bed methane business to leverage our production, coal and low cost operating capabilities.

CORPORATE & OTHER

Corporate & Other includes the administrative and general expenses of various corporate support functions such as accounting, legal and information technology. As these functions essentially support the entire company, they are allocated to the various segments based on services utilized and therefore can vary from year to year. Additionally, Corporate & Other holds certain non-regulated debt and investments, including assets held for sale and in emerging energy technologies.

Factors impacting income: Corporate & Other’s losses were basically flat in 2003 and 2002. The 2003 results were affected by a $15 million cash contribution to the DTE Energy Foundation that was funded with proceeds received from the sale of ITC (Note 3). The impact of the contribution was offset by lower interest costs. Results in 2002 reflect higher interest expense resulting from increased debt and a full year’s impact of corporate debt assumed in the MCN Energy acquisition. Additionally, 2002 results reflect a reserve of $11 million (pre-tax) for the possible loss associated with direct loans to and the guarantee of debt of a technology investment. Losses in 2001 include the amortization of goodwill associated with the MCN Energy acquisition.

DISCONTINUED OPERATIONS - ITC

In December 2002, we entered into a definitive agreement with an affiliate of Kohlberg Kravis Roberts & Co. and Trimaran Capital Partners, LLC to sell ITC for $610 million in cash. The sale closed on February 28, 2003 following approval of the transaction by the FERC and resolution of all other contingencies and generated a net of tax gain of $63 million.

Prior to May 31, 2001, Detroit Edison owned and operated the transmission assets of ITC, which were vertically integrated with its other operations. Accordingly, revenues, expenses and cash flows associated with these transmission assets were bundled with Detroit Edison’s Power Distribution operations. Significant changes in regulation over the past few years required Detroit Edison to cede operating control of its transmission assets to an independent system operator or to sell its transmission assets. In response to these new requirements we formed ITC and transferred our transmission assets to this wholly-owned subsidiary with the intent of divesting ITC. Effective June 1, 2001, the transmission assets of ITC were transferred to DTE Corporate and its revenues, expenses and cash flows were separately monitored to measure its financial and operating performance. Accordingly, the presentation of discontinued operations in the consolidated statement of operations reflects the results of ITC after May 31, 2001. The financial results of the transmission business prior to June 1, 2001 are included as part of the Power Distribution segment.

CUMULATIVE EFFECT OF ACCOUNTING CHANGES

As required by generally accepted accounting principles, on January 1, 2003, we adopted new accounting rules for asset retirement obligations and energy trading activities. The cumulative effect of adopting these new accounting rules reduced 2003 earnings by $27 million. Additionally, on January 1, 2001 we adopted a new accounting rule for derivative instruments and the cumulative effect of adopting this new rule increased 2001 earnings by $3 million. See Note 2 for further discussion.

CAPITAL RESOURCES AND LIQUIDITY

(in Millions)	2003	2002	2001
Cash and Cash Equivalents			
Cash Flow From (Used For)			
Operating activities:			
Net income	**$ 521**	$ 632	$ 332
Depreciation, depletion and amortization	**691**	759	795
Merger and restructuring charges	**—**	—	215
Deferred income taxes	**(220)**	(208)	(7)
Gain on sale of assets, net	**(129)**	—	—
Working capital and other	**87**	(187)	(524)
	950	996	811
Investing activities			
Plant and equipment expenditures – regulated	**(679)**	(794)	(776)
Plant and equipment expenditures – non-regulated	**(72)**	(190)	(320)
Proceeds for sale of ITC, synfuels and other assets	**758**	41	216
Acquisition of MCN Energy	**—**	—	(1,212)
Restricted cash and other investments	**3**	(172)	(194)
	10	(1,115)	(2,286)
Financing activities			
Issuance of long-term debt and common stock (1)	**571**	1,223	4,254
Redemption of long-term debt	**(1,208)**	(613)	(1,423)
Short-term borrowings, net	**(44)**	(267)	(282)
Repurchase of common stock	**(3)**	(9)	(438)
Other, primarily dividends on common stock	**(355)**	(350)	(432)
	(1,039)	(16)	1,679
Net Increase (Decrease) in Cash and Cash Equivalents	**$ (79)**	$ (135)	$ 204

(1) 2001 includes $1.75 billion of securitization bonds and $1.35 billion of debt issued to acquire MCN Energy.

Operating Activities

We use cash derived from operating activities to maintain and expand our electric and gas utilities and to grow our non-regulated businesses. In addition, we use cash from operations to retire long-term debt and pay dividends. A majority of the company's operating cash flow is provided by the two regulated utilities, which are significantly influenced by factors such as weather, customer choice sales loss, regulatory outcomes, economic conditions and operating costs. This part of our business has recently been under considerable financial pressure given that we have not had a rate increase in over 10 years, coupled with higher operating costs and increased regulatory deferrals. While these regulatory deferrals at Detroit Edison have served to mitigate some of the earnings pressures as a result of these influencing factors, the corresponding cash flows have been deferred. Our non-regulated businesses also provide sources of cash flow to the enterprise and reflect a range of operating profiles. These vary from our synthetic fuels business, which will provide substantial cash flow over the next 5 years, to new start-ups, such as our coal bed methane or waste coal recovery businesses, which are growing and will require modest investments beyond their cash generation capabilities.

During 2003, our consolidated net cash from operating activities was $950 million, reflecting a decrease of $46 million from 2002 levels. The decrease in 2003 operating cash flow was attributable to declines in regulated net income, after adjusting for noncash items (depreciation, depletion, amortization, deferred taxes and gains), reflecting the impacts of weather, lost electric Customer Choice margins and higher operating costs. Partially offsetting these declines were lower working capital and other requirements reflecting a company-wide initiative focused on improving cash flow. The initiative included better inventory management, improved accounts receivable collections, the selling of interests in our synfuel facilities, the monetization of in-the-money derivatives and replacing margin deposits with letters of credit. The improvement in working capital was achieved despite a $222 million contribution to our pension plan.

Operating cash flow in 2002 of $996 million was $185 million higher than 2001 levels, largely attributable to the full year's impact of the MCN Energy acquisition, which was completed in May 2001. Lower working capital and other requirements were partially offset by a decline in net income, after adjusting for noncash items. Working capital reflects the seasonal requirements of the gas business where cash is used in the second half of the year to finance increases in gas inventories and customer accounts receivable. Additionally, past due accounts receivable balances increased due to higher gas prices, economic conditions and conversion issues with the new combined utility billing system.

Outlook — We expect cash flow from operations to increase over the long-term, but to remain relatively the same in 2004 as 2003. Cash flow improvements from utility rate increases and synfuel sales will be offset by higher cash requirements primarily within our energy marketing and trading business.

Operating cash flow from our utilities is expected to increase in 2004, but will be affected by the level of sales migration under the electric Customer Choice program and the ability of the MPSC within the regulatory processes to put in place a Choice program that has sound economic fundamentals. In addition, the Choice program's impact will also be determined by the success of the company in addressing certain structural flaws within the legislative process. While the Choice program's shortfalls may be structurally addressed within these two processes, the use of regulatory deferrals by the MPSC might affect the cash benefits of addressing the existing choice program being realized in 2004.

Another factor affecting regulated cash flows is the degree and timing of rate relief within the electric and gas rate cases. Based on the interim order issued by the MPSC on February 20, 2004, approximately $71 million of additional revenues should be realized within the 2004 calendar year. Due to the structure of the interim rate order, we will not realize the full benefits of interim and final rate relief until 2006 when customer rate caps expire.

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

Cash flow from our synfuel business, including proceeds from the sale of interests in related facilities, should shift from a net cash loss of $195 million in 2003 to positive cash flow of $135 million in 2004 and $355 million in 2005. The expected improvements are driven by the sale of interests in synfuel facilities, increased production and a higher cash value per credit. We will also benefit from lower taxes paid as we use our tax credit carry forward position.

Our other operating non-regulated businesses will provide minimal cash from operations in 2004 and grow modestly in future years. Remaining start-up businesses such as coal bed methane, waste coal recovery and distributed generation will have cash losses over the next couple of years while they are being further developed. Certain of the cash initiatives previously discussed, resulted in accelerating the receipt of cash in 2003 which will have the impact of lowering cash flow in 2004.

Investing Activities

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

During 2003, we had net cash from investing activities of $10 million compared to cash used of $1.1 billion in 2002. The significant improvement was due to proceeds totaling $758 million from the sale of ITC, interests in three synfuel projects and non-strategic assets that were acquired as part of the MCN Energy acquisition. Additionally, regulated and non-regulated plant expenditures decreased significantly in 2003. Lower regulated expenditures of $115 million were associated with air quality regulations that require reductions in nitrogen oxide levels. Non-regulated expenditures declined by $118 million and the comparison reflects costs incurred in 2002 associated with four synfuel facilities that became fully operational.

During 2002, the investing activity cash flow comparison improved by $1.2 billion and was impacted by the cash portion of the MCN Energy acquisition in 2001. The 2002 improvement was also due to lower non-regulated capital expenditures, partially offset by reduced proceeds from the sale of assets.

Outlook — Our strategic direction anticipates base level capital investments and expenditures for existing businesses in 2004 ranging from $750 million to $1.0 billion. Our utilities plan to spend higher amounts of capital, but actual spending levels will be matched to available cash flows. Until our two rate cases are resolved, we will hold utility capital spending at 2003 levels.

Capital spending for general corporate purposes will increase in 2004 primarily as a result of our DTE2 initiative, as subsequently discussed. This project will require capital investments in 2004 and 2005 for new computer systems. Non-regulated capital spending will approximate $80 million to $100 million annually for the next several years. Capital spending for growth of existing or new businesses will be constrained in 2004 due to the pending rate cases, electric Customer Choice issues and rating agency concerns about these businesses. Accordingly, we are seeking to grow the business by making small investments in areas like coal bed methane and waste coal recovery. Utilizing this approach allows us to determine quarterly our spending levels, which will be based on capital and credit constraints.

Longer term, once the electric Choice issues are resolved and utility rate increases are fully phased in, we anticipate capital availability to return to historical levels. After the utilities return to financial health, we will continue to pursue opportunities to grow our businesses in a disciplined fashion. If we can find opportunities that meet our strategy and financial and risk criteria we will look to make investments. If we have the available cash flow and can’t find value creating investments, we intend to return that capital to shareholders and pay down debt.

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

Financing Activities

We continually evaluate our leverage targets to ensure that they are consistent with our objective to have a strong investment grade debt rating. Since our merger with MCN Energy in 2001, we have been successful in reducing our leverage. Given the present environment in our industry, the increase in regulatory assets, and the nature of the electric Customer Choice program and other uncertainties, we may need to further lower our leverage in the future.

Our strategy is to have a targeted debt portfolio blend as to fixed and variable interest rates and maturity. We have completed a number of refinancings over the past several years with the effect of extending the average maturity of our long-term debt. The extension of the average maturity was accomplished at interest rates which have lowered our debt costs. Variable rate debt is principally in the form of outstanding commercial paper. Additionally, we have interest rate derivatives that effectively converts fixed rate debt to variable rate debt. Variable rate debt represents approximately 10% of our total debt outstanding as of December 31, 2003.

Our net cash related to financing activities decreased $1.0 billion in 2003 and decreased $1.7 billion in 2002. The 2003 change was due to higher redemptions of long-term debt and lower proceeds from issuances of new debt and common stock. In 2002, proceeds from the issuance of debt and common stock were used for the redemption of higher cost debt and to reduce short-term borrowings. The 2001 issuance of $1.75 billion of securitization bonds and the 2001 issuance of $1.35 billion of long-term debt to finance the acquisition of MCN Energy impacts the comparison between 2002 and 2001. In 2001, proceeds from the issuance of securitization bonds and other Detroit Edison and MichCon debt were used to repay higher priced debt and repurchase our common stock. Details of 2003 financing activities follows (Note 9):

- MichCon issued $200 million of 5.7% senior notes due in March 2033. The proceeds were used for debt redemption and general corporate purposes.

- DTE Energy issued $400 million of 6-3/8% senior notes due in April 2033. In conjunction with this issuance, DTE Energy exchanged $100 million principal amount of existing debt due April 2008. The proceeds were used for debt redemptions and general corporate purposes.

- DTE Energy redeemed $100 million principal amount of 6.17% Remarketed Notes due in 2038.

- Detroit Edison issued $49 million of 5.5% tax exempt bonds due in 2030. The proceeds were used to redeem $49 million of 6.55% tax-exempt bonds due 2024.

Outlook — Our goal is to maintain a healthy balance sheet. We intend on maintaining a high investment grade credit rating and maintaining leverage in the 50% to 55% range (excluding certain debt, principally securitization debt).

We expect to contribute $170 million of DTE Energy common stock to our pension plan in the first quarter of 2004. This contribution will modestly improve our leverage. Additionally, we expect to continue the practice of issuing new DTE Energy shares for our dividend reinvestment plan. We believe this is a cost-effective means of raising new equity.

Debt maturing in 2004 totals approximately $500 million and we called $100 million of Trust preferred- linked securities in late 2003. In addition, there are outstanding debt instruments that are likely to be economic to redeem and refund with new debt in 2004. The Company expects to continue to take advantage of low historical long-term interest rates and issue new securities with a longer life than the securities maturing or called.

As of December 31, 2003, DTE Energy, Detroit Edison and MichCon have effective shelf registrations with the SEC that allow for the issuance of up to an additional $1.3 billion of debt and $850 million of equity securities. We have authorization from the DTE Energy Board to repurchase approximately 9.5 million shares of our common stock. No shares have been repurchased under this authorization since early 2002. Future repurchases are not presently contemplated and will depend upon future market conditions and the Company's financial condition.

In October 2003, DTE Energy, Detroit Edison and MichCon entered into separate revolving credit facilities with a syndicate of banks totaling $1.3 billion. These facilities support our use of letters of credit and the issuance of commercial paper. Borrowing available under these revolving credit facilities totaled $1.2 billion as of December 31, 2003. Our revolving credit facilities contain customary covenants, including the requirement to maintain a debt to total capitalization ratio of not more than .65 to 1, and an "earnings before interest, taxes, depreciation and amortization" (EBITDA) to interest ratio of no less than 2 to 1. As of December 31, 2003, our debt to total capitalization ratio as computed under the terms of the agreement was .50 to 1 and our EBITDA to interest ratio was 3.6 to 1. We anticipate having the need and the ability to renew these credit facilities prior to their expiration at fair and reasonable market rates as determined at the time of negotiation.

Additionally, Detroit Edison has a $200 million short-term financing agreement secured by customer accounts receivable of which $100 million was outstanding as of December 31, 2003. The agreement contains certain covenants related to the delinquency of accounts receivable. Detroit Edison is currently in compliance with these covenants.

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

Contractual Obligations

The following table details our contractual obligations for debt redemptions, leases, purchase obligations and other long-term obligations as of December 31, 2003.

(in Millions) Contractual Obligations	Total	Less Than 1 Year	1-3 Years	4-5 Years	After 5 Years
Long-Term Debt:					
Mortgage bonds, notes & other	$ 6,006	$ 382	$ 1,054	$ 564	$4,006
Securitization bonds	1,585	89	312	252	932
Equity-linked securities	185	7	178	—	—
Trust preferred-linked securities	289	103	—	—	186
Capital lease obligations	109	12	36	22	39

Operating leases	757	72	182	92	411
Electric, gas, fuel, transportation & storage purchase obligations	10,228	4,269	3,292	1,219	1,448
Other long-term obligations	802	203	289	161	149
Total Obligations	$19,961	$ 5,137	$ 5,343	$2,310	$ 7,171

Credit Ratings

The uncertainty in Michigan's regulatory environment and the impact of the electric Customer Choice program has resulted in various independent credit rating agencies reviewing our credit rating. An unfavorable change in our rating could restrict our ability to access capital markets at attractive rates and increase our borrowing costs. We have issued guarantees for the benefit of various non-regulated subsidiaries. In the event that our credit rating is downgraded two levels and would therefore be below investment grade, certain of these guarantees would require us to post cash or letters of credit valued at approximately $290 million at December 31, 2003. Additionally, our trading business could be required to cease operations and our access to the short-term commercial paper market would be restricted or eliminated. While we currently do not anticipate such a downgrade, we cannot predict the outcome of current or future reviews. The following table shows our credit rating as determined by three nationally respected credit rating agencies. All ratings are considered investment grade and affect the value of the related securities.

		Credit Rating Agency		
		Standard & Poors	Moody's Investors Service	Fitch Ratings
DTE Energy	Senior Unsecured Debt	BBB *	Baa2 *	BBB
Detroit Edison	Senior Secured Debt	A- *	A3 *	A-
MichCon	Senior Secured Debt	BBB+ *	A2 **	A

* Currently on negative outlook

** Currently being reviewed for possible downgrade

CRITICAL ACCOUNTING ESTIMATES

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

Regulation

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

(in millions) Regulated Entity	
Detroit Edison (1)	$(18)
MichCon	(40)
Total	$(58)

(1) Excludes securitized regulatory assets

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

Risk Management and Trading Activities

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

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

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

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

Section 29 Tax Credits

We have generated Section 29 tax credits from our synfuel, coke battery, biomass and gas production operations. All of our synthetic fuel facilities have received favorable private letter rulings from the IRS with respect to their operations. All Section 29 tax credits taken after 1997 are subject to audit by the IRS, and if we fail to prevail through the administrative and legal process, there could be a significant tax liability owed for previously taken Section 29 tax credits. Four of our synfuel facilities are under audit by the IRS for 2001 and are expected to be completed in 2004. Our portion of tax credits generated was $241 million in 2003 as compared to $250 million in 2002 and $165 million in 2001. Outside firms assist us in assuring we operate in accordance with our private letter rulings and within the parameters of the law, as well as calculating the value of tax credits.

Goodwill

Certain of our business units have goodwill resulting from purchase business combinations (Note 1). In accordance with SFAS No. 142, "*Goodwill and Other Intangible Assets,*" each of our reporting units with goodwill is required to perform impairment tests annually or whenever events or circumstances indicate that the value of goodwill may be impaired. In order to perform these impairment tests, we must determine the reporting unit's fair value using valuation techniques, which use estimates of discounted future cash flows to be generated by the reporting unit. These cash flow estimates involve judgments based on a broad range of information and historical results. To the extent estimated cash flows are revised downward, the reporting unit may be required to write down all or a portion of its goodwill which would adversely impact our earnings. Based on our 2003 goodwill impairment test, we determined that no impairment existed. As of December 31, 2003, our goodwill totaled $2.1 billion.

Pension and Postretirement Costs

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

We had pension costs for qualified pension plans of $47 million in 2003, pension income of $9 million in 2002 and pension costs of $159 million in 2001. Postretirement benefits costs for all plans was $118 million in 2003, $70 million in 2002 and $104 million in 2001. Pension and postretirement benefits cost is calculated based upon a number of actuarial assumptions, including an expected long-term rate of return on our plan assets of 9.0% at December 31, 2003. In developing our expected long-term rate of return assumption, we evaluated input from our consultants, including their review of asset class risk and return expectations as well as inflation assumptions. Projected returns by such consultants are based on broad equity and bond markets. Our expected long-term rate of return on plan assets is based on an asset allocation assumption utilizing active investment management of 65% in equity markets, 28% in fixed income markets, and 7% invested in other assets. Because of market volatility, we periodically review our asset allocation and rebalance our portfolio when considered appropriate. Given market conditions we believe that 9.0% is a reasonable long-term rate of return on our plan assets. We will continue to evaluate our actuarial assumptions, including our expected rate of return, at least annually.

We base our determination of the expected return on qualified plan assets on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation recognizes changes in fair value in a systematic manner over a three-year period. Because of this method, the future value of assets will be impacted as previously deferred gains or losses are recorded. We have unrecognized net losses due to the recent unfavorable performance of the financial markets. As of December 31, 2003, we had $7 million of cumulative losses that remain to be recognized in the calculation of the market-related value of assets.

The discount rate that we utilize for determining future pension and postretirement benefit obligations is based on a review of bonds that receive one of the two highest ratings given by a recognized rating agency. The discount rate determined on this basis has decreased from 6.75% at December 31, 2002 to 6.25% at December 31, 2003. Due to recent financial market performance, lower discount rates and increased health care trend rates, we estimate that our 2004 pension costs will approximate $100 million compared to $54 million in 2003 and our 2004 postretirement benefit costs will approximate $135 million compared to $118 million in 2003. We have made modifications to the pension and postretirement benefit plans to mitigate the earnings impact of higher costs. Future actual pension and postretirement benefit costs will depend on future investment performance, changes in future discount rates and various other factors related to plan design.

Lowering the expected long-term rate of return on our plan assets by 1.0% would have increased our 2003 qualified pension costs by approximately $22 million. Lowering the discount rate and the salary increase assumptions by 1.0% would have increased our pension costs for 2003 by approximately $11 million. Lowering the health care cost trend assumptions by 1.0% would have decreased our postretirement benefit service and interest costs for 2003 by approximately $16 million.

The market value of our pension and postretirement benefit plan assets has been affected by declines in the financial markets in recent years. The value of our plan assets decreased from $2.8 billion at December 31, 2001, to $2.4 billion at December 31, 2002. The value at December 31, 2003 increased to $2.9 billion. The investment performance returns and declining discount rates required us to recognize at December 31, 2002, an additional minimum pension liability of $855 million, an intangible asset of $57 million and an entry to other comprehensive loss (shareholders' equity) of $518 million, net of tax. As of December 31, 2003, we recognized a decrease in minimum pension liability of $75 million, a decrease in intangible assets of $13 million and a decrease in other comprehensive loss (a component of shareholders' equity) of $647 million ($421 million after tax). The additional minimum pension liability and related accounting entries will be reversed on the balance sheet in future periods if the fair value of plan assets exceeds the accumulated pension benefit obligations. The recording of the minimum pension liability does not affect net income or cash flow.

Pension and postretirement costs and pension cash funding requirements will increase in future years without a substantial recovery in the financial markets. We made a $35 million cash contribution to the pension plan in 2002 and a $222 million cash contribution in 2003. We anticipate making an approximate $170 million contribution to our pension plan in the form of DTE Energy common stock in the first quarter of 2004. We also contributed $33 million to the postretirement plans in 2002. We did not contribute to the postretirement plans in 2003, and made a $40 million contribution in January 2004.

In December 2003, the Medicare Prescription Drug, Improvement and Modernization Act was signed into law. This Act provides for a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to the benefit established by law. We have not quantified the impact of the Act, if any, on our plan.

Allowance for Doubtful Accounts

We establish an allowance for doubtful accounts based upon factors surrounding the credit risk of specific customers, historical trends, economic conditions, age of receivables and other information. With the implementation of a new integrated utility billing system in late 2001, we encountered billing issues as is typical with large-scale system implementations. While we have resolved the primary billing issues, we may encounter difficulty in collecting past due receivables. Higher customer bills due to increased gas prices, the lack of adequate levels of assistance for low-income customers and economic conditions have also contributed to the increase in past due receivables. As a result of these factors, our allowance for doubtful accounts increased in 2002 and 2003. We believe the allowance for doubtful accounts is based on reasonable estimates. However, failure to make continued progress in collecting our past due receivables would unfavorably affect operating results and cash flow.

ENVIRONMENTAL MATTERS

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

The EPA ozone transport regulations and final new air quality standards relating to ozone and particulate air pollution will continue to impact us. Detroit Edison has spent approximately $560 million through December 2003 and estimates that it will spend approximately $40 million in 2004 and incur up to an additional $1.2 billion of future capital expenditures over the next five to eight years to satisfy both existing and proposed new control requirements. Recovery of costs to be incurred through December 2004 is included in our June 2003 electric rate case. In addition, we maintain the option to securitize these costs after the completion of our current regulatory proceedings.

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

DTE ENERGY OPERATING SYSTEM AND DTE2

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

In 2003, we began the implementation of DTE2, a company-wide initiative to improve existing processes and to implement new core information systems including, finance, human resources, supply chain and work management. We expect to incrementally spend approximately $150 million to $175 million over the next 3 to 4 years to implement these new processes and systems. We expect the benefits to outweigh this investment primarily from lower costs, faster business cycles, repeatable and optimized processes, enhanced internal controls, improvements in inventory management and reductions in system support costs.

NEW ACCOUNTING PRONOUNCEMENTS

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

FAIR VALUE OF CONTRACTS

The following disclosures are voluntary and have been developed through efforts of the Committee of Chief Risk Officers, a working group of chief risk officers from companies active in both physical and financial energy trading and marketing. We believe the disclosures provide enhanced transparency of the activities and position of our Energy Trading & Marketing segment.

Roll-Forward of Mark to Market Energy Contract Net Assets

The following table provides details on changes in our mark to market (MTM) net asset or (liability) position during 2003.

(in Millions)	Proprietary Trading (1)	Structured Contracts (2)	Owned Assets (3)	Energy Trading Total	Gas Production	Total
Energy Marketing & Trading Segment						
MTM at December 31, 2002	$ 15	$ 19	$ (50)	$ (16)	$ (79)	$ (95)
Reclassed to realized upon settlement	(5)	(15)	14	(6)	27	21
Liquidation of in-the-money positions (4)	—	—	(136)	(136)	—	(136)
Changes in fair value	11	12	(16)	7	—	7
Amortization of option premiums	(9)	—	—	(9)	—	(9)
Amounts impacting unrealized income	(3)	(3)	(138)	(144)	27	(117)
Cumulative effect adjustment (5)	(2)	(1)	17	14	-*	14
Effective portion of change in fair value	—	2	—	2	(28)	(26)
MTM at December 31, 2003	$ 10	$ 17	$ (171)	$(144)	$ (80)	$(224)

(1) "Proprietary Trading" represents derivative activity transacted with the intent of capturing profits on forward price movements.

(2) "Structured Contracts" represent derivative activity transacted with the intent to capture profits by originating substantially hedged positions with wholesale energy marketers, utilities, retail aggregators and end-users. Although transactions are generally executed with a buyer and seller simultaneously, some positions remain open until a suitable offsetting trade can be executed.

(3) "Owned Assets" represent derivative activity associated with assets owned by DTE Energy, including forward sales of gas production and trades associated with owned transportation and storage capacity. Derivatives are generally executed with the intent of locking in and optimizing profits without creating additional risk.

(4) In conjunction with our overall tax planning and cash initiatives, we monetized certain in-the-money contracts in 2003 while simultaneously entering into at-the-market contracts with various counterparties. This had the impact of optimizing taxable income and cash flow while having minimal impact on reported earnings.

(5) Excludes the cumulative effect adjustment associated with the change in accounting for gas inventory (Note 2).

(in Millions)	Proprietary Trading	Structured Contracts	Owned Assets	Eliminations	Energy Trading Total	Gas Production	Total Assets (Liabilities)
Current assets	$ 91	$ 44	$ 98	$ (45)	$ 188	$ —	$ 188
Noncurrent assets	13	27	57	(7)	90	—	90
Total MTM assets	104	71	155	(52)	278	—	278
Current liabilities	(79)	(32)	(219)	44	(286)	(42)	(328)
Noncurrent liabilities	(15)	(22)	(107)	8	(136)	(38)	(174)
Total MTM liabilities	(94)	(54)	(326)	52	(422)	(80)	(502)
Total MTM net assets (liabilities)	$ 10	$ 17	$ (171)	$ —	$ (144)	$ (80)	$ (224)

Maturity and source of fair value of MTM energy contract net assets

We fully reserve all unrealized gains and losses related to periods beyond the liquid time frame. Our intent is to recognize MTM activity only when pricing data is obtained from active quotes and published indexes. The table below shows the maturity of the MTM positions of our energy contracts.

(in Millions) Source of Fair Value	2004	2005	2006	2007 and Beyond	Total Fair Value
Proprietary Trading	$ 13	$ (3)	$ —	$ —	$ 10
Structured Contracts	11	5	—	1	17
Owned Assets	(121)	(39)	(11)	—	(171)
Energy Marketing & Trading	(97)	(37)	(11)	1	(144)
Gas Production	(42)	(30)	(8)	—	(80)
Total	$(139)	$(67)	$(19)	$ 1	$(224)

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

DTE Energy has commodity price risk arising from market price fluctuations in conjunction with the anticipated purchase of electricity to meet its obligations during periods of peak demand. We also are exposed to the risk of market price fluctuations on gas sale and purchase contracts, gas production and gas inventories. To limit our exposure to commodity price fluctuations, we have entered into a series of electricity and gas futures, forwards, option and swap contracts. See Note 15 – Financial and Other Derivative Instruments for further discussion.

Interest Rate Risk

DTE Energy is subject to interest rate risk in connection with the issuance of debt and preferred securities. In order to manage interest costs, we use treasury locks and interest rate swap agreements. Our exposure to interest rate risk arises primarily from changes in U.S. Treasury rates, commercial paper rates and London Inter-Bank Offered Rates (LIBOR).

Foreign Currency Risk

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

Summary of Sensitivity Analysis

We performed a sensitivity analysis calculating the impact of changes in fair values utilizing applicable forward commodity rates or changes in interest rates if they occurred at December 31, 2003:

(in Millions) Activity	Increase of 10%	Decrease of 10 %	Change in the fair value of
Gas Contracts	$ (8)	$ 9	Commodity contracts
Power Contracts	$ (8)	$ 8	Commodity contracts
Interest Rate Risk	$ (303)	$ 323	Long term debt
Foreign Currency Risk	$ .2	$ (.2)	Forward contracts

Credit Risk

Bankruptcies

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

Energy Trading & CoEnergy Portfolio

We utilize both external and internally generated credit assessments when determining the credit quality of our trading counterparties. The following table displays the credit quality of our trading counterparties.

(in Millions)	Credit Exposure before Cash Collateral	Cash Collateral	Net Credit Exposure
Investment grade (1)			
A- and Greater	$ 215	$ (22)	$ 193
BBB+ and BBB	157		157
BBB-	3		3
Total Investment Grade	375	(22)	353
Non-investment grade (2)	4	(2)	2
Internally Rated - investment grade (3)	59	(3)	56
Internally Rated - non-investment grade (4)	4		4
Total	$ 442	$ (27)	$ 415

(1) This category includes counterparties with minimum credit ratings of Baa3 assigned by Moody’s Investor Service (Moody’s) and BBB- assigned by Standard & Poor’s Rating Group (Standard & Poor’s). The five largest counterparty exposures combined for this category represented 39% of the total gross credit exposure.

(2) This category includes counterparties with credit ratings that are below investment grade. The five largest counterparty exposures combined for this category represented less than 1% of the total gross credit exposure.

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

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

Item 8. Financial Statements and Supplementary Data

The following consolidated financial statements and schedules are included herein.

INDEPENDENT AUDITORS' REPORT

To the Board of Directors and Shareholders of
DTE Energy Company

We have audited the consolidated statement of financial position of DTE Energy Company and subsidiaries (the "Company") as of December 31, 2003 and 2002, and the related consolidated statements of operations, cash flows and changes in shareholders' equity and comprehensive income for each of the three years in the period ended December 31, 2003. Our audits also included the financial statement schedule listed in the index at Item 15. These financial statements and the financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the consolidated financial statements and the financial statement schedule based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of DTE Energy Company and subsidiaries at December 31, 2003 and 2002, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2003 in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements of the Company taken as a whole, presents fairly, in all material respects, the information set forth therein.

As discussed in Note 2 to the consolidated financial statements, in connection with the required adoption of certain new accounting principles, in 2003 the Company changed its method of accounting for asset retirement obligations, energy trading contracts and gas inventories; in 2002 the Company changed its method of accounting for goodwill and energy trading contracts; and in 2001 the Company changed its method of accounting for derivative instruments and hedging activities.

/s/ DELOITTE & TOUCHE LLP

Detroit, Michigan
March 1, 2004

Table of Contents

DTE Energy Company
Consolidated Statement of Operations

(in Millions, Except per Share Amounts)	Year Ended December 31 2003	2002	2001
Operating Revenues	**$ 7,041**	$6,729	$5,787
Operating Expenses			
Fuel, purchased power and gas	**2,241**	2,099	1,919
Operation and maintenance	**3,032**	2,547	1,848
Depreciation, depletion and amortization	**687**	737	782
Taxes other than income	**334**	352	305
Merger and restructuring charges (Note 3)	**—**	—	268
	6,294	5,735	5,122
Operating Income	**747**	994	665
Other (Income) and Deductions			
Interest expense	**546**	569	482
Interest income	**(37)**	(29)	(22)
Minority interest	**(91)**	(37)	—
Other income	**(138)**	(62)	(60)
Other expenses	**110**	51	75
	390	492	475
Income Before Income Taxes	**357**	502	190
Income Tax Benefit (Note 7)	**(123)**	(84)	(119)
Income from Continuing Operations	**480**	586	309
Income from Discontinued Operations of ITC, net of tax (Note 3)	**68**	46	20
Cumulative Effect of Accounting Changes, net of tax (Note 2)	**(27)**	—	3
Net Income	**$ 521**	$ 632	$ 332
Basic Earnings per Common Share (Note 8)			
Income from continuing operations	**$ 2.87**	$ 3.57	$ 2.02
Discontinued operations	**.41**	.28	.13
Cumulative effect of accounting changes	**(.17)**	—	.02
Total	**$ 3.11**	$ 3.85	$ 2.17
Diluted Earnings per Common Share (Note 8)			
Income from continuing operations	**$ 2.85**	$ 3.55	$ 2.01
Discontinued operations	**.40**	.28	.13
Cumulative effect of accounting changes	**(.16)**	—	.02
Total	**$ 3.09**	$ 3.83	$ 2.16
Average Common Shares			
Basic	**168**	164	153
Diluted	**168**	165	154
Dividends Declared per Common Share	**$ 2.06**	$ 2.06	$ 2.06

See Notes to Consolidated Financial Statements

DTE Energy Company
Consolidated Statement of Financial Position

(in Millions)	December 31 2003	December 31 2002
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 54**	$ 133
Restricted cash	**131**	237
Accounts receivable		
Customer (less allowance for doubtful accounts of $99 and $82, respectively)	**877**	902
Accrued unbilled revenues	**316**	296
Other	**338**	237
Inventories		
Fuel and gas	**467**	413
Materials and supplies	**162**	163
Assets from risk management and trading activities	**186**	224
Other	**181**	159
	2,712	2,764
Investments		
Nuclear decommissioning trust funds	**518**	417
Other	**601**	496
	1,119	913
Property		
Property, plant and equipment	**17,679**	17,862
Less accumulated depreciation and depletion (Note 2)	**(7,355)**	(7,320)
	10,324	10,542
Other Assets		
Goodwill (Note 3)	**2,067**	2,112
Regulatory assets (Note 4)	**2,063**	1,197
Securitized regulatory assets (Note 4)	**1,527**	1,613
Notes receivable	**469**	336
Assets from risk management and trading activities	**88**	152
Prepaid pension assets	**181**	172
Other	**203**	184
	6,598	5,766
Total Assets	**$20,753**	$19,985

See Notes to Consolidated Financial Statements

DTE Energy Company
Consolidated Statement of Financial Position

(in Millions, Except Shares)	December 31 2003	2002
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	**$ 625**	$ 647
Accrued interest	**110**	115
Dividends payable	**87**	90
Accrued payroll	**51**	49
Income taxes	**185**	44
Short-term borrowings	**370**	414
Current portion long-term debt, including capital leases	**477**	1,018
Liabilities from risk management and trading activities	**326**	262
Other	**648**	552
	2,879	3,191
Other Liabilities		
Deferred income taxes	**988**	916
Regulatory liabilities (Notes 2 and 4)	**817**	179
Asset retirement obligations (Note 2)	**866**	—
Asset removal costs (Note 2)	**—**	729
Unamortized investment tax credit	**156**	168
Liabilities from risk management and trading activities	**173**	208
Liabilities from transportation and storage contracts	**495**	545
Accrued pension liability	**345**	582
Deferred gains from asset sales	**311**	161
Minority interest	**156**	128
Nuclear decommissioning (Notes 2 and 5)	**67**	416
Other	**544**	394
	4,918	4,426
Long-Term Debt (net of current portion) (Note 9)		
Mortgage bonds, notes and other	**5,624**	5,656
Securitization bonds	**1,496**	1,585
Equity-linked securities	**185**	191
Trust Preferred-linked securities	**289**	289
Capital lease obligations	**75**	82
	7,669	7,803
Commitments and Contingencies (Notes 4, 5 and 13)		
Shareholders' Equity		
Common stock, without par value, 400,000,000 shares authorized, 168,606,522 and 167,462,430 shares issued and outstanding, respectively	**3,109**	3,052
Retained earnings	**2,308**	2,132
Accumulated other comprehensive loss	**(130)**	(619)
	5,287	4,565
Total Liabilities and Shareholders' Equity	**$20,753**	$19,985

See Notes to Consolidated Financial Statements

DTE Energy Company
Consolidated Statement of Cash Flows

(in Millions)	Year Ended December 31 2003	2002	2001
Operating Activities			
Net income	**$ 521**	$ 632	$ 332
Adjustments to reconcile net income to net cash from operating activities:			
Depreciation, depletion and amortization	**691**	759	795
Merger and restructuring charges	**—**	—	215
Deferred income taxes	**(220)**	(208)	(7)
Gain on sale of assets, net	**(129)**	—	—
Partners' share of synfuel project losses	**(78)**	(40)	—
Contributions from synfuel partners	**65**	22	—
Cumulative effect of accounting changes	**27**	—	3
Changes in assets and liabilities, exclusive of changes shown separately (Note 1)	**73**	(169)	(527)
Net cash from operating activities	**950**	996	811
Investing Activities			
Plant and equipment expenditures – regulated	**(679)**	(794)	(776)
Plant and equipment expenditures – non-regulated	**(72)**	(190)	(320)
Acquisition of MCN Energy, net of cash acquired	**—**	—	(1,212)
Proceeds from sale of interests in synfuel projects	**89**	32	—
Proceeds from sale of ITC and other assets	**669**	9	216
Restricted cash for debt redemptions	**106**	(79)	(70)
Other investments	**(103)**	(93)	(124)
Net cash from (used for) investing activities	**10**	(1,115)	(2,286)
Financing Activities			
Issuance of long-term debt	**527**	958	4,254
Redemption of long-term debt	**(1,208)**	(613)	(1,423)
Issuance of trust preferred-linked securities	**—**	180	—
Redemption of trust preferred-linked securities	**—**	(180)	—
Short-term borrowings, net	**(44)**	(267)	(282)
Capital lease obligations	**(9)**	(12)	(107)
Issuance of common stock	**44**	265	—
Repurchase of common stock	**(3)**	(9)	(438)
Dividends on common stock	**(346)**	(338)	(325)
Net cash from (used for) financing activities	**(1,039)**	(16)	1,679
Net Increase (Decrease) in Cash and Cash Equivalents	**(79)**	(135)	204
Cash and Cash Equivalents at Beginning of Period	**133**	268	64
Cash and Cash Equivalents at End of Period	**$ 54**	$ 133	$ 268

See Notes to Consolidated Financial Statements

Table of Contents

DTE Energy Company
Consolidated Statement of Changes in Shareholders' Equity and Comprehensive Income

(Dollars in Millions, Shares in Thousands)	Common Stock Shares	Common Stock Amount	Retained Earnings	Accumulated Other Comprehensive Loss	Total
Balance, December 31, 2000	$ 142,651	$ 1,912	$ 2,097	$ —	$ 4,009
Net income	—	—	332	—	332
Issuance of new shares	29,017	1,060	—	—	1,060
Dividends declared on common stock	—	—	(324)	—	(324)
Repurchase and retirement of common stock	(10,534)	(155)	(270)	—	(425)
Unearned stock compensation	—	(6)	—	—	(6)
Net change in unrealized losses on derivatives, net of tax	—	—	—	(69)	(69)
Net change in unrealized gain on investments, net of tax	—	—	—	1	1
Other	—	—	11	—	11
Balance, December 31, 2001	161,134	2,811	1,846	(68)	4,589
Net income	—	—	632	—	632
Issuance of new shares	6,426	270	—	—	270
Dividends declared on common stock	—	—	(341)	—	(341)
Repurchase and retirement of common stock	(98)	(1)	(2)	—	(3)
Pension obligations (Note 14)				(518)	(518)
Net change in unrealized losses on derivatives, net of tax	—	—	—	(33)	(33)
Other	—	(28)	(3)	—	(31)
Balance, December 31, 2002	167,462	3,052	2,132	(619)	4,565
Net income	**—**	**—**	**521**	**—**	**521**
Issuance of new shares	**1,225**	**57**	**—**	**—**	**57**
Dividends declared on common stock	**—**	**—**	**(348)**	**—**	**(348)**
Repurchase and retirement of common stock	**(80)**	**(1)**	**—**	**—**	**(1)**
Pension obligations (Note 14)	**—**	**—**	**—**	**420**	**420**
Net change in unrealized losses on derivatives, net of tax	**—**	**—**	**—**	**17**	**17**
Net change in unrealized gain on investments, net of tax	**—**	**—**	**—**	**52**	**52**
Other	**—**	**1**	**3**	**—**	**4**
Balance, December 31, 2003	**168,607**	**$ 3,109**	**$ 2,308**	**$ (130)**	**$ 5,287**

The following table displays comprehensive income (loss):

(in Millions)	2003	2002	2001
Net income	**$ 521**	$ 632	$ 332
Other comprehensive income (loss), net of tax:			
Net unrealized losses on derivatives:			
Gains or (losses) arising during the period, net of taxes of $(8), $32 and $29	**16**	(60)	(53)
Amounts reclassified to earnings, net of taxes of $-, $(15) and $(14)	**1**	27	26
Cumulative effect of a change in accounting, net of taxes of $-, $- and $24	**—**	—	(42)
	17	(33)	(69)
Net change in unrealized gain on investments, net of taxes of $(28), $- and $(1)	**52**	—	1
Pension obligations, net of taxes of $(226), $280 and $-	**420**	(518)	—

Comprehensive income	**$1,010**	$ 81	$264

See Notes to Consolidated Financial Statements

DTE Energy Company
Notes to Consolidated Financial Statements

NOTE 1 - SIGNIFICANT ACCOUNTING POLICIES

Corporate Structure

DTE Energy is an exempt holding company under the Public Utility Holding Company Act of 1935 and owns the following businesses:

- Detroit Edison Company (Detroit Edison), an electric utility engaged in the generation, purchase, distribution and sale of electric energy to 2.1 million customers in southeast Michigan;

- Michigan Consolidated Gas Company (MichCon), a natural gas utility engaged in the purchase, storage, transmission and distribution and sale of natural gas to 1.2 million customers throughout areas of Michigan; and

- Other non-regulated subsidiaries engaged in energy marketing and trading, energy services and various other electricity, coal and gas related businesses.

Detroit Edison and MichCon are regulated by the Michigan Public Service Commission (MPSC). The Federal Energy Regulatory Commission (FERC) regulates certain activities of Detroit Edison's business as well as various other aspects of businesses under DTE Energy. In addition, we are regulated by other federal and state regulatory agencies including the Nuclear Regulatory Commission and the Environmental Protection Agency, among others.

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

Principles of Consolidation

We consolidate all majority owned subsidiaries and investments in entities in which we have controlling influence. Non-majority owned investments are accounted for using the equity method when the company is able to influence the operating policies of the investee. Non-majority owned investments include investments in limited liability companies, partnerships or joint ventures. When we do not influence the operating policies of an investee, the cost method is used. We eliminate all intercompany balances and transactions.

For entities that are considered variable interest entities we apply the provisions of FASB Interpretation No. (FIN) 46-R, *"Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51."* For a detailed discussion of FIN 46-R see Note 2 – New Accounting Pronouncements.

Basis of Presentation

The accompanying consolidated financial statements are prepared using accounting principles generally accepted in the United States of America. These accounting principles require us to use estimates and assumptions that impact reported amounts of assets, liabilities, revenues and expenses, and the disclosure of contingent assets and liabilities. Actual results may differ from our estimates.

We reclassified certain prior year balances to match the current year's financial statement presentation.

Revenues

Revenues from the sale and delivery of electricity, and the sale, delivery and storage of natural gas are recognized as services are provided. Detroit Edison and MichCon record revenues for electric and gas provided but unbilled at the end of each month. Under agreement with the MPSC, Detroit Edison was not allowed to raise rates through 2003. Through December 2001, MichCon's rates included a component for cost of gas sold that was fixed at $2.95 per thousand cubic feet (Mcf). In 2002, MichCon reinstated the gas cost recovery (GCR) mechanism that recovers the prudent and reasonable cost of gas sold subject to annual proceedings before the MPSC.

Non-regulated revenues are recognized as services are provided and products are delivered.

Since 2002, the FASB has issued significant accounting guidance that governs energy trading revenue recognition and classification. See Note 2 - New Accounting Pronouncements for additional detail.

Comprehensive Income

We comply with SFAS No. 130, "*Reporting Comprehensive Income*," that established standards for reporting comprehensive income. SFAS No. 130 defines comprehensive income as the change in common shareholders' equity during a period from transactions and events from non-owner sources, including net income. As shown in the following table, amounts recorded to other comprehensive income include unrealized derivative gains and losses under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," unrealized gains and losses on available for sale securities under SFAS No. 115, "*Accounting for Certain Investments in Debt and Equity Securities*," and minimum pension liabilities as prescribed by SFAS No. 87, "*Employers' Accounting for Pensions,*" at December 31, 2003. The minimum pension liability was reclassified to a regulatory asset during 2003 (Note 4).

(in Millions)	Net Unrealized Losses on Derivatives	Net Unrealized Gains on Investments	Minimum Pension Liability Adjustment	Accumulated Other Comprehensive Income
Beginning balance	$ (102)	$ 1	$ (518)	$ (619)
Current-period change	17	52	420	489
Ending balance	$ (85)	$ 53	$ (98)	$ (130)

Inventories

We value fuel inventory and materials and supplies at average cost.

Gas inventory at MichCon is determined using the last-in, first-out (LIFO) method. At December 31, 2003, the replacement cost of gas remaining in storage exceeded the $117 million LIFO cost by $251 million. At December 31, 2002, the replacement cost exceeded the $55 million LIFO cost by $187 million. During 2001, MichCon liquidated 2.1 billion cubic feet (Bcf) of prior years' LIFO layers at an average cost of $0.39 per Mcf. MichCon's average gas purchase rate in 2001 was $2.83 per Mcf higher than the average LIFO liquidation rate. Applying LIFO cost in valuing the liquidation, as opposed to using the average purchase rate, decreased 2001 cost of gas by $5.8 million and increased earnings by $3.8 million, net of taxes.

Through December 2002, the Energy Marketing & Trading segment used the fair value method to price gas inventories. To comply with the accounting requirements resulting from the rescission of Emerging Issues Task Force (EITF) Issue No. 98-10, "*Accounting for Energy Trading Activities and Risk Management Activities*," the Energy Marketing & Trading segment changed to the average cost method for its gas inventories, effective January 2003.

Table of Contents

Property, Retirement and Maintenance, and Depreciation and Depletion

Summary of property by classification as of December 31:

(in Millions)	2003	2002
Property, Plant and Equipment		
Electric Utility		
Generation	**$ 6,938**	$ 6,515
Distribution	**5,733**	5,606
Transmission (1)	**—**	813
Total Electric Utility	**12,671**	12,934
Gas Utility		
Distribution	**1,961**	1,903
Storage	**224**	212
Other	**855**	906
Total Gas Utility	**3,040**	3,021
Energy Services		
Coal Based Fuels	**652**	636
On-Site Energy	**180**	172
Merchant Generation	**229**	228
Other	**13**	9
Total Energy Services	**1,074**	1,045
Other non-regulated and other	**894**	862
Total Property, Plant and Equipment	**17,679**	17,862
Less Accumulated Depreciation and Depletion		
Electric Utility		
Generation	**(3,231)**	(3,046)
Distribution	**(2,108)**	(2,051)
Transmission (1)	**—**	(327)
Total Electric Utility	**(5,339)**	(5,424)
Gas Utility		
Distribution	**(798)**	(756)
Storage	**(102)**	(99)
Other	**(432)**	(457)
Total Gas Utility	**(1,332)**	(1,312)
Energy Services		
Coal Based Fuels	**(219)**	(163)
On-Site Energy	**(42)**	(30)
Merchant Generation	**(20)**	(11)
Other	**(2)**	(1)
Total Energy Services	**(283)**	(205)
Other non-regulated and other	**(401)**	(379)
Total Accumulated Depreciation and Depletion	**(7,355)**	(7,320)
Net Property, Plant and Equipment	**$10,324**	$ 10,542

(1) Represents the operations of ITC that were sold in February 2003.

Property is stated at cost and includes construction-related labor, materials and overheads. The cost of properties retired, less salvage, at Detroit Edison and MichCon are charged to accumulated depreciation.

Expenditures for maintenance and repairs are charged to expense when incurred, except for Fermi 2. Approximately $37 million of expenses related to the anticipated Fermi 2 refueling outage scheduled for 2004 are being accrued on a pro-rata basis over an 18-month period that began in May 2003. We have utilized the accrue-in-advance policy for nuclear refueling outage costs since the Fermi 2 plant was placed in service in 1988. This method also matches the regulatory recovery of these costs in rates set by the MPSC.

We base depreciation provisions for utility property at Detroit Edison and MichCon on straight-line and units of production rates approved by the MPSC. The composite depreciation rate for Detroit Edison was 3.4 % in 2003, 2002 and 2001. The composite depreciation rate for MichCon was 3.5%, 3.6% and 3.9% in 2003, 2002 and 2001, respectively.

The average estimated useful life for each class of property, plant and equipment as of December 31, 2003 follows:

	Estimated Useful Lives in Years		
Utility	**Generation**	**Distribution**	**Transmission (1)**
Electric	39	37	—
Gas	N/A	26	28

(1) The electric transmission assets were sold in February 2003.

Non-regulated property is depreciated over its estimated useful life using straight-line, declining-balance or units-of-production methods.

We credit depreciation, depletion and amortization expense when we establish regulatory assets for stranded costs related to the electric Customer Choice program and deferred environmental expenditures.

Gas Production

We follow the successful efforts method of accounting for investments in gas properties. Under this method of accounting, all property acquisition costs and costs of exploratory and development wells are capitalized when incurred, pending determination of whether the well has found proved reserves. If an exploratory well has not found proved reserves, the costs of drilling the well are expensed. The costs of development wells are capitalized, whether productive or nonproductive. Geological and geophysical costs on exploratory prospects and the costs of carrying and retaining unproved properties are expensed as incurred. An impairment loss is recorded to the extent that capitalized costs of unproved properties, on a property-by-property basis, are considered not to be realizable. An impairment loss is recorded if the net capitalized costs of proved gas properties exceed the aggregate related undiscounted future net revenues. Depreciation, depletion and amortization of proved gas properties are determined using the units-of-production method.

Long-Lived Assets

Long-lived assets that we own are reviewed for impairment whenever events or changes in circumstances indicate the carrying amount of an asset may not be recoverable. If the carrying amount of the asset exceeds the expected future cash flows generated by the asset, an impairment loss is recognized resulting in the asset being written down to its estimated fair value. Assets to be disposed of are reported at the lower of the carrying amount or fair value less cost to sell.

Software Costs

We capitalize the costs associated with computer software we develop or obtain for use in our business. We amortize computer software costs on a straight-line basis over expected periods of benefit once the installed software is ready for its intended use.

Excise and Sales Taxes

We record the billing of excise and sales taxes as receivables with an offsetting payable to the applicable taxing authority, with no impact on the statement of operations.

Deferred Debt Costs

The costs related to the issuance of long-term debt are deferred and amortized over the life of each debt issue. In accordance with MPSC regulations applicable to our electric and gas utilities, the unamortized discount, premium and expense related to debt redeemed with a refinancing are amortized over the life of the replacement issue. Discount, premium and expense on early redemptions of debt associated with non-regulated operations are charged to earnings.

Insured and Uninsured Risks

We have a comprehensive insurance program in place to provide coverage for various types of risks. Our insurance policies cover risk of loss from various events, including catastrophic storms, general liability, workers' compensation, auto liability, property and directors and officers liability.

Under our risk management policy, we self-insure portions of certain risks up to specified limits, depending on the type of exposure. We periodically review our insurance coverages and during 2003, we reviewed our process for estimating and recognizing reserves for self-insured risks. As a result of this review, we revised the process for estimating liabilities under our self-insured layers to include an actuarially determined estimate of "incurred but not reported" (IBNR) claims. This revision resulted in the recording of an additional liability and reduced earnings in 2003 by approximately $15 million, primarily related to general liability and workers' compensation exposures. We intend to have an actuarially determined estimate of our IBNR liability prepared annually and will adjust the related reserve as appropriate.

Stock-Based Compensation

We have a stock-based employee compensation plan, which is described in Note 15. The plan permits the awarding of various stock awards, including options, restricted stock and performance shares. We account for stock awards under the plan under the recognition and measurement principles of Accounting Principles Board (APB) Opinion No. 25, " *Accounting for Stock Issued to Employees* ." No compensation cost related to stock options is reflected in net income, as all options granted had an exercise price equal to the market value of the underlying common stock on the date of grant. The recognition provisions under SFAS No. 123, " *Accounting for Stock-Based Compensation*," require the recording of compensation expense for stock options equal to their fair value at date of grant as determined using an option pricing model. The following table illustrates the effect on net income and earnings per share if we had recorded compensation expense for options granted under the fair value recognition provisions of SFAS No. 123.

Table of Contents

(in Millions, except per share amounts)	2003	2002	2001
Net Income As Reported	**$ 521**	$ 632	$ 332
Less: Total Stock-based Expense (1)	**(7)**	(7)	(9)
Pro Forma Net Income	**$ 514**	$ 625	$ 323
Earnings Per Share			
Basic – as reported	**$ 3.11**	$ 3.85	$ 2.17
Basic – pro forma	**$ 3.06**	$ 3.81	$ 2.11
Diluted – as reported	**$ 3.09**	$ 3.83	$ 2.16
Diluted – pro forma	**$ 3.05**	$ 3.79	$ 2.10

(1) Expense determined using a Black-Scholes based option pricing model.

Investments in Debt and Equity Securities

We generally classify investments in debt and equity securities as either trading or available-for-sale and have recorded such investments at market value with unrealized gains or losses included in the Consolidated Statement of Operations or in other comprehensive income or loss, respectively. Changes in the fair value of certain other investments are recorded as adjustments to regulatory assets or liabilities.

Gains from Sale of Interest in Synthetic Fuel Facilities

When we sell an interest in a synfuel facility, we recognize the gain from such sale under the installment method of accounting. Gain recognition is dependent on the synfuel production qualifying for Section 29 tax credits. Accordingly, we have deferred gains totaling $311 million and $161 million as of December 31, 2003 and 2002, respectively.

Investment in Plug Power

In 1997, we invested in Plug Power Inc., a company that designs and develops on-site electric fuel cell power generation systems. Since Plug Power is considered a development stage company, generally accepted accounting principles required us to record gains and losses from Plug Power stock issuances as an adjustment to equity. Prior to November 2003 we accounted for our investment in Plug Power Inc. under the equity method of accounting. We did not participate in Plug Power's secondary stock offering in November 2003 and as of December 31, 2003 we own approximately 19% of Plug Power's common stock. We have determined that we do not have the ability to exercise significant influence over the operating or financial policies of Plug Power. Accordingly, we began prospective application of the cost method of accounting for our investment in Plug Power, effective November 2003. We record our investment at market value and account for unrealized gains and losses in other comprehensive income or loss.

Consolidated Statement of Cash Flows

We consider investments purchased with a maturity of three months or less to be cash equivalents. Cash contractually designated for debt service is classified as restricted cash.

(in Millions)	2003	2002	2001
Changes in Assets and Liabilities, Exclusive of Changes Shown Separately			
Accounts receivable, net	**$ (113)**	$ (157)	$ 17
Accrued unbilled receivables	**(20)**	(54)	(19)
Accrued gas cost recovery revenue	**29**	(5)	(14)
Inventories	**(61)**	(71)	(76)
Accounts payable	**(21)**	66	(178)
Income taxes payable	**135**	(8)	(105)
General taxes	**(12)**	(36)	22
Risk management and trading activities	**127**	69	(80)
Pension contributions	**(222)**	(35)	(35)
Postretirement obligation	**93**	58	27
Other	**138**	4	(86)
	$ 73	$ (169)	$ (527)

Other cash and non-cash investing and financing activities for the years ended December 31 were as follows:

(in Millions)	2003	2002	2001
Supplementary Cash Flow Information			
Interest paid (excluding interest capitalized)	**$552**	$ 551	$ 409
Income taxes paid	**31**	167	45
Noncash Investing and Financing Activities			
Exchange of debt	**$100**	$ —	$ —
Notes received from sale of synfuel projects	**238**	217	—
Issuance of equity-linked securities	**—**	21	—
Issuance of common stock for acquisition of MCN Energy	**—**	—	1,060

See the following notes for other accounting policies impacting our financial statements.

NOTE 2 – NEW ACCOUNTING PRONOUNCEMENTS

Derivative Instruments and Hedging Activities

Effective January 1, 2001, we adopted SFAS No. 133, "*Accounting for Derivative Instruments and Hedging Activities,*" as amended. SFAS No. 133 establishes accounting and reporting standards for derivative instruments and for hedging activities. SFAS No. 133 required that as of the date of initial adoption, the difference between the fair value of derivative instruments and the previous carrying amount of those derivatives be reported in net income or other comprehensive income as the cumulative effect of a change in accounting principle. The cumulative effect of adopting SFAS No. 133 on January 1, 2001 was an increase in net income of $3 million and an increase in other comprehensive loss of $42 million.

Effective July 1, 2003, we adopted SFAS No. 149, "*Amendment of Statement 133 on Derivative Instruments and Hedging Activities.*" The statement amends and clarifies financial accounting and reporting for derivative instruments, including derivative instruments embedded in other contracts and for hedging activities. Our financial statements were not impacted by the adoption of SFAS No. 149.

In August 2003, the EITF released Issue No. 03-11, which provides guidance on whether to report realized gains or losses on a gross or net basis on physically settled derivative contracts not held for trading purposes. The new guidance was implemented in the fourth quarter of 2003 and had an immaterial effect on our financial statements.

See Note 12 – Financial and Other Derivative Instruments for additional information.

Energy Trading Contracts

Under EITF Issue No. 98-10, companies were required to use mark-to-market accounting for contracts utilized in energy trading activities. EITF Issue No. 98-10 was rescinded in October 2002, and energy trading contracts must now be reviewed to determine if they meet the definition of a derivative under SFAS No. 133. SFAS No. 133 requires all derivatives to be recognized in the statement of financial position as either assets or liabilities measured at their fair value and sets forth conditions in which a derivative instrument may be designated and recognized as a hedge. SFAS No. 133 also requires that changes in the fair value of derivatives be recognized in earnings unless specific hedge accounting criteria are met. Energy trading contracts not meeting the definition of a derivative are accounted for under settlement accounting, effective October 25, 2002 for new contracts and effective January 1, 2003 for existing contracts. Derivative contracts are only marked to market to the extent that markets are considered highly liquid where objective, transparent prices can be obtained. Unrealized gains and losses are fully reserved for transactions that do not meet this criteria.

Additionally, inventory utilized in energy trading activities accounted for under the fair value method of accounting as prescribed by Accounting Research Bulletin (ARB) No. 43 is no longer permitted. DTE Energy's Energy Marketing & Trading segment uses gas inventory in its trading operations and switched to the average cost inventory accounting method in January 2003.

Effective January 1, 2003, we applied EITF Issue 02-03 which rescinded EITF Issue 98-10. As a result of discontinuing the application of EITF Issue No. 98-10 to energy contracts and ARB No. 43 to gas inventory, we recorded a cumulative effect of accounting change that reduced net income for the first quarter of 2003 by $16 million (net of taxes of $9 million.)

Goodwill and Other Intangible Assets

Effective January 1, 2002, we adopted SFAS No. 142. "*Goodwill and Other Intangible Assets,*" which addresses the financial accounting and reporting standards for the acquisition of intangible assets outside of a business combination and for goodwill and other intangible assets subsequent to their acquisition. This accounting standard requires that goodwill be separately disclosed from other intangible assets in the balance sheet. Additionally under this statement, goodwill is no longer amortized, but must be reviewed at least annually for impairment. The provisions of this accounting standard also required the completion of a transitional impairment test within six months of adoption, with any impairment treated as a cumulative effect of a change in accounting principal. We completed the annual goodwill impairment test and have determined that no impairment exists.

In accordance with SFAS No. 142, we discontinued the amortization of goodwill effective January 1, 2002. A reconciliation of previously reported 2001 net income and earnings per share to the amounts adjusted for the exclusion of goodwill amortization follows:

	Year Ended December 31, 2001		
(In Millions, except per share amounts)	**Net Income**	**Basic Earnings Per Share**	**Diluted Earnings Per Share**
As reported	$ 332	$ 2.17	$ 2.16
Add: Goodwill amortization	31	.20	.20
As adjusted	$ 363	$ 2.37	$ 2.36

In connection with the adoption of SFAS No. 142, we also reassessed the useful lives and the classification of identifiable intangible assets and determined that they continue to be appropriate. Our intangible assets consist primarily of software and are subject to amortization. Intangible assets amortization expense was $40 million in 2003, $46 million in 2002 and $48 million in 2001. There were no material acquisitions of intangible assets during 2003 and 2002. The gross carrying amount and accumulated amortization of intangible assets at December 31, 2003 were $537 million and $303 million, respectively. The gross carrying amount and accumulated amortization of intangible assets at December 31, 2002 were $526 million and $317 million, respectively. Amortization expense of intangible assets is estimated to be $40 million annually for 2004 through 2008.

Asset Retirement Obligations

On January 1, 2003, we adopted SFAS No. 143, "*Accounting for Asset Retirement Obligations,*" which requires the fair value of an asset retirement obligation be recognized in the period in which it is incurred. It applies to legal obligations associated with the retirement of long-lived assets resulting from the acquisition, construction, development and (or) the normal operation of a long-lived asset. When a new liability is recorded, an entity will capitalize the costs of the liability by increasing the carrying amount of the related long-lived asset. The liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, an entity settles the obligation for its recorded amount or incurs a gain or loss upon settlement.

We have identified a legal retirement obligation for the decommissioning costs for our Fermi 1 and 2 nuclear plants. To a lesser extent, we have retirement obligations for our synthetic fuel operations, gas production facilities, asphalt plant, gas gathering facilities and various other operations. As to regulated operations, we believe that adoption of SFAS No. 143 results primarily in timing differences in the recognition of legal asset retirement costs that we are currently recovering in rates and are deferring such differences under SFAS No. 71, "*Accounting for the Effects of Certain Types of Regulation.*"

As a result of adopting SFAS No. 143 on January 1, 2003, we recorded a plant asset of $306 million with offsetting accumulated depreciation of $106 million, a retirement obligation liability of $815 million and reversed previously recognized obligations of $377 million, principally nuclear decommissioning liabilities. We also recorded a cumulative effect amount related to regulated operations as a regulatory asset of $221 million, and a cumulative effect charge against earnings of $11 million (net of tax of $6 million) for 2003.

If a reasonable estimate of fair value cannot be made in the period the asset retirement obligation is incurred, such as assets with an indeterminate life, the liability is to be recognized when a reasonable estimate of fair value can be made. Generally, distribution assets have an indeterminate life, retirement cash flows cannot be determined and there is a low probability of retirement, therefore no liability has been recorded for these assets.

The pro forma effect on earnings had SFAS No. 143 been adopted for all periods presented would decrease reported net income and basic and diluted earnings per share as follows:

Year	(in Millions) Net Income	Basic and Diluted Earnings per Share
2003	4.8	.03
2002	4.8	.03
2001	4.2	.03

The pro forma effect of the asset retirement obligation had SFAS No. 143 been adopted for all periods presented would increase reported liabilities by $815 million and $807 million as of December 31, 2002 and 2001, respectively.

A reconciliation of the asset retirement obligation for 2003 follows:

(in Millions)	
Asset retirement obligations at January 1, 2003	$815
Accretion	55
Liabilities settled	(4)
Asset retirement obligations at December 31, 2003	$866

SFAS No. 143 also requires the quantification of the estimated cost of removal obligations, arising from other than legal obligations, which have been accrued through depreciation charges. At December 31, 2002, we reclassified approximately $729 million of previously accrued asset removal costs related to our regulated operations, which had been previously netted against accumulated depreciation, to an asset removal cost liability. At December 31, 2003, we reclassified approximately $655 million of these accrued asset removal obligations to regulatory liabilities.

Exit and Disposal Activities

Effective January 1, 2003, we adopted SFAS No. 146, "*Accounting for Costs Associated with Exit or Disposal Activities* ," which requires that the liability for costs associated with exit or disposal activities be recognized when incurred, rather than at the date of a commitment to an exit or disposal plan. The adoption of this statement had no impact on our consolidated financial statements.

Consolidation of Variable Interest Entities

In January 2003, FASB Interpretation No. (FIN) 46, *"Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51,"* was issued and requires an investor with a majority of the variable interests (primary beneficiary) in a variable interest entity to consolidate the assets, liabilities and results of operations of the entity. A variable interest entity is an entity in which the equity investors do not have controlling interests, the equity investment at risk is insufficient to finance the entity's activities without receiving additional subordinated financial support from other parties, or equity investors do not share proportionally in gains or losses. FIN 46 was applicable (i) immediately for all variable interest entities created after January 31, 2003; or (ii) in the first fiscal year or interim period beginning after June 15, 2003 for variable interest entities created before February 1, 2003.

In October 2003, the FASB issued Staff Position No. FIN 46-6, which allowed for the deferral of the effective date for applying the provisions of Interpretation No. 46 for all interests in variable interest entities created before February 1, 2003, until the end of the first interim or annual period ending after December 15, 2003.

In December 2003, the FASB issued FIN 46-Revised (FIN 46-R) which clarified and replaced FIN 46. FIN 46-R again deferred the adoption of its provisions until periods ending after March 15, 2004, however, application is required for periods ended after December 15, 2003 for public entities that have interests in special-purpose entities. FIN 46-R defines special purpose entities as any entity whose activities are primarily related to securitizations or other forms of asset-backed financings or single-lessee leasing arrangements. In addition, FIN 46-R provides for further scope exceptions, including an exception for entities that are deemed to be a business, provided certain conditions are met.

As of December 31, 2003, we have determined that we have interests in various entities that would not qualify for the deferral provisions of FIN 46-R. As a result, we have adopted the provisions of FIN 46-R as of December 31, 2003 relative to our interests in these special purpose entities and have deferred the application of the provisions of FIN 46-R until March 31, 2004 for all other entities.

We have interests in two trusts formed for the sole purpose of issuing preferred securities and lending the gross proceeds to their respective parent companies. As of December 31, 2003, the trusts have $280 million of preferred securities outstanding. The sole assets of the trusts are debentures of their parent companies with terms similar to those of the related preferred securities.

Prior to the application of FIN 46-R, we consolidated these trusts. However, pursuant to the provisions of FIN 46-R, these trusts meet the definition of special purpose entities. Upon applying the provisions of FIN 46-R to these trusts as of December 31, 2003, we have determined that the trusts are variable interest entities, as our common equity investment is considered not at risk, and we are not the primary beneficiaries of the trusts. Accordingly, we have deconsolidated these trusts as of December 31, 2003 and our balance sheet was modified to reflect Investments in Unconsolidated Subsidiaries (included in Other Investments) of approximately $9 million, representing our common equity investment in the trusts, and Long-Term Debt of approximately $289 million, representing our obligations related to the trust debentures.

As permitted under FIN 46-R, we have deconsolidated the trusts in prior periods to be consistent with the current year's presentation. The adoption of FIN 46-R did not result in a cumulative effect of an accounting change adjustment.

We continue to evaluate all of our cost and equity method investments created prior to February 1, 2003 to determine whether those entities are variable interest entities that require consolidation. The effects of adopting the provisions of FIN 46-R to those entities are not expected to have a material effect on our financial statements.

Financial Instruments with Characteristics of Liabilities and Equity

Effective July 1, 2003, we adopted SFAS No. 150, *"Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity,"* which establishes standards for classifying and measuring as liabilities certain financial instruments that embody obligations of the issuer and have characteristics of both liabilities and equity.

The adoption of SFAS No. 150 did not impact our financial statements.

NOTE 3 – ACQUISITIONS AND DISPOSITIONS

Acquisition of MCN Energy

On May 31, 2001, DTE Energy completed the acquisition of MCN Energy by acquiring all of its outstanding shares of common stock for a combination of cash and shares of our common stock. See Note 8 – Common Stock and Earnings per Share for additional information. We purchased the outstanding common stock of MCN Energy for $2.3 billion and assumed existing MCN Energy debt and preferred securities of $1.5 billion.

We accounted for the acquisition using the purchase method and accordingly allocated the purchase price to the fair value of the assets acquired and liabilities assumed. The excess of the purchase price over the fair value of net assets acquired totaled $2.1 billion and was classified as goodwill. We began amortizing goodwill on June 1, 2001, on a straight-line basis using a 40-year life. In accordance with the adoption of SFAS No. 142 on January 1, 2002, the amortization of goodwill ceased, and goodwill is tested for impairment on an annual basis.

The following unaudited pro forma summary presents information about the company as if the acquisition became effective at the beginning of the respective periods. The pro forma amounts include the impact of certain adjustments, such as acquiring the operations of MCN Energy and issuing $1.35 billion of debt and 29 million shares of common stock to finance the acquisition. The pro forma amounts do not reflect the benefits from synergies we are receiving as a result of combining operations, do not reflect the actual results that would have occurred had the companies been combined for the periods presented, and are not necessarily indicative of future results of operations of the combined companies.

(in Millions, except per share amounts)	Pro Forma Year Ended December 31 2001
Operating revenues	$ 9,393
Income from continuing operations	$ 514
Net income	$ 537
Basic earnings per share:	
Income from continuing operations	$ 3.10
Total	$ 3.25
Diluted earnings per share:	
Income from continuing operations	$ 3.08
Total	$ 3.23

We incurred merger related costs of $27 million ($18 million, net of tax) and restructuring costs of $241 million ($157 million, net of tax) during 2001. Merger related charges represent systems integration, relocation, legal, accounting and consulting costs. Restructuring charges were primarily associated with a work force reduction plan. The plan included early retirement incentives and voluntary separation agreements for 1,186 employees, primarily in overlapping corporate support areas. Approximately $53 million of the merger and restructuring charges were paid as of December 31, 2001 and remaining benefit payments have been or will be paid from retirement plans.

Disposition of International Transmission Company – Discontinued Operation

In December 2002, we entered into a definitive agreement with affiliates of Kohlberg Kravis Roberts & Co. and Trimaran Capital Partners, LLC providing for the sale of ITC for approximately $610 million in cash. The sale closed in February 2003 following approval of the transaction by the FERC and the resolution of all other contingencies. The sale generated an after tax gain of $63 million, which was net of transaction costs and the portion of the gain that was refundable to customers.

The FERC had encouraged integrated electric utilities to transfer operating control of their transmission facilities to independent operators or sell the facilities to an independent company. DTE Energy's decision to sell ITC is consistent with our strategic view that maximization of shareholder value and high levels of customer service are best achieved with assets we own, operate and exercise significant control. As provided in FERC regulations, Detroit Edison continues to have fair and open access to Michigan's electric transmission network. The ITC electric transmission system continues to be operated by the Midwest Independent System Operator, a regional transmission operator. ITC received FERC approval to cap transmission rates charged to Detroit Edison's customers at current levels until December 31, 2004. Thereafter, rates are subject to adjustment by the FERC.

SFAS No. 144, "*Accounting for the Impairment or Disposal of Long-Lived Assets,*" provides that the results of operations of a component of an entity that has been disposed of should be reported as a discontinued operation when the operations and cash flows of the component have been eliminated from the ongoing operations of the entity and the entity will not have any significant continuing involvement in the operations of the component after the disposal transaction. As a result, we have reported the operations of ITC as a discontinued operation as shown in the following table:

(in Millions)	2003(3)	2002	2001(4)
Revenues (1)	**$21**	$138	$64
Expenses (2)	**13**	67	35
Operating income	**8**	71	29
Income taxes	**3**	25	9
Income from discontinued operations	**$ 5**	$ 46	$20

(1) Includes intercompany revenues of $18 million for 2003, $118 million for 2002 and $60 million for 2001.

(2) Excludes general corporate overhead costs that were previously allocated to ITC.

(3) Represents activity from January 1, 2003 through February 28, 2003 when ITC was sold.

(4) Represents activity from June 1, 2001 through December 31, 2001.

Prior to May 31, 2001, Detroit Edison owned and operated the transmission assets of ITC, which were vertically integrated with its other operations. Accordingly, revenues, expenses and cash flows associated with these transmission assets were included with the Energy Distribution – Regulated Power Distribution segment and were not separately identifiable. Effective June 1, 2001, the transmission assets of ITC were transferred to DTE Corporate and its revenues, expenses and cash flows were separately monitored to measure its financial and operating performance. Accordingly, the presentation of discontinued operations in the consolidated statement of operations reflects the results of ITC after May 31, 2001.

ITC had net property of $388 million at December 31, 2002. In conjunction with the sale of ITC, approximately $44 million of goodwill allocated to this segment was written off and reduced the net of tax gain.

Disposition of Detroit Edison's Steam Heating Business

In January 2003, we sold Detroit Edison's steam heating business to Thermal Ventures II, LLP. This disposition is consistent with DTE Energy's strategy of divestiture of non-strategic assets. Due to the continuing involvement of Detroit Edison in the steam heating business, including the commitment to purchase $150 million in steam for resale through 2008, fund certain capital improvements and guarantee the buyer's credit facility, we recorded a net of tax loss of approximately $14 million in 2003. As a result of Detroit Edison's continuing involvement, this transaction is not considered a sale for accounting purposes. The steam heating business had assets of $6 million at December 31, 2002, and had net losses of $12 million in 2002 and net income of $3 million in 2001. See Note 13 – Commitments and Contingencies.

NOTE 4 - REGULATORY MATTERS

Regulation

Detroit Edison and MichCon are subject to the regulatory jurisdiction of the MPSC, which issues orders pertaining to retail rates, recovery of certain costs, including the costs of generating facilities and regulatory assets, conditions of service, accounting and operating-related matters. Detroit Edison is also regulated by the FERC with respect to financing authorization and wholesale electric activities.

In 1998, based on MPSC Orders, the Power Generation business of Detroit Edison started transitioning to market-based rates with the start of a customer choice program. In compliance with EITF Issue No. 97-4, " *Deregulation of the Pricing of Electricity*", we ceased application of SFAS No. 71, "*Accounting for the Effects of Certain Types of Regulation*", for the generation business in 1998. Since that time, there have been significant legislative and regulatory changes in Michigan that have resulted in our generation business being fully regulated with cost-based ratemaking.

In June 2000, the Customer Choice and Electric Reliability Act (PA 141) was enacted into law providing the regulatory framework to maintain cost-based rates for retail customers and ensuring the recovery of all amounts of generation-related stranded costs from choice customers. Subsequent MPSC orders developed a cost-based methodology to determine the amount of our net stranded costs to be recovered from choice customers. Since the rates for retail customers and the recovery of net stranded costs that are set by the regulator recover Detroit Edison's generation costs and are billed and recovered from full service and choice customers, the criteria of SFAS No. 71 are satisfied. In addition, we believe we have both the legislative and regulatory authority to defer regulatory costs and to begin recovery of such costs starting in 2004 after the PA 141 mandated rate freeze expires. The SEC had no objection to Detroit Edison resuming application of SFAS No. 71 for its generation business in the fourth quarter of 2002. Detroit Edison recorded $15 million of additional regulatory assets for the equity component of Allowance for Funds Used During Construction and costs related to reacquired debt that was refinanced with lower cost debt. Prior period financial statements were not restated due to the immaterial effect of retroactively applying SFAS No. 71 to Detroit Edison's generation business.

Regulatory Assets and Liabilities

SFAS No. 71 requires the recording of regulatory assets and liabilities for certain transactions that would have been treated as revenue and expense in non-regulated businesses. Continued applicability of SFAS No. 71 requires that rates be designed to recover specific costs of providing regulated services and be charged to and collected from customers. Future regulatory changes or changes in the competitive environment could result in the company discontinuing the application of SFAS No. 71 for some or all of its businesses and require the write-off of the portion of any regulatory asset or liability that was no longer probable of recovery through regulated rates. Management believes that currently available facts support the continued application of SFAS No. 71 to Detroit Edison and MichCon.

The following are the balances of the regulatory assets and liabilities at December 31:

(in Millions)	2003	2002
Assets		
Securitized regulatory assets	**$1,527**	$1,613
Recoverable income taxes related to securitized regulatory assets	**$ 837**	$ 884
Recoverable minimum pension liability	**585**	—
Asset retirement obligation	**192**	—
Other recoverable income taxes	**114**	118
Recoverable costs under PA 141		
Net stranded costs	**68**	10
Deferred Clean Air Act expenditures	**54**	11
Midwest Independent System Operator charges	**21**	9
Transmission integration costs	**10**	19
Electric Choice implementation costs	**84**	76
Enhanced security costs	**6**	—
Unamortized loss on reacquired debt	**60**	36
Deferred environmental costs	**29**	29
Accrued gas cost recovery	**19**	22
Other	**3**	5
	2,082	1,219
Less amount included in current assets	**(19)**	(22)
	$ 2,063	$1,197
Liabilities		
Asset removal costs	**$ 655**	$ —
Excess securitization savings	**14**	35
Customer Refund – 1997 Storm	**2**	2
Refundable income taxes	**146**	142
Accrued GCR potential disallowance	**26**	—
Other	**3**	3
	846	182
Less amount included in current and other liabilities	**(29)**	(3)
	$ 817	$ 179

Securitized regulatory assets — The net book balance of the Fermi 2 nuclear plant was written off in 1998 and an equivalent regulatory asset was established. In 2001, the Fermi 2 regulatory asset and certain other regulatory assets were securitized pursuant to Public Act (PA) 142 and an MPSC Order. A non-bypassable securitization bond surcharge recovers the securitized regulatory asset over a fourteen-year period ending in 2015.

Recoverable income taxes related to securitized regulatory assets — Receivable for the recovery of income taxes to be paid on the non-bypassable securitization bond surcharge. A non-bypassable securitization tax surcharge recovers the income tax.

Recoverable minimum pension liability — An additional minimum pension liability was recorded in 2002 and 2003 (Note 14). The traditional rate setting process allows for the recovery of pension costs as measured by generally accepted accounting principles. Accordingly, the minimum pension liability associated with regulated operations is recoverable.

Asset retirement obligation — Asset retirement obligations were recorded pursuant to adoption of SFAS No. 143 in 2003. These obligations are primarily for Fermi 2 decommissioning costs that are recovered in rates.

Other recoverable income taxes — Income taxes receivable from Detroit Edison's customers representing the difference in property-related deferred income taxes payable and amounts previously reflected in Detroit Edison's rates.

Net stranded costs — PA 141 permits, after MPSC authorization, the full recovery of fixed cost deficiency associated with the electric Customer Choice program. Net stranded costs occur when fixed cost related revenues do not cover the fixed cost revenue requirements.

Deferred Clean Air Act expenditures — PA 141 permits, after MPSC authorization, the recovery of and a return on Clean Air Act expenditures.

Midwest Independent System Operator charges — PA 141 permits, after MPSC authorization, the recovery of charges from a regional transmission operator such as the Midwest Independent System Operator.

Transmission integration costs — PA 141 permits, after MPSC authorization, the recovery of transmission integration costs.

Electric Choice implementation costs — PA 141 permits, after MPSC authorization, the recoverability of costs incurred associated with the implementation of the electric Customer Choice program. A deferred return of 7% is also being accrued on the unrecovered balance.

Enhanced security costs — PA 141 permits, after MPSC authorization, the recovery of enhanced homeland security costs for an electric generating facility.

Unamortized loss on reacquired debt — The unamortized discount, premium and expense related to debt redeemed with a refinancing are deferred, amortized and recovered over the life of the replacement issue.

Deferred environmental costs — The MPSC approved recovery of costs for investigation and remediation incurred at former manufactured gas plant sites.

Accrued gas cost recovery — The amount of under-recovered gas costs incurred by MichCon recoverable through the GCR mechanism. A deferred return computed using MichCon's short-term borrowing rate is also being accrued on the under-recovered balance.

Asset removal costs – The amount collected from customers for the funding of future asset removal activities.

Excess securitization savings — Savings associated with the 2001 securitization of Fermi 2 and other costs are refundable to Detroit Edison's customers.

Customer Refund – 1997 Storm — The over collection of the 1997 storm costs, which are refundable to Detroit Edison customers after January 1, 2004.

Refundable income taxes — Income taxes refundable to MichCon's customers representing the difference in property-related deferred income taxes payable and amounts recognized pursuant to MPSC authorization.

Accrued GCR potential disallowance — A March 2003 MPSC Order in MichCon's 2002 GCR plan case required MichCon to reduce revenues in the calculation of its 2002 GCR expense.

Electric Transitional Rate Plan

Rate Request — In June 2003, Detroit Edison filed an application with the MPSC requesting a change in retail electric rates, resumption of the Power Supply Cost Recovery (PSCR) mechanism, and recovery of net stranded costs. The application requested a base rate increase for both full service and electric Customer Choice customers totaling $416 million annually (approximately 12% increase) in 2006, with a three year phase-in starting in 2004 as the caps on customer rates expire, as subsequently discussed. Detroit Edison proposed that the $416 million increase be allocated between full service customers ($265 million) and electric Customer Choice customers ($151 million). In November 2003, Detroit Edison increased its original rate request by $11 million to $427 million. The rate request also seeks a five-year surcharge totaling $109 million from both full service and electric Customer Choice customers to recover certain deferred regulatory asset balances, including electric Customer Choice program implementation costs, return on and of clean air investments made prior to inclusion in base rates and net stranded costs for years prior to 2004. Detroit Edison requested authority to increase rates on an interim basis by $299 million annually to all customers not subject to a rate cap. PA 141 became effective in June 2000 and contains provisions freezing rates through 2003 and preventing rate increases for residential customers through 2005 and for small commercial and industrial customers through 2004. Detroit Edison requested the MPSC act on our interim request in order to be effective January 1, 2004. Concurrent with the issuance of an order for interim rate relief, Detroit Edison requested reinstatement of the PSCR mechanism. The PSCR mechanism allows Detroit Edison to recover through rates its fuel and purchased power expenses. The PSCR was suspended by the MPSC following passage of PA 141. Detroit Edison also proposed that base rates for the customer classes still subject to rate caps in 2004 and 2005 remain frozen and not be subject to the PSCR mechanism until the caps expire.

A summary of the total rate increase request follows:

(in Millions)	
Base Rate Revenue Deficiency	$ 553
PSCR Savings/Choice Mitigation	(126)
Base Rate Increase	427
Regulatory Asset Recovery Surcharge	109
Total	$ 536
Phase in By Year	
2004	$ 299
2005	57
2006	180
Total	$ 536

The filing also requests a permanent capital structure based on 50% debt and 50% equity, and a proposed return on equity (ROE) of 11.5%. Detroit Edison is also proposing a symmetrical ROE sharing mechanism, which will apply to full service and electric Customer Choice customers whose rates are no longer capped under PA 141. The sharing proposal would provide that shareholders retain all earnings within a 1% band above and below the authorized ROE. If the actual ROE falls outside of the band, customers would share between 20% and 80% of the excess or shortfall of earnings, depending on actual ROE. The ROE sharing mechanism would be effective for the calendar year in which a final order is received in this case.

As previously discussed, Detroit Edison requested that its PSCR clause remain suspended and that implementation of a new PSCR factor not begin until the date of the MPSC order authorizing adequate and compensatory relief. Detroit Edison also proposed an adjustment whereby the revenues from the sale of excess capacity and off-system energy would be used to mitigate the effect of stranded costs. In December 2003, the MPSC issued an order that reinstated the PSCR clause on January 1, 2004 and did not rule on the mitigation adjustment proposed by Detroit Edison. Detroit Edison has filed an appeal of this order with the Michigan Court of Appeals.

MPSC Interim Rate Order — On February 20, 2004, the MPSC issued an order for interim rate relief. The order authorized an interim increase in base rates, a transition charge for customers participating in the electric Customer Choice program and a new PSCR factor.

The interim base rate increase totaled $248 million annually, effective February 21, 2004, and is applicable to all customers not subject to the rate cap. The increase will be allocated to both full service customers ($240 million) and electric Customer Choice customers ($8 million). However, because of the rate caps under PA 141, not all of the increase will be recognized in 2004. Additionally, the MPSC terminated certain transition credits and authorized a uniform 4 mills per kWh transition charge to Choice customers which is designed to result in $30 million in revenues, based on an estimated 7,565 gWh level of Choice sales volumes. The MPSC concluded that the implementation of transition charges, coupled with the termination of transition credits, will reduce the anticipated volume of Choice sales resulting in an additional $30 million in margins. The MPSC also authorized a PSCR factor for all customers, a credit of 1.05 mills per kWh compared to the 2.04 mills per kWh charge previously in effect. However, the MPSC order will allow Detroit Edison to increase base rates for customers still subject to the cap in an equal and offsetting amount with the change in the PSCR factor to maintain the total capped rate levels currently in effect for these customers.

Although the base rate increase totaled $248 million, the interim order is only designed to result in an increase in 2004 revenues of $71 million. This lower amount is a result of the rate caps, the February 21, 2004 effective date and the PSCR adjustment. Amounts collected will be subject to refund pending a final order in this rate case.

As part of the interim order, the MPSC approved Detroit Edison’s request to recover pension and healthcare expenses included in the rate filing. The recovery is conditioned on Detroit Edison making minimum annual prorated pension contributions equal to the amount of expense reflected in rates during the period that the authorized interim rates are in effect. Detroit Edison has agreed to comply with this requirement through the interim period until a final order is issued in this case. Additionally, the MPSC interim order requires Detroit Edison to continue funding the Low Income Energy Efficiency Fund at $40 million annually.

The MPSC deferred addressing other items in the rate request, including a surcharge to recover regulatory assets, until a final rate order is issued which is expected in the third quarter of 2004. We cannot predict the amount of final rate relief that will be granted by the MPSC.

Electric Industry Restructuring

Electric Rates, Customer Choice and Stranded Costs — PA 141 provided Detroit Edison with the right to recover net stranded costs, codified and established January 1, 2002 as the date for full implementation of the MPSC’s existing electric Customer Choice program, and required the MPSC to reduce residential electric rates by 5%. At that time, PA 142 also became effective. PA 142 provided for the recovery through securitization of “qualified costs” which consist of an electric utility’s regulatory assets, plus various costs associated with, or resulting from, the establishment of a competitive electric market and the issuance of securitization bonds.

Acting pursuant to PA 141, in an order issued in June 2000, the MPSC reduced Detroit Edison’s residential electric rates by 5% and imposed a rate freeze for all classes of customers through 2003. In April 2001, commercial and industrial rates were lowered by 5% as a result of savings derived from the issuance of securitization bonds in March 2001, as subsequently discussed.

Certain costs may be deferred and recovered once rates can be increased. This rate cap may be lifted when certain market test provisions are met, specifically, when an electric utility has no more than 30% of generation capacity in its relevant market, with consideration for capacity needed to meet a utility's responsibility to serve its retail customers. Statewide, multi-utility transmission system improvements also are required. In May 2003, Detroit Edison submitted filings with the MPSC regarding its compliance with the provisions of PA 141 related to market test and transmission system improvements. Detroit Edison entered into a settlement agreement with interested parties, indicating that the market power test provisions of PA 141 had been met. The MPSC approved the settlement agreement on February 20, 2004.

As required by PA 141, the MPSC conducted a proceeding to develop a methodology for calculating the net stranded costs associated with electric Customer Choice. In a December 2001 order, the MPSC determined that Detroit Edison could recover net stranded costs associated with the fixed cost component of its electric generation operations. Specifically, there would be an annual proceeding or true-up before the MPSC reconciling the receipt of revenues associated with the fixed cost component of its generation services to the revenue requirement for the fixed cost component of those services, inclusive of an allowance for the cost of capital. Any resulting shortfall in recovery, net of mitigation, would be considered a net stranded cost. The MPSC, in its December 2001 order, also determined that Detroit Edison had no net stranded costs in 2000 and consequently established a zero net stranded cost transition charge for billing purposes in 2002. The MPSC authorized Detroit Edison to establish a regulatory asset to defer recovery of its incurred stranded costs, subject to review in a subsequent annual net stranded cost proceeding. The MPSC also determined that Detroit Edison should provide a full and offsetting credit for the securitization and tax charges applied to electric Customer Choice bills in 2002. In addition, the MPSC ordered an additional credit on bills equal to the 5% rate reduction realized by full service customers. Both credits were to be funded from savings derived from securitization. The December 2001 order, coupled with lower wholesale power prices, has encouraged additional customer participation in the electric Customer Choice program and has resulted in the loss of margins attributable to generation services. In May 2002, the MPSC denied Detroit Edison's request for rehearing and clarification of the December 2001 order. In June 2002, Detroit Edison filed an appeal of the MPSC order at the Michigan Court of Appeals, challenging the legality of specific aspects of the MPSC order. The Court of Appeals denied Detroit Edison's appeal.

In May 2002, Detroit Edison submitted its 2001 net stranded cost filing with the MPSC. The filing provided refinements to the MPSC Staff's calculation of net stranded costs that was adopted in the December 2001 order, sought more timely recovery of net stranded costs, and addressed issues raised by the continuation of securitization offsets and rate reduction equalization credits. The filing supported that Detroit Edison had no net stranded costs in 2000 and $13 million of recoverable net stranded costs attributable to electric Customer Choice in 2001. In the fourth quarter of 2002, Detroit Edison recorded an estimated regulatory asset of $10 million for the 2001 net stranded costs based on the MPSC Staff's report. In July 2003, the MPSC issued an order finding that Detroit Edison had no net stranded costs in 2000 and 2001 and established a zero net stranded cost transition charge for billing purposes in 2003. In addition, this order clarified the inclusion of revenue discounts granted customers under special contracts in the net stranded cost calculation, but declined to rule on the proposed modifications to the method for determining net stranded costs. Detroit Edison filed a petition for rehearing of the July 2003 order, which the MPSC denied in December 2003. Detroit Edison has appealed. During each quarter of 2003, Detroit Edison recorded a regulatory asset representing an estimate of the cumulative stranded costs as of that period. As a result of the MPSC July 2003 order and the related clarifying language, we recalculated net stranded costs for 2002 and 2003. Our revised and ongoing calculations conclude that the $68 million of net stranded costs recorded as of December 31, 2003 is appropriate.

Securitization — In an order issued in November 2000 and clarified in January 2001, the MPSC approved the issuance of securitization bonds to recover qualified costs that include the unamortized investment in Fermi 2, costs of certain other regulatory assets, Electric Choice implementation costs, costs of issuing securitization bonds, and the costs of retiring securities with the proceeds of securitization. The order permits the collection of these qualifying costs from Detroit Edison's customers.

Detroit Edison formed The Detroit Edison Securitization Funding LLC (Securitization LLC), a wholly owned subsidiary, for the purpose of securitizing its qualified costs. In March 2001, the Securitization LLC issued $1.75 billion of Securitization Bonds, and Detroit Edison sold $1.75 billion of qualified costs to the Securitization LLC. The Securitization Bonds mature over a 14-year period and have an annual average interest rate of 6.3% over the life of the bonds. Detroit Edison used the proceeds to retire debt and equity in approximately equal amounts. DTE Energy corporate likewise retired approximately 50% debt and 50% equity with the proceeds received as the sole shareholder of Detroit Edison. Detroit Edison implemented a non-bypassable surcharge on its customer bills, effective in March 2001, for the purpose of collecting amounts sufficient to provide for the payment of interest and principal and the payment of income tax on the additional revenue from the surcharge. As a result of securitization, Detroit Edison established a regulatory asset for securitized costs including costs that had previously been recorded in other regulatory asset accounts.

The Securitization LLC is independent of Detroit Edison, as is its ownership of the qualified costs. Due to principles of consolidation, qualified costs sold by Detroit Edison to the Securitization LLC and the securitization bonds appear on the company's consolidated statement of financial position. The company makes no claim to these assets. Ownership of such assets has vested in the Securitization LLC and been assigned to the trustee for the Securitization Bonds. Funds collected by Detroit Edison, acting in the capacity of a servicer for the Securitization LLC, are remitted to the trustee for the Securitization Bonds. Neither the qualified costs which were sold nor funds collected from Detroit Edison's customers for the payment of costs related to the Securitization LLC and Securitization Bonds are available to Detroit Edison's creditors.

Low-Income Energy Assistance Credit - In October 2003, Detroit Edison filed an application with the MPSC to implement a low-income energy assistance credit for residential electric customers. The proposed 2.6 cent per kilowatthour credit is expected to assist many low-income customers who are experiencing difficulties in paying their electric bills due to poor economic conditions in Detroit Edison's service area. Detroit Edison proposed to fund the low-income energy assistance credit by utilizing excess securitization savings currently being used to provide credits to electric Choice Customers. In January 2004, the MPSC issued an order implementing a 1 cent per kilowatthour low-income energy assistance credit for residential electric customers and terminated the rate equalization credit for uncapped electric Customer Choice customers.

Excess Securitization Savings — In January 2004, the MPSC issued an order directing Detroit Edison to file a report by March 15, 2004, of the accounting of the savings due to securitization and the application of those savings through December 2003. In addition, Detroit Edison was requested to include in the report an estimate of the foregone carrying cost associated with the excess securitization savings.

Blackout Costs

On August 14, 2003, failures in the regional power transmission grid caused nine of Detroit Edison's power plants to trip offline, which left virtually all of its 2.1 million customers without power. We estimate that amounts expensed in 2003 related to the blackout, excluding lost margins, were approximately $25 million ($16 million net of tax). In October 2003, Detroit Edison filed an accounting application with the MPSC requesting authority to defer outage related costs associated with the blackout until a future rate proceeding to recover outage costs from customers in a manner consistent with the provisions of PA 141. We anticipate an accounting order in the third quarter of 2004.

Gas Rate Plan

In September 2003, MichCon filed an application with the MPSC for an increase in service and distribution charges (base rates) for its gas sales and transportation customers. The filing requests an overall increase in base rates of $194 million per year (approximately 7% increase, inclusive of gas costs), beginning January 1, 2005. MichCon has requested that the MPSC increase base rates by $154 million per year on an interim basis by April 1, 2004. The interim request is based on a projected revenue deficiency for the test year 2004. Based on the procedural calendar established in this case, MichCon expects an interim order in the third quarter of 2004 and a final order relating to the $194 million base rate increase in the first quarter of 2005.

Primary factors that necessitate MichCon's request for increased base rates include significant increases in routine and mandated infrastructure improvements, increased operation and maintenance expenses, including employee pension and health care costs, and a decline in customer consumption. The filing also requests a permanent capital structure based on 50% debt and 50% equity, and a proposed ROE of 11.5%. MichCon is also proposing a symmetrical ROE sharing mechanism which would provide that shareholders retain all earnings within a 1% band above and below the authorized ROE. If the actual ROE falls outside of the band, customers would share between 20% and 80% of the excess or shortfall of earnings, depending on actual ROE.

In September 2003, MichCon also filed an application with the MPSC for the approval of depreciation rates, which will result in a modest increase in its composite depreciation rate. The Company anticipates that any depreciation change will be implemented contemporaneously with a MPSC order in MichCon's base rate case.

Gas Industry Restructuring

In December 2001, the MPSC approved MichCon's application for a voluntary, expanded permanent gas Customer Choice program, which replaced the experimental program that expired in March 2002. Effective April 2002, up to 40% of MichCon's customers could elect to purchase gas from suppliers other than MichCon. Effective April 2003, up to 60% of customers were eligible and by April 2004, all of MichCon's 1.2 million customers may participate in the program. The MPSC also approved the use of deferred accounting for the recovery of implementation costs of the gas Customer Choice program. As of December 2003, approximately 129,000 customers are participating in the gas Customer Choice program.

Gas Cost Recovery Proceedings

2002 Plan Year - In December 2001, the MPSC issued an order that permitted MichCon to implement GCR factors up to $3.62 per Mcf for January 2002 billings and up to $4.38 per Mcf for the remainder of 2002. The order also allowed MichCon to recognize a regulatory asset of approximately $14 million representing the difference between the $4.38 factor and the $3.62 factor for volumes that were unbilled at December 31, 2001. The regulatory asset is subject to the 2002 GCR reconciliation process. In March 2003, the MPSC issued an order in MichCon's 2002 GCR plan case. The MPSC ordered MichCon to reduce its gas cost recovery expenses by $26.5 million for purposes of calculating the 2002 GCR factor due to MichCon's decision to utilize storage gas during 2001 that resulted in a gas inventory decrement for the 2001 calendar year.

Although we recorded a $26.5 million reserve in the first quarter of 2003 to reflect the impact of this order, a final determination of actual 2002 revenue and expenses including any disallowances or adjustment will be decided in MichCon's 2002 GCR reconciliation case which was filed with the MPSC in February 2003. Intervening parties in this proceeding are seeking to have the MPSC disallow an additional $26 million, representing unbilled revenues at December 2001. One party has proposed that half of the $8 million related to the settlement of the Enron bankruptcy also be disallowed. The other two parties to the case have recommended that the Enron bankruptcy settlement be addressed in the 2003 GCR reconciliation case. A final order in this proceeding is expected in 2004. In addition, we filed an appeal of the March 2003 MPSC order with the Michigan Court of Appeals.

2003 Plan Year - In July 2003, the MPSC approved an increase in MichCon's 2003 GCR rate to a maximum of $5.75 per Mcf for the billing months of August 2003 through December 2003. As of December 31, 2003, MichCon has accrued a $19 million regulatory asset representing the under-recovery of actual gas costs incurred.

2004 Plan Year - In September 2003, MichCon filed its 2004 GCR plan case proposing a maximum GCR factor of $5.36 per Mcf. MichCon agreed to switch from a calendar year to an operational year as a condition of its settlement in the 2003 GCR Plan Case. The operational GCR year would run from April to March of the following year. To accomplish the switch, the 2004 GCR Plan Case reflects a 15-month transitional period, January 2004 through March 2005. Under the transition proposal, MichCon would file two reconciliations pertaining to the transition period; one addressing the January 2004 to March 2004 period, the other addressing the remaining April 2004 to March 2005 period. The plan also proposes a quarterly GCR ceiling price adjustment mechanism. This mechanism allows MichCon to increase the maximum GCR factor to compensate for increases in market prices thereby minimizing the possibility of a GCR under recovery.

Minimum Pension Liability

In December 2002, we recorded an additional minimum pension liability as required under SFAS No. 87, "*Employers' Accounting for Pensions,*" with offsetting amounts to an intangible asset and other comprehensive income. During the first quarter of 2003, the MPSC Staff provided an opinion that the MPSC's traditional rate setting process allowed for the recovery of pension costs as measured by SFAS No. 87. Based on the MPSC Staff opinion, management believes that it will be allowed to recover in rates the minimum pension liability associated with its regulated operations. In 2003, we reclassified approximately $585 million ($380 million net of tax) of other comprehensive loss associated with the minimum pension liability to a regulatory asset.

Other

In accordance with a November 1997 MPSC order, Detroit Edison reduced rates by $53 million annually to reflect the scheduled reduction in the revenue requirement for Fermi 2. The $53 million reduction was effective in January 1999. In addition, the November 1997 MPSC order authorized the deferral of $30 million of storm damage costs and amortization and recovery of the costs over a 24-month period commencing January 1998. After various legal appeals, the Michigan Court of Appeals remanded back to the MPSC for hearing the November 1997 order. In December 2000, the MPSC issued an order reopening the case for hearing. The parties in the case have agreed to a stipulation of fact and waiver of hearing. In June 2002, the MPSC issued an order modifying its 1997 order that will require Detroit Edison to refund approximately $1.5 million after January 1, 2004. In July 2002, the Michigan Attorney General filed an appeal with the Michigan Court of Appeals regarding the June 2002 MPSC Order.

We are unable to predict the outcome of the regulatory matters discussed herein. Resolution of these matters is dependent upon future MPSC orders, which may materially impact the financial position, results of operations and cash flows of the company.

NOTE 5 — NUCLEAR OPERATIONS

General

Fermi 2, our nuclear generating plant, began commercial operation in 1988. Fermi 2 has a design electrical rating (net) of 1,150 megawatts. This plant represents approximately 10% of Detroit Edison's summer net rated capability. The net book balance of the Fermi 2 plant was written off at December 31, 1998, and an equivalent regulatory asset was established. In 2001, the Fermi 2 regulatory asset was securitized. See Note 4 - Regulatory Matters. Detroit Edison also owns Fermi 1, a nuclear plant that was shut down in 1972 and is currently being decommissioned. The Nuclear Regulatory Commission (NRC) has jurisdiction over the licensing and operation of Fermi 2 and the decommissioning of Fermi 1.

Property Insurance

Detroit Edison maintains several different types of property insurance policies specifically for the Fermi 2 plant. These policies cover such items as replacement power and property damage. The Nuclear Electric Insurance Limited (NEIL) is the primary supplier of these insurance polices.

Detroit Edison maintains a policy for extra expenses, including replacement power costs necessitated by Fermi 2's unavailability due to an insured event. These policies have a 12-week waiting period and provide an aggregate $490 million of coverage over a three-year period.

Detroit Edison has $500 million in primary coverage and $2.25 billion of excess coverage for stabilization, decontamination, debris removal, repair and/or replacement of property and decommissioning. The combined coverage limit for total property damage is $2.75 billion.

For multiple terrorism losses caused by acts of terrorism not covered under the Terrorism Risk Insurance Act (TRIA) of 2002 occurring within one year after the first loss from terrorism, the NEIL policies would make available to all insured entities up to $3.2 billion plus any amounts recovered from reinsurance, government indemnity, or other sources to cover losses.

Under the NEIL policies, Detroit Edison could be liable for maximum assessments of up to approximately $28 million per event if the loss associated with any one event at any nuclear plant in the United States should exceed the accumulated funds available to NEIL.

Public Liability Insurance

As required by federal law, Detroit Edison maintains $300 million of public liability insurance for a nuclear incident. For liabilities arising from a terrorist act outside the scope of TRIA the policy is subject to one industry aggregate limit of $300 million. Further, under the Price-Anderson Amendments Act of 1988 (Act), deferred premium charges up to $101 million could be levied against each licensed nuclear facility, but not more than $10 million per year per facility. Thus, deferred premium charges could be levied against all owners of licensed nuclear facilities in the event of a nuclear incident at any of these facilities. The Act expired on August 1, 2002. During 2003, the U.S. Congress extended the Act for commercial nuclear facilities through December 31, 2003. However, provisions of the Act remain in effect for existing commercial reactors. Legislation to extend the Act in conjunction with comprehensive energy legislation is currently under debate in Congress. We cannot predict whether the legislation will pass the Congress.

Decommissioning

The NRC has jurisdiction over the decommissioning of nuclear power plants and requires decommissioning funding based upon a formula. The MPSC and FERC regulate the recovery of costs of decommissioning nuclear power plants and both require the use of external trust funds to finance the decommissioning of Fermi 2. Rates approved by the MPSC provide for the recovery of decommissioning costs of Fermi 2. Detroit Edison is continuing to fund FERC jurisdictional amounts for decommissioning even though explicit provisions are not included in FERC rates. We believe the MPSC and FERC collections will be adequate to fund the estimated cost of decommissioning using the NRC formula.

Detroit Edison has established a restricted external trust to hold funds collected from customers for decommissioning and the disposal of low-level radioactive waste. Detroit Edison collected $36 million in 2003, $42 million in 2002 and $38 million in 2001 from customers for decommissioning and low-level radioactive waste disposal. Net unrealized investment gains of $62 million and losses of $39 million in 2003 and 2002, respectively, were recorded as adjustments to the nuclear decommissioning trust funds and regulatory assets. At December 31, 2003, investments in the external trust consisted of approximately 54.8% in publicly traded equity securities, 44.4% in fixed debt instruments and 0.8% in cash equivalents.

At December 31, 2003 and 2002, Detroit Edison had external decommissioning trust funds of $474 million and $377 million, respectively, for the future decommissioning of Fermi 2. At December 31, 2003 and 2002, Detroit Edison had an additional $22 million for the decommissioning of Fermi 1. Detroit Edison also had an external decommissioning trust fund of $22 million for low-level radioactive waste disposal costs at December 31, 2003 and $17 million as of December 31, 2002. It is estimated that the cost of decommissioning Fermi 2, when its license expires in 2025, will be $1.0 billion in 2003 dollars and $3.4 billion in 2025 dollars, using a 6% inflation rate. In 2001, the company began the decommissioning of Fermi 1, with the goal of removing the radioactive material and terminating the Fermi 1 license. The decommissioning of Fermi 1 is expected to be complete by 2009.

As a result of adopting SFAS No. 143, Detroit Edison recorded a retirement obligation liability for the decommissioning of Fermi 1 and 2 and reversed previously recognized decommissioning liabilities. We continue to have liability for the removal of the non-nuclear portion of the plants of $67 million at December 31, 2003.

Nuclear Fuel Disposal Costs

In accordance with the Federal Nuclear Waste Policy Act of 1982, Detroit Edison has a contract with the U.S. Department of Energy (DOE) for the future storage and disposal of spent nuclear fuel from Fermi 2. Detroit Edison is obligated to pay the DOE a fee of one mill per net kilowatthour 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, Detroit Edison is responsible for the spent nuclear fuel storage. Detroit Edison estimates that existing storage capacity will be sufficient until 2007. Detroit Edison has entered into litigation against the DOE for damages caused by the DOE not accepting spent nuclear fuel on a timely basis.

NOTE 6 - JOINTLY OWNED UTILITY PLANT

Detroit Edison's share of jointly owned utility plants at December 31, 2003 was as follows:

	Belle River	Ludington Hydroelectric Pumped Storage
In-service date	1984-1985	1973
Ownership interest	*	49%
Investment (in Millions)	$ 1,587	$ 197
Accumulated depreciation (in Millions)	$ 711	$ 114

*Detroit Edison's ownership interest is 63% in Unit No. 1, 81% of the facilities applicable to Belle River used jointly by the Belle River and St. Clair Power Plants and 75% in common facilities used at Unit No. 2.

Belle River

The Michigan Public Power Agency (MPPA) has an ownership interest in Belle River Unit No. 1 and other related facilities. The MPPA is entitled to 19% of the total capacity and energy of the plant (1,026 MW) and is responsible for the same percentage of the plant's operation, maintenance and capital improvements costs.

Ludington Hydroelectric Pumped Storage

Operation, maintenance and other expenses of the Ludington Hydroelectric Pumped Storage Plant (1,872 MW) are shared by Detroit Edison and Consumers Energy Company in proportion to their respective plant ownership interests.

NOTE 7 - INCOME TAXES

We file a consolidated federal income tax return.

Total income tax benefit varied from the statutory federal income tax rate for the following reasons:

(Dollars in Millions)	2003	2002	2001
Effective federal income tax rate	**(34.4) %**	(16.7)%	(62.6)%
Income tax expense at 35% statutory rate	**$ 125**	$ 175	$ 68
Section 29 tax credits	**(241)**	(250)	(165)
Investment tax credits	**(8)**	(9)	(8)
Depreciation	**(4)**	2	(12)
Goodwill amortization	**—**	—	10
Research expenditures tax credits	**—**	—	(7)
Employee Stock Ownership Plan dividends	**(5)**	(4)	(4)
Other-net	**10**	2	(1)
Income taxes benefit associated with continuing operations	**$ (123)**	$ (84)	$ (119)

Components of income tax benefit were as follows:

(in Millions)	2003	2002	2001
Continuing Operations			
Current federal and other income tax expense	**$ 14**	$ 135	$ 1
Deferred federal income tax benefit	**(137)**	(219)	(120)
	(123)	(84)	(119)
Discontinued operations	**61**	25	9
Total	**$ (62)**	$ (59)	$ (110)

Internal Revenue Code Section 29 provides a tax credit for qualified fuels produced and sold by a taxpayer to an unrelated party during the taxable year. Section 29 tax credits earned but not utilized of $497 million are carried forward indefinitely as alternative minimum tax credits. The majority of our tax credit properties, including all of our synfuel projects, have received private letter rulings from the Internal Revenue Service (IRS) that provide assurance as to the appropriateness of using these credits to offset taxable income, however, these tax credits are subject to IRS audit and adjustment.

As a result of the MCN Energy acquisition we have a net operating loss carryforward of $239 million that expires in years 2018 through 2020. We do not believe that a valuation allowance is required, as we expect to utilize the loss carryforward prior to its expiration.

Deferred tax assets and liabilities are recognized for the estimated future tax effect of temporary differences between the tax basis of assets or liabilities and the reported amounts in the financial statements. Deferred tax assets and liabilities are classified as current or noncurrent according to the classification of the related assets or liabilities. Deferred tax assets and liabilities not related to assets or liabilities are classified according to the expected reversal date of the temporary differences.

Deferred income tax assets (liabilities) were comprised of the following at December 31:

(in Millions)	2003	2002
Property	**$ (1,124)**	$ (1,179)
Securitized regulatory assets	**(827)**	(871)
Alternative minimum tax credit carryforward	**497**	381
Merger basis differences	**132**	186
Pension and benefits	**(50)**	216
Net operating loss	**84**	114
Other	**380**	282
	$ (908)	$ (871)
Deferred income tax liabilities	**$ (2,525)**	$ (2,564)
Deferred income tax assets	**1,617**	1,693
	$ (908)	$ (871)

The IRS is currently conducting audits of our federal income tax returns for the years 1998 through 2001 and of the MCN Energy federal income tax returns for 1999 through May 31, 2001. In addition, four of our synfuel facilities are under audit by the IRS for 2001. We believe that our accrued tax liabilities are adequate for all years.

NOTE 8 – COMMON STOCK AND EARNINGS PER SHARE

Common Stock

In June 2002, we issued 6.325 million shares of common stock at $43.25 per share, grossing $274 million. Net proceeds from the offering were approximately $265 million.

On May 31, 2001, we issued approximately 29 million shares of common stock, valued at $1.06 billion, as part of the consideration to purchase all of the outstanding common stock of MCN Energy. See Note 3 – Acquisitions and Dispositions. The newly issued shares were valued at the average market price of our common stock on February 28, 2001, the announcement date of the revised merger agreement.

In 2001, DTE Energy repurchased approximately 10.5 million shares of common stock with a total cost of approximately $438 million.

Under the DTE Energy Company Long-Term Incentive Plan, we grant non-vested stock awards to management. At the time of grant, DTE Energy records the fair value of the non-vested awards as unearned compensation, which is reflected as a reduction in common stock. The number of non-vested stock awards is included in the number of common shares outstanding; however, for purposes of computing basic earnings per share, non-vested stock awards are excluded.

Shareholders' Rights Plan

We have a Shareholders' Rights Plan designed to maximize shareholders' value should DTE Energy be acquired. The rights are attached to and trade with shares of DTE Energy's common stock until they are exercisable upon certain triggering events. The rights expire in 2007.

Earnings per Share

We report both basic and diluted earnings per share. Basic earnings per share is computed by dividing income from continuing operations by the weighted average number of common shares outstanding during the period. Diluted earnings per share assume the issuance of potentially dilutive common shares outstanding during the period and the repurchase of common shares that would have occurred with proceeds from the assumed issuance. Diluted earnings per share assume the exercise of stock options, vesting of non-vested stock awards, and the issuance of performance share awards. A reconciliation of both calculations is presented in the following table:

(in Millions, except per share amounts)	2003	2002	2001
Basic Earnings per Share			
Income from continuing operations	**$ 480.4**	$ 585.7	$ 308.7
Average number of common shares outstanding	**167.7**	164.0	153.1
Earnings per share of common stock based on average number of shares outstanding	**$ 2.87**	$ 3.57	$ 2.02
Diluted Earnings per Share			
Income from continuing operations	**$ 480.4**	$ 585.7	$ 308.7
Average number of common shares outstanding	**167.7**	164.0	153.1
Incremental shares from stock-based awards	**.6**	.8	.7
Average number of dilutive shares outstanding	**168.3**	164.8	153.8
Earnings per share of common stock assuming issuance of incremental shares	**$ 2.85**	$ 3.55	$ 2.01

Options to purchase approximately five million shares of common stock were not included in the computation of diluted earnings per share because the options' exercise price was greater than the average market price of the common shares, thus making these securities anti-dilutive.

NOTE 9 - LONG-TERM DEBT AND PREFERRED SECURITIES

Long Term Debt

Our long-term debt outstanding and weighted average interest rates of debt outstanding at December 31 were:

(in Millions)	2003	2002
DTE Energy Debt, Unsecured		
6.6% due 2004 to 2033	**$2,005**	$1,948
Detroit Edison Taxable Debt, Principally Secured		
6.2% due 2005 to 2034	**1,485**	1,812
Detroit Edison Tax Exempt Revenue Bonds		
5.7% due 2004 to 2032	**1,175**	1,208
MichCon Taxable Debt, principally secured		
6.5% due 2005 to 2039	**772**	775
Quarterly Income Debt Securities (QUIDS)		
7.8% due 2026 to 2038	**385**	385
Non-Recourse Debt	**78**	119
Other Long-Term Debt	**106**	329
	6,006	6,576
Less amount due within one year	**(382)**	(920)
	$ 5,624	$5,656
Securitization Bonds	**$1,585**	$1,673
Less amount due within one year	**(89)**	(88)
	$ 1,496	$ 1,585
Equity-Linked Securities	**$ 185**	$ 191
Trust Preferred - Linked Securities		
8.625% due 2038	**$ 103**	$ 103
7.8% due 2032	**186**	186
	$ 289	$ 289

During 2003 and 2002, we issued and optionally redeemed long-term debt consisting of the following:

2003

- Issued $400 million of DTE Energy 6-3/8% senior notes maturing in April 2033. In conjunction with this issuance, DTE Energy exchanged $100 million principal amount of existing Enterprises debt due April 2008. The exchange premium and other costs associated with the original debt were deferred and amortized to interest expense over the term of the new debt.
- Redeemed $100 million of DTE Energy 6.17% Remarketed Notes maturing in 2038
- Issued $49 million of Detroit Edison 5.5% tax exempt bonds maturing in 2030
- Redeemed $49 million of Detroit Edison 6.55% tax-exempt bonds maturing in 2024
- Issued $200 million of MichCon 5.7% senior notes maturing in March 2033

2002

- Issued $200 million of DTE Energy senior notes bearing interest at 6.65 % and maturing in 2009
- Issued $172.5 million of DTE Energy equity-linked debt securities as subsequently discussed
- Issued $225 million of Detroit Edison senior notes bearing interest at 5.20 % and maturing in 2012
- Issued $225 million of Detroit Edison senior notes bearing interest at 6.35 % and maturing in 2032
- Issued $64 million of Detroit Edison tax exempt bonds bearing interest at 5.45% and issued $56 million of Detroit Edison tax exempt bonds bearing interest at 5.25%, both maturing in 2032.

In the years 2004 - 2008, our long-term debt maturities are $467 million, $512 million, $680 million, $174 million and $455 million, respectively.

Remarketable Securities

At December 31, 2003, $175 million of notes of Detroit Edison and MichCon were subject to periodic remarketings, no remarketings will take place in 2004. We direct the remarketing agents to remarket these securities at the lowest interest rate necessary to produce a par bid. In the event that a remarketing fails, we would be required to purchase these securities.

Quarterly Income Debt Securities (QUIDS)

Each series of QUIDS provides that interest will be paid quarterly. However, Detroit Edison has the right to extend the interest payment period on the QUIDS for up to 20 consecutive interest payment periods. Interest would continue to accrue during the deferral period. If this right is exercised, Detroit Edison may not declare or pay dividends on, or redeem, purchase or acquire, any of its capital stock during the deferral period.

Equity-Linked Securities

In June 2002, we issued 6.9 million equity security units with gross proceeds from the issuance of $172.5 million. An equity security unit consists of a stock purchase contract and a senior note of DTE Energy. Under the stock purchase contracts, we will sell, and equity security unit holders must buy, shares of DTE Energy common stock in August 2005 for $172.5 million. The issue price per share and the exact number of common shares to be sold is dependent on the market value of a share in August 2005. The issue price will be not less than $43.25 or more than $51.90 per common share, with the corresponding number of shares issued of not more than 4.0 million or less than 3.3 million shares. We are also obligated to pay the security unit holders a quarterly contract adjustment payment at an annual rate of 4.15% of the stated amount until the purchase contract settlement date. We recorded the present value of the contract adjustment payments of $26 million in long-term debt with an offsetting reduction in shareholders' equity. The liability is reduced as the contract adjustment payments are made.

Each senior note has a stated value of $25, pays an annual interest rate of 4.60% and matures in August 2007. The senior notes are pledged as collateral to secure the security unit holders' obligation to purchase DTE Energy common stock under the stock purchase contracts. The security unit holders may satisfy their obligations under the stock purchase contracts by allowing the senior notes to be remarketed with proceeds being paid to DTE Energy as consideration for the purchase of stock under the stock purchase contracts. Alternatively, holders may choose to continue holding the senior notes and use cash as consideration for the purchase of stock under the stock purchase contracts.

Net proceeds from the equity security unit issuance totaled $167 million. Expenses incurred in connection with this issuance totaled $5.6 million and were allocated between the senior notes and the stock purchase contracts. The amount allocated to the senior notes was deferred and will be recognized as interest expense over the term of the notes. The amount allocated to the purchase contracts was charged to equity.

Trust Preferred-Linked Securities

We have interests in various unconsolidated trusts that were formed for the sole purpose of issuing preferred securities and lending the gross proceeds to DTE Energy. The sole assets of the trusts are debt securities of DTE Energy with terms similar to those of the related preferred securities. Payments we make are used by the trusts to make cash distributions on the preferred securities it has issued.

We have the right to extend interest payment periods on the debt securities. Should we exercise this right, we cannot declare or pay dividends on, or redeem, purchase or acquire, any of our capital stock during the deferral period.

DTE Energy has issued certain guaranties with respect to payments on the preferred securities. These guaranties, when taken together with our obligations under the debt securities and related indenture, provide full and unconditional guarantees of the trusts' obligations under the preferred securities.

Financing costs for these issuances were paid for and deferred by DTE Energy. These costs are being amortized using the straight-line method over the estimated lives of the related securities.

The $100 million of 8.625% preferred securities, due 2038, was called in December 2003 and was redeemed in January 2004. Accordingly, the underlying DTE Energy debt security was also simultaneously redeemed.

Cross Default Provisions

Substantially all of the net utility properties of Detroit Edison and MichCon are subject to the lien of mortgages. Should Detroit Edison or MichCon fail to timely pay their indebtedness under these mortgages, such failure will create cross defaults in the indebtedness of DTE Energy Corporate.

Preferred and Preference Securities – Authorized and Unissued

At December 31, 2003, DTE Energy had 5 million shares of preferred stock without par value authorized, with no shares issued. Of such amount, 1.6 million shares are reserved for issuance in accordance with the Shareholders' Rights Plan.

At December 31, 2003, Detroit Edison had 6.75 million shares of preferred stock with a par value of $100 per share and 30 million shares of preference stock with a par value of $1 per share authorized, with no shares issued.

At December 31, 2003, Enterprises had 25 million shares of preferred stock without par value authorized, with no shares issued.

At December 31, 2003, MichCon had 7 million shares of preferred stock with a par value of $1 per share and 4 million shares of preference stock with a par value of $1 per share authorized, with no shares issued.

NOTE 10 - SHORT-TERM CREDIT ARRANGEMENTS AND BORROWINGS

In October 2003, we entered into a $350 million 364-day unsecured revolving credit facility and a $350 million three-year unsecured revolving credit facility with a syndicate of banks. These credit facilities may be utilized for general corporate borrowings, but primarily are intended to provide liquidity support for DTE Energy's commercial paper program up to $700 million. In addition, we had approximately $100 million of letters of credit outstanding against these facilities at December 31, 2003, which represent guarantees to third parties under which no amounts were outstanding. These agreements require the Company to maintain a debt to total capitalization ratio of no more than .65 to l and "earnings before interest, taxes, depreciation and amortization" (EBITDA) to interest ratio of no less than 2 to 1. DTE Energy is currently in compliance with these financial covenants. Also, in October 2003, DTE Energy's wholly-owned subsidiaries, Detroit Edison and MichCon, entered into similar revolving credit facilities. Detroit Edison entered into a $137.5 million, 364-day facility and a $137.5 million, three-year facility. MichCon entered into a $162.5 million, 364-day facility and a $162.5 million, three-year facility. Should either Detroit Edison or MichCon have delinquent debt obligations of at least $25 million to any creditor, such delinquency will be considered a default under DTE Energy's credit agreements.

As of December 31, 2003, we had outstanding commercial paper of $239 million and other short-term borrowings of $31 million. At December 31, 2002, we had outstanding commercial paper of $413 million and other short-term borrowings of $1 million.

Detroit Edison has a $200 million short-term financing agreement secured by customer accounts receivable. This agreement contains certain covenants related to the delinquency of accounts receivable. Detroit Edison is currently in compliance with these covenants. We had $100 million outstanding under this financing agreement at December 31, 2003.

The weighted average interest rates for short-term borrowings were 1.9% and 1.7% at December 31, 2003 and 2002, respectively.

NOTE 11 – CAPITAL AND OPERATING LEASES

Lessee – We lease various assets under capital and operating leases, including locomotives, coal cars, a gas storage field, office buildings, a warehouse, computers, vehicles and other equipment. The lease arrangements expire at various dates through 2029. Portions of the office buildings are subleased to tenants. Future minimum lease payments under non-cancelable leases at December 31, 2003 were:

(in Millions)	Capital Leases	Operating Leases
2004	$ 12	$ 72
2005	12	70
2006	14	58
2007	10	54
2008	11	46
Thereafter	50	457
Total minimum lease payments	109	$ 757
Less imputed interest	(28)	
Present value of net minimum lease payments	81	
Less current portion	(6)	
Non-current portion	$ 75	

Total minimum lease payments for operating leases have not been reduced by future minimum sublease rentals totaling $8 million under non-cancelable subleases expiring at various dates to 2019.

Rental expenses for operating leases was $73 million in 2003, $40 million in 2002 and $19 million in 2001.

Lessor - MichCon leases a portion of its pipeline system to the Vector Pipeline Partnership through a capital lease contract that expires in 2020, with renewal options extending for five years. The components of the net investment in the capital lease at December 31, 2003, were as follows:

(in Millions)	
2004	$ 9
2005	9
2006	9
2007	9
2008	9
Thereafter	107
Total minimum future lease receipts	152
Residual value of leased pipeline	40
Less - unearned income	(109)
Net investment in capital lease	83
Less - current portion	(1)
	$ 82

NOTE 12 - FINANCIAL AND OTHER DERIVATIVE INSTRUMENTS

We comply with SFAS No. 133, "*Accounting for Derivative Instruments and Hedging Activities*." SFAS No. 133, established accounting and reporting standards for derivative instruments and hedging activities. Listed below are important SFAS No. 133 requirements:

- All derivative instruments must be recognized as assets or liabilities and measured at fair value, unless they meet the normal purchases and sales exemption.
- The accounting for changes in fair value depends upon the purpose of the derivative instrument and whether it is designated as a hedge and qualifies for hedge accounting.
- Special accounting is allowed for a derivative instrument qualifying as a hedge and designated as a hedge for the variability of cash flow associated with a forecasted transaction. Gain or loss associated with the effective portion of the hedge is recorded in other comprehensive income. The ineffective portion is recorded to earnings. Amounts recorded in other comprehensive income will be reclassified to net income when the forecasted transaction affects earnings.
- If a cash flow hedge is discontinued because it is likely the forecasted transaction will not occur, net gains or losses are immediately recorded into earnings.
- Special accounting is allowed for a derivative instrument qualifying as a hedge and designated as a hedge of the changes in fair value of an existing asset, liability or firm commitment. Gain or loss on the hedging instrument is recorded into earnings. The gain or loss on the underlying asset, liability or firm commitment is also recorded into earnings.

Our primary market risk exposure is associated with commodity prices, credit, interest rates and foreign currency. We have risk management policies to monitor and decrease market risks. We use derivative instruments to manage some of the exposure. Except for the activities of the Energy Marketing & Trading segment, we do not hold or issue derivative instruments for trading purposes. The fair value of all derivatives is shown as "assets or liabilities from risk management and trading activities" in the consolidated statement of financial position.

Commodity Price Risk

Regulated Operations

Detroit Edison uses forward energy, capacity, and futures contracts to manage changes in the price of electricity and natural gas. Changes in fair value of derivatives are recognized currently in earnings, unless hedge accounting and the normal purchase and sale exceptions apply. Changes in fair value of derivatives designated and qualifying as an effective cash flow hedge are recorded as a component of other comprehensive loss and reclassified into earnings. Any changes in fair value of ineffective cash flow hedges are recognized currently in earnings. Changes in fair value of normal contracts are not recorded. These contracts are recorded on an accrual basis. There were no commodity price risk cash flow hedges for regulated operations at December 31, 2003.

Detroit Edison operating policy is that transactions for electricity or fuel are not done in a speculative manner, but to optimize the efficiency of the power supply costs. All contracts entered into by Detroit Edison to sell energy are physically delivered. All purchases of power are considered capacity contracts under SFAS No. 133 (as amended by SFAS No. 138 and SFAS No. 149). In addition, the summer shortfall calculation submitted to the MPSC is in support of our short positions. It is based on management's judgment of the above criteria that Detroit Edison's commodity contracts are considered normal.

MichCon has firm-priced contracts for a substantial portion of its expected gas supply requirements through 2004. These contracts are designated and qualify for the normal purchases exception under SFAS No. 133. Accordingly, MichCon does not account for such contracts as derivatives.

Non-Regulated Operations

Energy Marketing & Trading markets and trades wholesale electricity and natural gas physical products, trades financial instruments, and provides risk management services utilizing energy commodity derivative instruments. Forwards, futures, options and swap agreements are used to manage exposure to the risk of market price and volume fluctuations on its operations. This risk minimization strategy is being accounted for by marking to market its commodity forwards and financial derivatives so they substantially offset. This fair value accounting better aligns financial reporting with the way the business is managed and its performance measured. Unrealized gains and losses resulting from marking to market commodity-related physical and financial derivatives utilized in trading operations are recorded as adjustments to revenues.

Energy Marketing & Trading experiences earnings volatility as a result of its gas inventory and other non-derivative assets that do not qualify for mark to market accounting under generally accepted accounting principles. Although the risks associated with these asset positions are substantially offset, requirements to revalue the underlying trades will result in unrealized gains and losses that will eventually reverse upon settlement.

Credit Risk

We are exposed to credit risk if customers or counterparties do not comply with their contractual obligations. We maintain credit policies that significantly minimize overall credit risk. These policies include an evaluation of potential customers' and counterparties' financial condition, credit rating, collateral requirements or other credit enhancements such as letters of credit or guarantees. We use standardized agreements that allow the netting of positive and negative transactions associated with a single counterparty.

Interest Rate Risk

We use interest rate swaps to hedge the risk associated with interest rate payments and expense. During 2000, we entered into a series of interest rate swaps and treasury locks to limit our sensitivity to market interest rate risk associated with the issuance of long-term debt used to acquire MCN Energy. Such instruments were designated as cash flow hedges. In the first quarter of 2001, a loss of approximately $5 million was reclassified from accumulated other comprehensive loss into earnings. We made this decision since it was probable that certain transactions associated with the issuance of long-term debt would not occur within the originally anticipated time frame. This loss was reported as a component of interest expense in the consolidated statement of operations. In 2001, we issued long-term debt with varying maturities and terminated these hedges at a cost of $83 million. The corresponding loss on these instruments is included in other comprehensive loss. During the next 30 years, amounts recorded in other comprehensive loss will be reclassified to interest expense as the related interest affects earnings. In 2004 we estimate reclassifying $10 million of losses into interest expense.

Foreign Currency Risk

During 2003, we entered into forward purchases of foreign currency contracts to hedge fixed Canadian dollar commitments existing under power purchase and sale contracts and gas transportation contracts. We entered into these contracts to mitigate any price volatility with respect to fluctuations of the Canadian dollar relative to the U.S. dollar. Certain of these contracts are designated as cash flow hedges and were fully effective as of December 31, 2003.

Fair Value of Other Financial Instruments

The fair value of financial instruments is determined by using various market data and other valuation techniques. The table below shows the fair value relative to the carrying value for non-affiliated long-term debt securities:

	2003		2002	
	Fair Value	**Carrying Value**	**Fair Value**	**Carrying Value**
Long-Term Debt	**$8.5 billion**	**$7.9 billion**	$8.9 billion	$8.2 billion

NOTE 13 - COMMITMENTS AND CONTINGENCIES

Synthetic Fuel Operations

We operate nine synthetic fuel production facilities, four of which are wholly owned. Synfuel facilities chemically change coal, including waste and marginal coal, into a synthetic fuel as determined under applicable IRS rules. Section 29 of the Internal Revenue Code provides tax credits for the production and sale of solid synthetic fuels produced from coal. To qualify for the Section 29 tax credits, the synthetic fuel must meet three primary conditions: (1) there must be a significant chemical change in the coal feedstock, (2) the product must be sold to an unaffiliated entity, and (3) the production facility must have been placed in service before July 1, 1998. In addition to meeting the qualifying conditions, a taxpayer must have sufficient taxable income to earn the Section 29 credits.

In May 2003, the IRS suspended the issuance of PLRs relating to synthetic fuel projects pending their review of issues concerning chemical change which is the basis for earning Section 29 tax credits. In October 2003, the IRS concluded its assessment of the chemical change process involved in synfuel production and resumed issuing PLRs. The IRS determined that the test procedures and results used by taxpayers are scientifically valid if the procedures are applied in a consistent and unbiased manner. The Company believes that its synthetic fuel facilities currently meet the new, more stringent sampling and data/record retention requirements announced by the IRS. We had previously received favorable PLRs from the IRS on seven of our nine synfuel plants. In November 2003, we received favorable PLRs for the remaining two synfuel plants. The IRS is currently reviewing procedures and results at four of our synfuels plants in conjunction with their audits of our federal income tax returns for 2001. We believe our synthetic fuel plants operate in accordance with the PLRs. Through December 31, 2003, we have generated approximately $484 million of synfuel tax credits.

To optimize tax credits generated from these facilities, we implemented a series of initiatives, including selling interests in synfuel projects and monetizing certain in-the-money derivatives contracts which allowed us to fully utilize the tax credits generated in 2003. We are continuing our efforts to sell interests in all of our synfuel projects. Sales of interests in synfuel projects allow us to accelerate cash flow and taxable income, while maintaining a stable net income base. As the sale of interests in synfuel projects usually requires the reconfirmation of the PLR, the timing and number of our synfuel project interest sales were influenced by the IRS' five month suspension of issuing new and reconfirming PLRs.

The U.S. Senate Permanent Subcommittee on Investigations of the Committee on Governmental Affairs has begun an investigation of the synthetic fuel industry and its producers. DTE Energy, along with other industry participants, received a request to produce certain documents pertaining to its synfuel operations. DTE Energy is in the process of complying with this request. We have no further knowledge of the scope of the investigation, when the investigation will be completed or the potential results of the investigation.

Guarantees

In certain circumstances we enter into contractual guarantees. We may guarantee another entity's obligation in the event it fails to perform. We may provide guarantees in certain indemnification agreements. Finally, we may provide indirect guarantees of the indebtedness of others. Below are the details of specific material guarantees we currently provide. Our other guarantees are not individually material and total approximately $26 million at December 31, 2003.

Sale of Tax Credit Properties

We have provided certain guarantees and indemnities in conjunction with the sales of interests in our synfuel facilities. The guarantees cover general commercial, environmental and tax-related exposure and will survive until 90 days after expiration of all applicable statute of limitations, or indefinitely, depending on the nature of the guaranty. We estimate that our maximum liability under these guarantees at December 31, 2003 totals $300 million.

Parent Company Guarantee of Subsidiary Obligations

We have issued guarantees for the benefit of various non-regulated subsidiary transactions. In the event that DTE Energy's credit rating is downgraded below investment grade, certain of these guarantees would require us to post cash or letters of credit valued at approximately $290 million at December 31, 2003. This estimated amount fluctuates based upon the provisions and maturities of the underlying agreements.

Personal Property Taxes

Detroit Edison, MichCon and other Michigan utilities have asserted that Michigan's valuation tables result in the substantial overvaluation of utility personal property. Valuation tables established by the Michigan State Tax Commission (STC) are used to determine the taxable value of personal property based on the property's age. In November 1999, the STC approved new valuation tables that more accurately recognize the value of a utility's personal property. The new tables became effective in 2000 and are currently used to calculate property tax expense. However, several local taxing jurisdictions have taken legal action attempting to prevent the STC from implementing the new valuation tables and have continued to prepare assessments based on the superseded tables. The legal actions regarding the appropriateness of the new tables were before the Michigan Tax Tribunal (MTT) which, in April 2002, issued its decision essentially affirming the validity of the STC's new tables. In June 2002, petitioners in the case filed an appeal of the MTT's decision with the Michigan Court of Appeals. On January 20, 2004, the Michigan Court of Appeals upheld the validity of the new tables.

Detroit Edison and MichCon record property tax expense based on the new tables. Detroit Edison and MichCon will seek to apply the new tables retroactively and to ultimately settle the pending tax appeals related to 1997 through 1999. This is a solution supported by the STC in the past.

Energy Gas Environmental Matters

Prior to the construction of major natural gas pipelines, gas for heating and other uses was manufactured from processes involving coal, coke or oil. Enterprises (MichCon and Citizens) owns, or previously owned, 18 such former manufactured gas plant (MGP) sites.

During the mid-1980's, Enterprises conducted preliminary environmental investigations at former MGP sites, and some contamination related to the by-products of gas manufacturing was discovered at each site. The existence of these sites and the results of the environmental investigations have been reported to the MDEQ. None of these former MGP sites is on the National Priorities List prepared by the EPA.

Enterprises is remediating seven of the former MGP sites and conducting more extensive investigations at six other former MGP sites. Enterprises received MDEQ closure of one site and a determination that it is not a responsible party for three other sites. Enterprises received closure from the EPA in 2002 for one site.

In 1984, Enterprises established a $12 million reserve for environmental investigation and remediation. During 1993, MichCon received MPSC approval of a cost deferral and rate recovery mechanism for investigation and remediation costs incurred at former MGP sites in excess of this reserve.

Enterprises employed outside consultants to evaluate remediation alternatives for these sites, to assist in estimating its potential liabilities and to review its archived insurance policies. The findings of these investigations indicate that the estimated total expenditures for investigation and remediation activities for these sites could range from $30 million to $170 million based on undiscounted 1995 costs. As a result of these studies, Enterprises accrued an additional liability and a corresponding regulatory asset of $35 million during 1995.

During 2003, Enterprises spent $1.5 million investigating and remediating these former MGP sites. At December 31, 2003, the reserve balance was $23 million of which $5 million was classified as current. Any significant change in assumptions, such as remediation techniques, nature and extent of contamination and regulatory requirements, could impact the estimate of remedial action costs for the sites and, therefore, have an effect on the company's financial position and cash flows. However, we believe the cost deferral and rate recovery mechanism approved by the MPSC will prevent environmental costs from having a material adverse impact on our results of operations.

Commitments

Detroit Edison has an Energy Purchase Agreement to purchase steam and electricity from the Greater Detroit Resource Recovery Authority (GDRRA). Under the Agreement, Detroit Edison will purchase steam through 2008 and electricity through June 2024. In 1996, a special charge to income was recorded that included a reserve for steam purchase commitments in excess of replacement costs from 1997 through 2008. The reserve for steam purchase commitments is being amortized to fuel, purchased power and gas expense with non-cash accretion expense being recorded through 2008. In 2001, due to changes in estimated future replacement costs we reduced the reserve for future steam purchase commitments by $22 million. We purchased $30 million of steam and electricity in 2003, $37 million in 2002 and $41 million in 2001. We estimate annual steam and electric purchase commitments from 2004 until 2008 will not exceed $150 million. As discussed in Note 3 – Acquisitions and Dispositions, in January 2003, we sold the steam heating business of Detroit Edison to Thermal Ventures II, LLP. Due to terms of the sale, Detroit Edison remains contractually obligated to GDRRA until 2008 and recorded an additional liability of $20 million for future commitments. Also, we have guaranteed bank loans that Thermal Ventures II, LLP may use for capital improvements to the steam heating system.

The EPA issued ozone transport regulations and, in December, 2003, proposed additional emission regulations relating to ozone, fine particulate and mercury air pollution. The new rules have led to additional controls on fossil-fueled power plants to reduce nitrogen oxides, sulfur dioxide, carbon dioxide and particulate emissions. To comply with these new controls, Detroit Edison has spent approximately $560 million through December 2003 and estimates that it will spend approximately $40 million in 2004 and incur up to an additional approximately $1.2 billion of future capital expenditures over the next five to eight years to satisfy both the existing and proposed new control requirements. Under the June 2000 Michigan restructuring legislation, beginning January 1, 2004, annual return of and on this capital expenditure, in excess of current depreciation levels, would be deferred in ratemaking, until after the expiration of the rate cap period, presently expected to end December 31, 2005.

To ensure a reliable supply of natural gas at competitive prices, Enterprises has entered into long-term purchase and transportation contracts with various suppliers and producers. In general, purchases are under fixed price and volume contracts or formulas based on market prices. Enterprises has firm purchase commitments through 2010 for approximately 342 Bcf of gas. Enterprises expects that sales, based on warmer-than-normal weather, will exceed its minimum purchase commitments. Enterprises has long-term transportation and storage contracts with various companies expiring on various dates through the year 2021. Enterprises is also committed to pay demand charges of approximately $68 million during 2004 related to firm purchase and transportation agreements.

In February 2004, Enterprises terminated a long-term gas exchange agreement and modified our future purchase commitments under a related transportation agreement with an interstate pipeline company, effective March 31, 2004. The agreements were at rates that were not reflective of current market conditions and had been fair valued under generally accepted accounting principles. In 2002, the fair value of the transportation agreement was frozen when it no longer met the definition of a derivative as a result of FERC Order 637. The fair value amounts were being amortized to income over the life of the related agreements, representing a net liability of approximately $75 million as of December 31, 2003. We are currently negotiating new agreements with the interstate pipeline company. We will record an appropriate adjustment to the liability after all related agreements have been finalized.

At December 31, 2003, we have also entered into long-term fuel supply commitments through 2008 of approximately $405 million. We estimate that 2004 base level capital expenditures will be $1.0 billion. We have made certain commitments in connection with expected capital expenditures.

Bankruptcies

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

Other

Several Midwest utilities seek to recover lost transmission revenues associated with the creation of multiple regional transmission organizations in the Midwest. Positions advocated by several parties in a FERC proceeding could require that Detroit Edison and its customers be responsible for increased transmission costs. Detroit Edison continues to actively participate in this proceeding and depending upon the outcome would subsequently seek rate recovery of these costs.

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.

See Note 4 and Note 5 for a discussion of contingencies related to Regulatory Matters and Nuclear Operations.

NOTE 14 - RETIREMENT BENEFITS AND TRUSTEED ASSETS

Qualified Pension Plan Benefits

We have defined benefit retirement plans for eligible union and nonunion employees. Prior to December 31, 2001, we had three separate defined benefit retirement plans. Effective December 31, 2001, two of the defined benefit retirement plans merged into one plan. The plans are noncontributory, cover substantially all employees and provide retirement benefits based on the employees' years of benefit service, average final compensation and age at retirement. Certain nonrepresented employees are covered under cash balance benefits based on annual employer contributions and interest credits. Our policy is to fund pension costs by contributing the minimum amount required by the Employee Retirement Income Security Act (ERISA) and additional amounts we deem appropriate.

Net pension cost (credit) for the years ended December 31 includes the following components:

(in Millions)	2003	2002	2001
Service Cost	**$ 48**	$ 43	$ 40
Interest Cost	**164**	162	140
Expected Return on Plan Assets	**(211)**	(223)	(193)
Amortization of			
Net loss	**38**	2	—
Prior service cost	**8**	9	10
Net transition asset	**—**	(2)	(5)
Special Termination Benefits (Note 3)	**—**	—	167
Net Pension Cost (Credit)	**$ 47**	$ (9)	$ 159

Table of Contents

The following table reconciles the obligations, assets and funded status of the plans as well as the amounts recognized as prepaid pension cost or pension liability in the consolidated statement of financial position at December 31:

(in Millions)	2003	2002
Measurement Date	December 31	December 31
Accumulated Benefit Obligation at the End of the Period	**$ 2,556**	$ 2,299
Projected Benefit Obligation at the Beginning of the Period	**$ 2,499**	$ 2,219
Service Cost	**48**	43
Interest Cost	**164**	162
Actuarial Loss	**201**	235
Benefits Paid	**(159)**	(160)
Plan Amendments	**(8)**	—
Projected Benefit Obligation at the End of the Period	**$ 2,745**	$ 2,499
Plan Assets at Fair Value at the Beginning of the Period	**$ 1,845**	$ 2,183
Actual Return on Plan Assets	**440**	(213)
Company Contributions	**222**	35
Benefits Paid	**(159)**	(160)
Plan Assets at Fair Value at the End of the Period	**$ 2,348**	$ 1,845
Funded Status of the Plans	**$ (397)**	$ (654)
Unrecognized		
Net loss	**1,010**	1,080
Prior service cost	**41**	54
Net Amount Recognized	**$ 654**	$ 480
Amount Recorded as:		
Prepaid Pension Assets	**$ 181**	$ 172
Accrued Pension Liability	**(287)**	(531)
Regulatory Asset	**572**	—
Accumulated Other Comprehensive Loss	**147**	785
Intangible Asset	**41**	54
	$ 654	$ 480

Assumptions used in determining the projected benefit obligation at December 31 are listed below:

	2003	2002	2001
Discount rate	**6.25%**	6.75%	7.25%
Annual increase in future compensation levels	**4.0%**	4.0%	4.0%

Assumptions used in determining net pension costs at December 31 are listed below:

	2003	2002	2001
Discount rate	**6.75%**	7.25%	7.50%
Annual increase in future compensation levels	**4.0%**	4.0%	4.0%
Expected long-term rate of return on Plan assets	**9.0%**	9.5%	9.5%

We employ a consistent formal process in determining the long-term rate of return for various asset classes. We evaluate input from our consultants, including their review of historic financial market risks and returns and long-term historic relationships between the asset classes of equities, fixed income and other assets, consistent with the widely accepted capital market principle that asset classes with higher volatility generate a greater return over the long-term. Current market factors such as inflation, interest rates, asset class risks and asset class returns are evaluated and considered before long-term capital market assumptions are determined. The long-term portfolio return is also established employing a consistent formal process, with due consideration of diversification, active investment management and rebalancing. Peer data is reviewed to check for reasonability.

We employ a total return investment approach whereby a mix of equities, fixed income and other investments are used to maximize the long-term return of plan assets consistent with prudent levels of risk. The intent of this strategy is to minimize plan expenses over the long-term. Risk tolerance is established through consideration of future plan cash flows, plan funded status, and corporate financial considerations. The investment portfolio contains a diversified blend of equity, fixed income and other investments. Furthermore, equity investments are diversified across U.S and non-U.S. stocks, growth and value investment styles, and large and small market capitalizations. Other assets such as private equity and absolute return funds are used judiciously to enhance long term returns while improving portfolio diversification. Derivatives may be used to gain market exposure in an efficient and timely manner; however, derivatives may not be used to leverage the portfolio beyond the market value of the underlying investments. Investment risk is measured and monitored on an ongoing basis through annual liability measurements, periodic asset/liability studies, and quarterly investment portfolio reviews.

Our Plans' weighted-average asset allocations by asset category at December 31 are as follows:

	2003	2002
Equity Securities	**67%**	62%
Debt Securities	**27**	31
Other	**6**	7
	100%	100%

Our Plans' weighted-average asset target allocations by asset category at December 31, 2003 are as follows:

Equity Securities	**65%**
Debt Securities	**28**
Other	**7**
	100%

In December 2002, we recognized an additional minimum pension liability as required under SFAS No. 87, "*Employers' Accounting for Pensions*." An additional pension liability may be required when the accumulated benefit obligation of the plan exceeds the fair value of plan assets. Under SFAS No. 87, we recorded an additional minimum pension liability of $839 million, ($531 million after netting the previously recognized prepaid pension asset associated with the non represented plan), an intangible asset of $54 million and other comprehensive loss of $785 million ($510 million after tax). In 2003, Detroit Edison reclassified $572 million of other comprehensive loss related to the minimum pension liability to a regulatory asset.

At December 31, 2003 the minimum pension liability was $760 million, intangible asset was $41 million, regulatory asset was $572 million, other comprehensive loss was $147 million ($96 million after tax) and deferred taxes were $51 million.

We plan on making a $170 million contribution of DTE Energy common stock to our defined benefit retirement plans in the first quarter of 2004. A contribution is not required under ERISA.

We also sponsor defined contribution retirement savings plans. Participation in one of these plans is available to substantially all represented and nonrepresented employees. We match employee contributions up to certain predefined limits based upon eligible compensation, the employee's contribution rate and years of credited service. The cost of these plans was $26 million in 2003, $25 million in 2002 and $26 million in 2001.

Nonqualified Pension Benefit Plans

We maintain supplemental nonqualified, noncontributory, retirement benefit plans for selected management employees. These plans provide for benefits that supplement those provided by DTE Energy's other retirement plans.

Net pension cost for the years ended December 31 includes the following components:

(in Millions)	2003	2002	2001
Service Cost	**$ 2**	$ 1	$ 1
Interest Cost	**4**	3	2
Amortization of			
Net loss	**1**	1	—
Prior service cost	**—**	1	1
Special Termination Benefits (Note 3)	**—**	—	6
Net Pension Cost	**$ 7**	$ 6	$10

The following table reconciles the obligations, assets and funded status of the plans as well as the amounts recognized as an accrued pension liability in the consolidated statement of financial position at December 31:

(in Millions)	2003	2002
Measurement Date	December 31	December 31
Accumulated Benefit Obligation at the End of the Period	**$ 57**	$ 49
Projected Benefit Obligation at the Beginning of the Period	**$ 50**	$ 42
Service Cost	**2**	1
Interest Cost	**4**	3
Actuarial Loss	**6**	7
Benefits Paid	**(3)**	(3)
Projected Benefit Obligation at the End of the Period	**$ 59**	$ 50
Plan Assets at Fair Value at the Beginning of the Period	**$ —**	$ —
Company Contributions	**3**	3
Benefits Paid	**(3)**	(3)
Plan Assets at Fair Value at the End of the Period	**$ —**	$ —
Funded Status of the Plans	**$ (59)**	$ (50)
Unrecognized		
Net loss	**18**	12
Prior service cost	**3**	3
Net Amount Recognized	**$ (38)**	$ (35)
Amount Recorded as:		
Accrued Pension Liability	**$ (58)**	$ (51)
Regulated Asset	**13**	—
Accumulated Other Comprehensive Loss	**4**	13
Intangible Asset	**3**	3
	$ (38)	$ (35)

Assumptions used in determining the projected benefit obligation at December 31 are listed below:

	2003	2002	2001
Discount rate	**6.25%**	6.75%	7.25%
Annual increase in future compensation levels	**4.0%**	4.0%	4.0%

Assumptions used in determining net pension costs at December 31 are listed below:

	2003	2002	2001
Discount rate	**6.75%**	7.25%	7.50%
Annual increase in future compensation levels	**4.0%**	4.0%	4.0%

At December 31, 2003, under SFAS No. 87, the minimum pension liability was $20 million, intangible asset was $3 million, regulatory asset was $13 million, other comprehensive loss was $4 million ($3 million after tax) and deferred taxes were $1 million.

Other Postretirement Benefits

We provide certain postretirement health care and life insurance benefits for employees who become eligible for these benefits while working for us.

Net postretirement cost for the years ended December 31 includes the following components:

(in Millions)	2003	2002	2001
Service Cost	**$ 37**	$ 30	$ 27
Interest Cost	**87**	78	67
Expected Return on Plan Assets	**(47)**	(59)	(57)
Amortization of			
Net loss	**31**	3	1
Prior service cost	**(3)**	(1)	—
Net transition obligation	**13**	19	20
Special Termination Benefits (Note 3)	**—**	—	46
Net Postretirement Cost	**$118**	$ 70	$104

The following table reconciles the obligations, assets and funded status of the plans including amounts recorded as accrued postretirement cost in the consolidated statement of financial position at December 31:

(in Millions)	2003	2002
Measurement Date	December 31	December 31
Accumulated Postretirement Benefit Obligation at the Beginning of the Period	**$ 1,494**	$ 1,127
Service Cost	**37**	30
Interest Cost	**87**	78
Actuarial Loss	**162**	326
Plan Amendments	**(126)**	—
Benefits Paid	**(72)**	(67)
Accumulated Postretirement Benefit Obligation at the End of the Period	**$ 1,582**	$ 1,494
Plan Assets at Fair Value at the Beginning of the Period	**$ 537**	$ 624
Actual Return on Plan Assets	**114**	(60)
Company Contributions	**—**	33
Benefits Paid	**(65)**	(60)
Plan Assets at Fair Value at the End of the Period	**$ 586**	$ 537
Funded Status of the Plans	**$ (996)**	$ (957)
Unrecognized		
Net loss	**705**	641
Prior service cost	**(27)**	(7)
Net transition obligation	**74**	191
Accrued Postretirement Liability	**$ (244)**	$ (132)

Assumptions used in determining the projected benefit obligation at December 31 are listed below:

	2003	2002	2001
Discount rate	**6.25%**	6.75%	7.25%

Table of Contents

Assumptions used in determining benefit costs at December 31 are listed below:

	2003	2002	2001
Discount rate	**6.75%**	7.25%	7.50%
Expected long-term rate of return on Plan assets	**9.0%**	9.5%	9.5%

Benefit costs were calculated assuming health care cost trend rates beginning at 9.0% for 2004 and decreasing to 5.0% in 2009 and thereafter for persons under age 65 and decreasing from 8.0% to 5.0% for persons age 65 and over. A one-percentage-point increase in health care cost trend rates would have increased the total service cost and interest cost components of benefit costs by $18 million. The accumulated benefit obligation would have increased by $148 million at December 31, 2003. A one-percentage-point decrease in the health care cost trend rates would have decreased the total service and interest cost components of benefit costs by $16 million and would have decreased the accumulated benefit obligation by $132 million at December 31, 2003.

The Company amended its postretirement health care and life insurance plans to reduce benefits, modify eligibility criteria and increase retiree co-pays. The changes reduced the postretirement benefit obligation by $126 million, the 2003 postretirement costs by $17 million and the expected 2004 postretirement costs by $29 million.

We employ a consistent formal process in determining the long-term rate of return for various asset classes. We evaluate input from our consultants, including their review of historic financial market risks and returns and long-term historic relationships between the asset classes of equities, fixed income and other assets, consistent with the widely accepted capital market principle that asset classes with higher volatility generate a greater return over the long-term. Current market factors such as inflation, interest rates, asset class risks and asset class returns are evaluated and considered before long-term capital market assumptions are determined. The long-term portfolio return is also established employing a consistent formal process, with due consideration of diversification, active investment management and rebalancing. Peer data is reviewed to check for reasonability.

We employ a total return investment approach whereby a mix of equities, fixed income and other investments are used to maximize the long-term return of plan assets consistent with prudent levels of risk. The intent of this strategy is to minimize plan expenses over the long-term. Risk tolerance is established through consideration of future plan cash flows, plan funded status, and corporate financial considerations. The investment portfolio contains a diversified blend of equity, fixed income and other investments. Furthermore, equity investments are diversified across U.S and non-U.S. stocks, growth and value investment styles, and large and small market capitalizations. Other assets such as private equity and absolute return funds are used judiciously to enhance long term returns while improving portfolio diversification. Derivatives may be used to gain market exposure in an efficient and timely manner; however, derivatives may not be used to leverage the portfolio beyond the market value of the underlying investments. Investment risk is measured and monitored on an ongoing basis through annual liability measurements, periodic asset/liability studies, and quarterly investment portfolio reviews.

Our Plans' weighted-average asset allocations by asset category at December 31 are as follows:

	2003	2002
Equity Securities	**66%**	61%
Debt Securities	**30**	35
Other	**4**	4
	100%	100%

Our Plans' weighted-average asset target allocations by asset category at December 31, 2003 are as follows:

Equity Securities	65%
Debt Securities	28
Other	7
	100%

We made a $40 million cash contribution to our postretirement health care and life insurance plans in January 2004.

In December 2003, the Medicare Prescription Drug, Improvement and Modernization Act was signed into law. This Act provides for a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to the benefit established by law. We have elected to defer the provisions of the Act, and our measures of the accumulated postretirement benefit obligation or net periodic postretirement benefit cost do not reflect the effects of the Act, if any. Specific authoritative guidance, when issued by the FASB, could require us to re-determine the impact of the Act and change previously reported information.

Grantor Trust

MichCon maintains a Grantor Trust that invests in life insurance contracts and income securities. Employees and retirees have no right, title or interest in the assets of the Grantor Trust, and MichCon can revoke the trust subject to providing the MPSC with prior notification. We record our investment at market value and account for unrealized gains and losses in the Consolidated Statement of Operations.

NOTE 15 – STOCK-BASED COMPENSATION

The DTE Energy Company 2001 Stock Incentive Plan permits the grant of incentive stock options, non-qualifying stock options, stock awards, performance shares and performance units. A maximum of 18 million shares of common stock may be issued under the plan. Participants in the plan include our employees and Board members. As of December 31, 2003, no performance units have been granted under the plan.

Prior to 2001, stock options, stock awards and performance shares were issued under the Long-Term Incentive Plan adopted in 1995.

Options

Options are exercisable at a rate according to the terms of the individual stock option award agreements. The options will expire 10 years after the date of the grant. The option exercise price equals the fair value of the stock on the date that the option was granted. Stock option activity was as follows:

Table of Contents

	Number of Options	Weighted Average Exercise Price
Outstanding at January 1, 2001 (442,431 exercisable)	2,982,225	$ 33.69
Granted	2,775,341	$ 42.74
Exercised	(402,442)	$ 32.31
Canceled	(73,500)	$ 36.26
Outstanding at December 31, 2001 (1,678,870 exercisable)	5,281,624	$ 38.51
Granted	1,334,370	$ 42.08
Exercised	(678,715)	$ 34.64
Canceled	(456,684)	$ 38.74
Outstanding at December 31, 2002 (2,285,323 exercisable)	**5,480,595**	**$ 39.87**
Granted	**1,654,879**	**$ 40.56**
Exercised	**(329,528)**	**$ 35.88**
Canceled	**(152,824)**	**$ 42.67**
Outstanding at December 31, 2003 (3,506,038 exercisable at a weighted average exercise price of $39.14)	**6,653,122**	**$ 40.18**

The range of exercise prices for options outstanding at December 31, 2003, was $27.62 to $46.74. The number, weighted average exercise price and weighted average remaining contractual life of options outstanding were as follows:

Range of Exercise Prices	Number of Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life
$27.62 - $38.04	1,253,366	$ 31.63	5.88 years
$38.60 - $42.44	3,657,880	$ 41.21	8.01 years
$42.60 - $44.54	810,826	$ 42.69	7.37 years
$45.28 - $46.74	931,050	$ 45.45	7.47 years
	6,653,122	$ 40.18	7.45 years

We apply APB Opinion 25, "*Accounting for Stock Issued to Employees*." Accordingly, no compensation expense has been recorded for options granted. As required by SFAS No. 123, "*Accounting for Stock-Based Compensation* ," we have determined fair value for these options at the date of grant using a Black-Scholes based option pricing model and the following assumptions:

	2003	2002	2001
Risk-free interest rate	**2.93%**	5.33%	5.40%
Dividend yield	**4.97%**	4.90%	4.73%
Expected volatility	**20.89%**	19.79%	19.78%
Expected life	**6 years**	6 years	10 years
Fair value per option	**$ 4.78**	$ 6.25	$ 8.81

Stock Awards

Under the plan, stock awards are granted and restricted for varying periods, which currently do not exceed four years. Participants have all rights of a shareholder with respect to a stock award, including the right to receive dividends and vote the shares; provided, that during such period (i) a participant may not sell, transfer, pledge, exchange or otherwise dispose of shares granted pursuant to a stock award; (ii) we shall retain custody of the certificates evidencing shares granted pursuant to a stock award; and (iii) the participant will deliver to us a stock power with respect to each stock award.

The stock awards are recorded at cost that approximates the market value on the date of grant. We account for stock awards as unearned compensation, which is recorded as a reduction to common stock. The cost is amortized to compensation expense over the vesting period. Stock award activity for the years ended December 31 was:

	2003	2002	2001
Restricted common shares awarded	**102,060**	113,410	247,640
Weighted average market price of shares awarded	**$ 41.39**	$ 42.92	$ 44.35
Compensation cost charged against income (in thousands)	**$ 6,366**	$ 4,101	$ 2,484

Performance Share Awards

Under the plan, performance shares are awards stated with reference to a specified number of shares of common stock that entitles the holder to receive a cash payment or shares of common stock or a combination thereof. The final value of the award is determined by the achievement of certain performance objectives, as defined in the plan. The awards vest as of the end of a specified period. Beginning with the grant date, we account for performance share awards by accruing an amount based on the following: (i) the number of shares expected to be awarded based on the probable achievement of certain performance objectives, (ii) the market value of the shares, and (iii) the vesting period. For 2003, 2002 and 2001, we accrued compensation expense related to performance share awards totaling $5.5 million, $3.6 million and $1.2 million, respectively.

During the applicable restriction period, the recipient of a performance share award has no shareholder rights. However, recipients will be paid an amount equal to the dividend equivalent on such shares. Performance share awards are nontransferable and are subject to risk of forfeiture. As of December 31, 2003, there were 617,404 performance share awards outstanding.

NOTE 16 - SEGMENT AND RELATED INFORMATION

Beginning in 2002, we realigned our internal and external financial reporting structure into three strategic business units (Energy Resources, Energy Distribution and Energy Gas) that have both regulated and non-regulated operations. The balance of our business consists of Corporate & Other. Based on this structure we set strategic goals, allocate resources and evaluate performance. This results in the following nine reportable segments:

Energy Resources

- *Regulated – Power Generation* operations include the power generation services of Detroit Edison, the company's electric utility. Electricity is generated from Detroit Edison's numerous fossil plants or its nuclear plant and sold throughout Southeastern Michigan to residential, commercial, industrial and wholesale customers.

- *Non-regulated*

  - *Energy Services* is comprised of various businesses that develop, acquire and manage energy-related assets and services. Such projects include coke production, synfuels production, on-site energy projects and merchant generation facilities.

  - *Energy Marketing & Trading* consists of the electric and gas marketing and trading operations of DTE Energy Trading Company and the natural gas marketing and trading operations of DTE Enterprises, which was acquired as part of the MCN Energy acquisition. Energy Marketing & Trading enters into forwards, futures, swaps and option contracts as part of its trading strategy.

  - *Other non-regulated* operations consist of businesses involved in coal services and landfill gas recovery.

Energy Distribution

- *Regulated — Power Distribution* operations include the electric distribution services of Detroit Edison. Energy Distribution distributes electricity generated by Energy Resources to Detroit Edison's 2.1 million residential, commercial and industrial customers.

- *Non-regulated* operations include businesses that market and distribute a broad portfolio of distributed generation products, provide application engineering, and monitor and manage system operations.

Energy Gas

- *Regulated* operations include gas distribution services provided by MichCon, the company's gas utility that purchases, stores and distributes natural gas throughout Michigan to 1.2 million residential, commercial and industrial customers.

- *Non-regulated* operations include the production of gas and the gathering, processing and storing of gas. Certain pipeline and storage assets are primarily supported by the Energy Marketing & Trading segment.

Corporate & Other includes administrative and general expenses, and interest costs of DTE Energy corporate that have not been allocated to the regulated and non-regulated businesses. Corporate & Other also includes various other non-regulated operations, including investments in new emerging energy technologies.

The income tax provisions or benefits of DTE Energy's subsidiaries are determined on an individual company basis and recognize the tax benefit of Section 29 tax credits and net operating losses. The subsidiaries record income tax payable to or receivable from DTE Energy resulting from the inclusion of its taxable income or loss in DTE Energy's consolidated tax return. Inter-segment revenues are not material. Financial data of the business segments follows:

Table of Contents

(in Millions)

2003	Operating Revenue	Depreciation, Depletion & Amortization	Interest Expense	Income Taxes	Net Income	Total Assets	Goodwill	Capital Expenditures
Energy Resources								
Regulated – Power Generation	$2,448	$ 224	$ 157	$ 135	$235	$ 7,216	$ 406	$ 340
Non-Regulated								
Energy Services	929	84	20	(249)	199	1,644	41	22
Energy Marketing & Trading	764	2	2	20	45	1,067	17	6
Other	297	7	2	(17)	(2)	128	4	11
Total Non-Regulated	1,990	93	24	(246)	242	2,839	62	39
Total Energy Resources	4,438	317	181	(111)	477	10,055	468	379
Energy Distribution								
Regulated – Power Distribution	1,247	249	127	10	17	5,333	796	240
Non-Regulated	39	2	—	(8)	(15)	65	12	1
	1,286	251	127	2	2	5,398	808	241
Energy Gas								
Regulated – Gas Distribution	1,498	101	58	—	29	3,035	776	99
Non-Regulated	90	18	8	14	29	518	15	28
	1,588	119	66	14	58	3,553	791	127
Corporate & Other	12	—	219	(28)	(57)	2,383	—	4
Reconciliation & Eliminations	(283)	—	(47)	—	—	(636)	—	—
Total from Continuing Operations	$ 7,041	$ 687	$ 546	$ (123)	480	20,753	2,067	751
Discontinued Operations (Note 3)					68	—	—	—
Cumulative Effect of Accounting Changes					(27)	—	—	—
Total					$ 521	$20,753	$2,067	$ 751

(in Millions)

2002	Operating Revenue	Depreciation, Depletion & Amortization	Interest Expense	Income Taxes	Net Income	Total Assets	Goodwill	Capital Expenditures
Energy Resources								
Regulated – Power Generation	$ 2,711	$ 331	$ 184	$ 120	$ 241	$ 7,334	$ 406	$ 395
Non-Regulated								
Energy Services	645	81	19	(268)	182	1,536	41	130
Energy Marketing & Trading	681	3	15	13	25	822	17	—
Other	102	9	4	(19)	7	256	4	8
Total Non-Regulated	1,428	93	38	(274)	214	2,614	62	138
Total Energy Resources	4,139	424	222	(154)	455	9,948	468	533
Energy Distribution								
Regulated – Power Distribution	1,343	246	127	58	111	4,154	796	290
Non-Regulated	39	2	1	(9)	(16)	60	12	2
	1,382	248	128	49	95	4,214	808	292
Energy Gas								
Regulated – Gas Distribution	1,369	104	57	36	66	2,871	776	93
Non-Regulated	87	19	6	14	26	504	16	32
	1,456	123	63	50	92	3,375	792	125
Corporate & Other	16	—	232	(32)	(56)	2,378	—	24
Reconciliation & Eliminations	(264)	(58)	(76)	3	—	(548)	—	—
Total from Continuing Operations	$6,729	$ 737	$ 569	$ (84)	586	19,367	2,068	974
Discontinued Operations (Note 3)					46	618	44	10
Total					$632	$ 19,985	$ 2,112	$ 984

Table of Contents

(in Millions)

2001	Operating Revenue	Depreciation, Depletion & Amortization	Interest Expense	Income Taxes	Net Income	Total Assets	Capital Expenditures
Energy Resources							
Regulated – Power Generation	$2,788	$ 385	$ 181	$ 58	$ 139	$ 7,400	$ 348
Non-Regulated							
Energy Services	447	85	25	(173)	115	1,185	257
Energy Marketing & Trading	554	2	13	24	44	835	—
Other	143	10	5	(15)	6	206	—
Total Non-Regulated	1,144	97	43	(164)	165	2,226	257
Total Energy Resources	3,932	482	224	(106)	304	9,626	605
Energy Distribution							
Regulated – Power Distribution	1,256	246	125	26	97	4,073	325
Non-Regulated	21	1	1	(6)	(10)	66	5
	1,277	247	126	20	87	4,139	330
Energy Gas							
Regulated – Gas Distribution	615	61	34	(49)	(38)	2,886	66
Non-Regulated	51	12	7	5	11	486	23
	666	73	41	(44)	(27)	3,372	89
Corporate & Other	11	29	127	(28)	(55)	2,324	50
Reconciliation & Eliminations	(99)	(49)	(36)	39	—	(449)	—
Total from Continuing Operations	$5,787	$ 782	$482	$ (119)	309	19,012	1,074
Discontinued Operations (Note 3)					20	575	22
Cumulative Effect of Accounting Changes					3	—	—
Total					$332	$19,587	$ 1,096

Table of Contents

NOTE 17 SUPPLEMENTARY QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Quarterly earnings per share may not total for the years, since quarterly computations are based on weighted average common shares outstanding during each quarter. In February 2003, we sold ITC which has been accounted for as a discontinued operation (Note 3).

(in Millions, except per share amounts)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
2003					
Operating Revenues	**$2,095**	**$1,600**	**$1,654**	**$1,692**	**$7,041**
Operating Income	**$ 217**	**$ 71**	**$ 232**	**$ 227**	**$ 747**
Net Income (Loss)					
From continuing operations	**$ 108**	**$ (37)**	**$ 180**	**$ 229**	**$ 480**
Discontinued operations	**74**	**(2)**	**(4)**	**—**	**68**
Cumulative effect of accounting changes	**(27)**	**—**	**—**	**—**	**(27)**
Total	**$ 155**	**$ (39)**	**$ 176**	**$ 229**	**$ 521**
Basic Earnings (Loss) per Share					
From continuing operations	**$ .65**	**$ (.22)**	**$ 1.07**	**$ 1.36**	**$ 2.87**
Discontinued operations	**.44**	**(.01)**	**(.02)**	**—**	**.41**
Cumulative effect of accounting changes	**(.17)**	**—**	**—**	**—**	**(.17)**
Total	**$ .92**	**$ (.23)**	**$ 1.05**	**$ 1.36**	**$ 3.11**
Diluted Earnings (Loss) per Share					
From continuing operations	**$ .64**	**$ (.22)**	**$ 1.06**	**$ 1.36**	**$ 2.85**
Discontinued operations	**.44**	**(.01)**	**(.02)**	**—**	**.40**
Cumulative effect of accounting changes	**(.16)**	**—**	**—**	**—**	**(.16)**
Total	**$ .92**	**$ (.23)**	**$ 1.04**	**$ 1.36**	**$ 3.09**
2002					
Operating Revenues	$1,894	$1,474	$1,615	$1,746	$6,729
Operating Income	$ 333	$ 180	$ 235	$ 246	$ 994
Net Income					
From continuing operations	$ 192	$ 61	$ 139	$ 194	$ 586
Discontinued operations	8	7	22	9	46
Total	$ 200	$ 68	$ 161	$ 203	$ 632
Basic Earnings per Share					
From continuing operations	$ 1.20	$ .38	$ .83	$ 1.17	$ 3.57
Discontinued operations	.05	.04	.13	.05	.28
Total	$ 1.25	$ .42	$ .96	$ 1.22	$ 3.85
Diluted Earnings per Share					
From continuing operations	$ 1.19	$ .38	$ .83	$ 1.16	$ 3.55
Discontinued operations	.05	.04	.13	.05	.28
Total	$ 1.24	$ .42	$ .96	$ 1.21	$ 3.83

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

(a) Evaluation of disclosure controls and procedures

The Company's Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of the Company's disclosure controls and procedures (as defined in Exchange Act Rules 13a – 15(e) and 15d – 15(e)) as of December 31, 2003, which is the end of the period covered by this report, and have concluded that such controls and procedures are effectively designed to ensure that required information disclosed by the Company in reports that it files or submits under the Act is recorded, processed, summarized and reported within the time periods specified in the Commission's rules and forms.

Part III

Item 10. Directors and Executive Officers of the Registrant

Item 11. Executive Compensation

Item 12. Security Ownership of Certain Beneficial Owners and Management

Item 13. Certain Relationships and Related Transactions

Item 14. Principal Accountant Fees and Services

Information required by Part III (Items 10, 11, 12, 13 and 14) of this Form 10-K is incorporated by reference from the company's definitive Proxy Statement for its 2004 Annual Meeting of Common Shareholders. The annual meeting will be held April 29, 2004. The Proxy Statement will be filed with the Securities and Exchange Commission, pursuant to Regulation 14A, not later than 120 days after the end of our fiscal year covered by this report on Form 10-K, all of which information is hereby incorporated by reference in, and made part of, this Form 10-K, except that the information required by Item 10 with respect to executive officers of the Registrant is included in Part I of this report.

Part IV

Item 15. Exhibits, Financial Statement Schedule and Reports on Form 8-K

(a) The following documents are filed as part of this Annual Report on Form 10-K.

(1) Consolidated financial statements. See "Item 8 – Financial Statements and Supplementary Data."

(2) Financial statement schedule. See "Item 8 – Financial Statements and Supplementary Data."

(3) Exhibits.

Exhibit Number	Description
(i)	Exhibits filed herewith.
12-33	Computation of Ratio of Earnings to Fixed Charges.
23-16	Consent of Deloitte & Touche LLP.
31-5	Chief Executive Officer Section 302 Form 10-K Certification of Periodic Report.
31-6	Chief Financial Officer Section 302 Form 10-K Certification of Periodic Report.
(ii)	Exhibits incorporated herein by reference.
2-1	Agreement and Plan of Merger, among DTE Energy Company, MCN Energy Group Inc. and DTE Enterprises, Inc., dated as of October 4, 1999, as amended as of November 12, 1999, as further amended as of February 28, 2001. (Exhibit 2-2 to Form 10-K for year ended December 31, 2000).
3(a)	Amended and Restated Articles of Incorporation of DTE Energy Company, dated December 13, 1995 (Exhibit 3-5 to Form 10-Q for quarter ended September 30, 1997).
3(b)	Certificate of Designation of Series A Junior Participating Preferred Stock of DTE Energy Company (Exhibit 3-6 to Form 10-Q for quarter ended September 30, 1997).
3(c)	Restated Articles of Incorporation of Detroit Edison, as filed December 10,1991 with the State of Michigan, Department of Commerce – Corporation and Securities Bureau (Exhibit 3-13 to Form 10-Q for quarter ended June 30, 1999).
3(d)	Rights Agreement, dated as of September 23, 1997, by and between DTE Energy Company and The Detroit Edison Company, as Rights Agent (Exhibit 4-1 to DTE Energy Company Current Report on Form 8-K, dated September 23, 1997).
3(e)	Bylaws of DTE Energy Company, as amended through September 22, 1999 (Exhibit 3-3 to Registration No. 333-89175).
4(a)	Amended and Restated Indenture, dated as of April 9, 2002, between DTE Energy Corporation and The Bank of New York, as Trustee (Exhibit 4-1 to Registration No. 333-588834).
4(b)	First Supplemental Indenture, dated as of April 9, 2001, between DTE Energy and The Bank of New York (Exhibit 4-223 to Form 10-Q for quarter ended March 31, 2001).
4(c)	Second Supplemental Indenture, dated as of April 9, 2001, between DTE Energy and The Bank of New York, as trustee (Exhibit 4-224 to Form 10-Q for quarter ended March 31, 2001).
4(d)	Third Supplemental Indenture, dated as of April 9, 2001, among DTE Capital Corporation, DTE Energy and The Bank of New York, as trustee (Exhibit 4-225 to Form 10-Q for quarter ended March 31, 2001).
4(e)	Guaranty of Enterprises securities (Exhibit 4-227 to Form 10-K for year ended December 31, 2001).
4(f)	Fourth Supplemental Indenture creating 7.8% Subordinated Debentures (Exhibit 4-228 to Form 10-K for year ended December 31, 2001).

Exhibit Number	Description
4(g)	Amended and Restated Trust Agreement of DTE Energy Trust 1 (Exhibit 4-228 to Form 10-K for year ended December 31, 2001).
4(h)	Supplemental Indenture dated as of May 30, 2001 to Indenture dated as of April 2001 (Exhibit 4-226 to Form 10-Q for quarter ended March 31, 2001).
4(i)	Supplemental Indenture dated as of April 5, 2002, creating the 2002 Series A 6.65% Senior Notes due 2009 (Exhibit 4-230 to Form 10-Q for quarter ended March 31, 2002).
4(j)	Pledge Agreement dated as of June 25, 2002, between DTE and the Bank of New York (Exhibit 4-231 to Form 10-Q for quarter ended June 30, 2002).
4(k)	Purchase Contract Agreement dated as of June 25, 2002, between DTE and the Bank of New York (Exhibit 4-232 to Form 10-Q for quarter ended June 30, 2002).
4(l)	Supplemental Indenture dated as of June 25, 2002, between DTE and the Bank of New York (Exhibit 4-233 to Form 10-Q for quarter ended June 30, 2002).
4(m)	Trust Agreement of DTE Energy Trust II (Exhibit 4-12 to DTE Energy Trust II's registration statement on Form S-3 (File No. 333-74338-01)).
4(n)	Trust Agreement of DTE Energy Trust III (Exhibit 4-21 to DTE Energy Trust II's registration statement on Form S-3 (File No. 333-99955)).
4(o)	Supplemental Indenture dated as of April 1, 2003, Supplementing the Amended and Restated Indenture dated as of April 9, 2001 providing for 2003 Series A 6 3/8% Senior Notes Due 2033 (Exhibit 4-(o) to Form 10-Q for quarter ended March 31, 2003).
10(a)	DTE Energy Annual Incentive Plan (Exhibit 10-44 to Form 10-Q for quarter ended March 31, 2001).
10(b)	Form of Change-in-Control Severance Agreement, dated as of October 1, 1997, between DTE Energy Company and its officers (Exhibit 10-9 to Form 10-Q for quarter ended September 30, 1997).
10(c)	Form of 1995 Indemnification Agreement between the Company and its directors and officers (Exhibit 3L (10-1) to DTE Energy Company Form 8- B dated January 2, 1996).
10(d)	Certain arrangements pertaining to the employment of S. Martin Taylor (Exhibit 10-38 to Detroit Edison's Form 10-Q for quarter ended March 31, 1998).
10(e)	Amended and Restated Post-Employment Income Agreement dated March 23, 1998, between Detroit Edison and Anthony F. Earley, Jr. (Exhibit 10-20 to Form 10-Q for quarter ended March 31, 1998).
10(f)	Restricted Stock Agreement, dated March 23, 1998, between Detroit Edison and Anthony F. Earley, Jr. (Exhibit 10-20 to Form 10-Q for quarter ended March 31, 1998).
10(g)	Amended and Restated Detroit Edison Savings Reparation Plan (February 23, 1998) (Exhibit 10-19 for quarter ended March 31, 1998).
10(h)	Fourth Restatement of The Benefit Equalization Plan for Certain Employees of The Detroit Edison Company (October 1997) (Exhibit 10-11 to Form 10-K for year ended December 31, 1997).
10(i)	Amended and Restated Executive Incentive Plan (Exhibit 10-35 to Form 10-Q for the quarter ended March 31, 2000).
10(j)	Trust Agreement for DTE Energy Company Change-In-Control Severance Agreements between DTE Energy Company and Wachovia Bank, N.A. (Exhibit 10-16 to Form 10-K for year ended December 31, 1997).
10(k)	Certain arrangements pertaining to the employment of David E. Meador (Exhibit 10-5 to Form 10-K for year ended December 31, 1997).
10(l)	Amended and Restated Supplemental Long-Term Disability Plan, dated January 27, 1997 (Exhibit 10-4 to Form 10-K for year ended December 31, 1996).

10(m) Fourth Restatement of the Retired Reparation Plan for Certain Employees of The Detroit Edison Company (October 1997) (Exhibit 10-10 to 10-K for year ended December 31, 1997).

10(n) Sixth Restatement of The Detroit Edison Company Management Supplemental Benefit Plan (1998) (Exhibit 10-27 to Form 10-K for year ended December 31, 1998).

10(o) DTE Energy Company Plan for Deferring the Payment of Directors' Fees (As Amended and Restated Effective As of January 1, 1999) (Exhibit 10-29 to Form 10-K for year ended December 31, 1998).

10(p) DTE Energy Company Deferred Stock Compensation Plan for Non-Employee Directors,

Table of Contents

Exhibit Number	Description
	effective as of January 1, 1999 (Exhibit 10-30 to Form 10-K for year ended December 31, 1998).
10(q)	DTE Energy Company Retirement Plan for Non-Employee Directors (As Amended and Restated Effective As Of December 31, 1998) (Exhibit 10-31 to Form 10-K for year ended December 31, 1998).
10(r)	Executive Vehicle Plan (Exhibit 10-41 to Form 10-Q for quarter ended March 31, 2001).
10(s)	DTE Energy 2001 Stock Incentive Plan (Exhibit 10-43 to Form 10-Q for quarter ended March 31, 2001).
10(t)	Consulting Agreement with A.R. Glancy, III (Exhibit 10-41 to Form 10-K for year ended December 31, 2001).
10(u)	2002 Measures and Targets for Stock Incentive Plan (Exhibit 10-42 to Form 10-K for year ended December 31, 2001).
10(v)	2002 Measures and Target for Annual Incentive Plan (Exhibit 10-43 to Form 10-K for year ended December 31, 2001).
10(w)	Supplemental Savings Plan (Exhibit 10-44 to Form 10-Q for quarter ended June 30, 2002).
10(x)	Executive Deferred Compensation Plan (Exhibit 10-45 to Form 10-Q for quarter ended June 30, 2002).
10(y)	Supplemental Retirement Plan (Exhibit 10-46 to Form 10-Q for quarter ended June 30, 2002).
10(z)	Executive Life Insurance Plan (Exhibit 10-47 to Form 10-Q for quarter ended June 30, 2002).
10(aa)	Employment Contract of Bruce D. Peterson (Exhibit 10-48 to Form 10-Q for quarter ended June 30, 2002).
10(bb)	DTE Energy Affiliates Nonqualified Plans Master Trust effective May 1, 2003 (Exhibit 10- 49) to Form 10-Q for quarter ended March 31, 2003).
10(cc)	DTE Energy Annual & Long Term Incentive Programs (Exhibit 10- 50) to Form 10-Q for quarter ended June 30, 2003).
21(a)	Subsidiaries of the Company (Form U-3A-2 filed March 1, 2004 (File No. 069-00395)).
99(a)	Master Trust Agreement (“Master Trust”), dated as of June 30, 1994, between Detroit Edison and Fidelity Management Trust Company relating to the Savings and Investment Plans (Exhibit 4-167 to Form 10-Q for quarter ended June 30, 1994).
99(b)	First Amendment, effective as of February 1, 1995, to Master Trust (Exhibit 4-10 to Registration No. 333-00023).
99(c)	Second Amendment, effective as of February 1, 1995 to Master Trust (Exhibit 4-11 to Registration No. 333-00023).
99(d)	Third Amendment, effective January 1, 1996, to Master Trust (Exhibit 4-12 to Registration No. 333-00023).
99(e)	Fourth Amendment to Trust Agreement between Fidelity Management Trust Company and The Detroit Edison Company (July 1996) (Exhibit 4-185 to Form 10-K for the year ended December 31, 1997).
99(f)	Fifth Amended to Trust Agreement Between Fidelity Management Trust Company and The Detroit Edison Company (December 1997) (Exhibit 4-186 to Form 10-K for the year ended December 31, 1997).
99(g)	The Detroit Edison Company Irrevocable Grantor Trust for The Detroit Edison Company Savings Reparation Plan (Exhibit 99-1 to Form 10-K for year ended December 31, 1996).
99(h)	The Detroit Edison Company Irrevocable Grantor Trust for The Detroit Edison Company Retirement Reparation Plan (Exhibit 99-2 to Form 10-K for year ended December 31, 1996).
99(i)	The Detroit Edison Company Irrevocable Grantor Trust for The Detroit Edison Company Management Supplemental Benefit Plan (Exhibit 99-3 to Form 10-K for year ended December 31, 1996).

99(j)	The Detroit Edison Company Irrevocable Grantor Trust for The Detroit Edison Company Benefit Equalization Plan (Exhibit 99-4 to Form 10-K for year ended December 31, 1996).
99(k)	The Detroit Edison Company Irrevocable Grantor Trust for The Detroit Edison Company Plan for Deferring the Payment of Directors' Fees (Exhibit 99-5 to Form 10-K for year ended December 31, 1996).

Exhibit Number	Description
99(l)	The Detroit Edison Company Irrevocable Grantor Trust for The DTE Energy Company Retirement Plan for Non-Employee Directors (Exhibit 99-6 to Form 10-K for year ended December 31, 1996).
99(m)	DTE Energy Company Irrevocable Grantor Trust for the DTE Energy Company Plan for Deferring the Payment of Directors' Fees (Exhibit 99-7 to Form 10-K for year ended December 31, 1996).
99(n)	364-Day Credit Agreement dated as of October 24, 2003 ($350 million) (Exhibit 99-13 to Form 10-Q for the quarter ended September 30, 2003).
99(o)	Three Year Credit Agreement dated as of October 24, 2003($350 million) (Exhibit 99-14 to Form 10-Q for the quarter ended September 30, 2003).
(iii)	Exhibits furnished herewith.
32-5	Chief Executive Officer Section 906 Form 10-K Certification of Periodic Report.
32-6	Chief Financial Officer Section 906 Form 10-K Certification of Periodic Report.

(b) Reports on Form 8-K.

During the quarterly period ended December 31, 2003, we filed Current Reports on Form 8-K covering matters, as follows:

Item 5. Other Events and Item 7. Financial Statements and Exhibits filed and dated October 30, 2003.

Item 7. Exhibits and Item 12. Results of Operations and Financial Conditions filed and dated November 7, 2003;

Item 5. Other Events and Item 7. Financial Statements and Exhibits filed and dated November 14, 2003.

DTE Energy Company
Schedule II – Valuation and Qualifying Accounts

(in Millions)	2003	2002	2001
	Year Ending December 31,		
Allowance for Doubtful Accounts (shown as Deduction from accounts receivable in the consolidated statement of financial position)			
Balance at Beginning of Period	**$ 82**	$ 57	$ 21
Additions:			
Charged to costs and expenses	**80**	45	36
Balance acquired with MCN Energy acquisition	**—**	—	30
Charged to other accounts (1)	**4**	15	11
Deductions (2)	**(67)**	(35)	(41)
Balance At End of Period	**$ 99**	$ 82	$ 57
Fermi 2 Refueling Outage Accrual (included in other Current liabilities in the consolidated statement of financial position)			
Balance at Beginning of Period	**$ 25**	$ 1	$ 10
Charged to costs and expenses	**23**	25	13
Deductions (3)	**(32)**	(1)	(22)
Balance At End of Period	**$ 16**	$ 25	$ 1

(1) Collection of accounts previously written off.

(2) Non-collectible accounts written off.

(3) Actual amounts paid during the refueling outage.

Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

DTE ENERGY COMPANY

(Registrant)

Date: March 1, 2004

By /s/ ANTHONY F. EARLEY, JR.

Anthony F. Earley, Jr.
Chairman of the Board,
Chief Executive Officer, President
and Chief Operating Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated.

By	/s/ ANTHONY F. EARLEY, JR. Anthony F. Earley, Jr. Chairman of the Board, Chief Executive Officer, President and Chief Operating Officer	By	/s/ DAVID E. MEADOR David E. Meador Senior Vice President and Chief Financial Officer
By	/s/ DANIEL G. BRUDZYNSKI Daniel G. Brudzynski Vice President and Controller	By	/s/ THEODORE S. LEIPPRANDT Theodore S. Leipprandt, Director
By	/s/ TERENCE E. ADDERLEY Terence E. Adderley, Director	By	/s/JOHN E. LOBBIA John E. Lobbia, Director
By	/s/ LILLIAN BAUDER Lillian Bauder, Director	By	/s/ GAIL J. MCGOVERN Gail J. McGovern, Director
By	/s/ DAVE BING David Bing, Director	By	/s/ EUGENE A. MILLER Eugene A. Miller, Director
By	/s/ ALLAN D. GILMOUR Allan D. Gilmour, Director	By	/s/ CHARLES W. PRYOR, JR. Charles W. Pryor, Jr., Director
By	/s/ ALFRED R. GLANCY III Alfred R. Glancy III, Director	By	/s/ JOSUE ROBLES, JR. Josue Robles, Jr., Director
By	/s/ FRANK M. HENNESSEY Frank M. Hennessey, Director	By	/s/ HOWARD F. SIMS Howard F. Sims, Director

Date: March 1, 2004

Table of Contents

Exhibit Index

EXHIBIT NO.	DESCRIPTION
(i)	Exhibits filed herewith.
12-33	Computation of Ratio of Earnings to Fixed Charges.
23-16	Consent of Deloitte & Touche LLP.
31.5	Certification of Chief Executive Officer pursuant to Section 302
31.6	Certification of Chief Financial Officer pursuant to Section 302
32.5	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.6	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

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EXHIBIT 12-33

DTE ENERGY COMPANY
COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES

	(Millions, except for ratio)				
	2003	2002	2001	2000	1999
EARNINGS:					
Pretax earnings	$ 266	$ 465	$ 190	$ 480	$ 546
Add:					
Loss from equity investee	15	14	22	26	15
Fixed charges	570	558	477	370	378
Distributed income from equity investees	11	10	9	-	-
NET EARNINGS	862	1,047	698	876	939
FIXED CHARGES:					
Interest expense	546	554	469	336	344
Interest factor of rents	24	4	8	34	34
Total fixed charges	$ 570	$ 558	$ 477	$ 370	$ 378
Ratio of earnings to fixed charges	1.51	1.88	1.46	2.37	2.48

EXHIBIT 23-16

INDEPENDENT AUDITORS' CONSENT

We consent to the incorporation by reference of our report dated March 1, 2004 (which report expresses an unqualified opinion and includes an explanatory paragraph relating to the change in the methods of accounting for asset retirement obligations, energy trading contracts and gas inventories in 2003, goodwill and energy trading contracts in 2002 and derivative instruments and hedging activities in 2001), appearing in the Annual Report on Form 10-K of DTE Energy Company for the year ended December 31, 2003 in the following registration statements:

FORM	REGISTRATION NUMBER
Form S-3	333-74338
Form S-3	333-99955
Form S-3	333-109591
Form S-4	383-89175
Form S-8	333-61992
Form S-8	333-62192
Form S-8	333-00023
Form S-8	333-47247
Form S-8	333-109623

Detroit, Michigan
March 1, 2004

Exhibit 31-5

FORM 10-K CERTIFICATION

I, Anthony F. Earley, Jr., Chairman, President, Chief Executive and Chief Operating Officer of DTE Energy Company, certify that:

1. I have reviewed this annual report on Form 10-K of DTE Energy Company;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. (Intentionally omitted)

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ ANTHONY F. EARLEY, JR.

Date: March 1, 2004

Anthony F. Earley, Jr.
Chairman, President, Chief Executive and
Chief Operating Officer of DTE Energy Company

Exhibit 31-6

FORM 10-K CERTIFICATION

I, David E. Meador, Senior Vice President and Chief Financial Officer of DTE Energy Company, certify that:

1. I have reviewed this annual report on Form 10-K of DTE Energy Company;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. (Intentionally omitted)

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ DAVID E. MEADOR

Date: March 1, 2004

David E. Meador
Senior Vice President and
Chief Financial Officer of DTE Energy Company

Exhibit 32-5

CERTIFICATION OF PERIODIC REPORT

I, Anthony F. Earley, Jr., Chairman, President, Chief Executive and Chief Operating Officer of DTE Energy Company (the "Company"), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge and belief:

(1) the Annual Report on Form 10-K of the Company for the annual period ended December 31, 2003 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: March 1, 2004

/s/ ANTHONY F. EARLEY, JR.

Anthony F. Earley, Jr.
Chairman, President, Chief Executive and
Chief Operating Officer of DTE Energy Company

Exhibit 32-6

CERTIFICATION OF PERIODIC REPORT

I, David E. Meador, Senior Vice President and Chief Financial Officer of DTE Energy Company (the “Company”), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge and belief:

(1) the Annual Report on Form 10-K of the Company for the annual period ended December 31, 2003 (the “Report”) fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: March 1, 2004

/s/ DAVID E. MEADOR

David E. Meador
Senior Vice President and Chief Financial
Officer of DTE Energy Company